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

FORM 10-K

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

For the fiscal year ended October 31, 2010

or

☐ **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	56-0556998
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

4720 Piedmont Row Drive, Charlotte, North Carolina	28210
(Address of principal executive offices)	(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 ☒ No ☐

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data file required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

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. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒ Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

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

State the aggregate market value of the voting common equity held by non-affiliates of the registrant as of April 30, 2010.

Common Stock, no par value - $1,952,780,258

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 17, 2010
Common Stock, no par value	72,310,563

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the Annual Meeting of Shareholders on March 4, 2011, are incorporated by reference into Part III.

Piedmont Natural Gas Company, Inc.

2010 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 whose principal business is the distribution of natural gas to over one million residential, commercial, industrial and power generation customers in portions of North Carolina, South Carolina and Tennessee, including 51,600 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 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 the cities of Greenville, Rocky Mount and Wilson. In Tennessee, our service area is the metropolitan area of Nashville, including wholesale natural gas service to the cities of Gallatin and Smyrna.

We have two reportable business segments, regulated utility and non-utility activities. The regulated utility segment is the largest segment of our business with approximately 97% of our consolidated assets. Factors critical to the success of the regulated segment include operating a safe, reliable natural gas distribution system and the ability to recover the costs and expenses of the business in the rates charged to customers. For 2010, our earnings before taxes, including the gain from the sale of half of our ownership interest in SouthStar Energy Services LLC (SouthStar) of \$49.7 million, were \$205.6 million, 67% of which 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 and regulated interstate natural gas storage and intrastate natural gas transportation. For 2010, the earnings before taxes from our non-utility activities segment, including the gain from the sale of half of our ownership interest in SouthStar, was 33%, with 4% from regulated non-utility activities and 29% from unregulated non-utility activities.

The generally accepted accounting principles presentation does not adequately reflect our segments because of the inclusion of the gain from the sale of half of our ownership interest in SouthStar, which is in our non-utility activities segment. Excluding this gain for the year ended October 31, 2010, 85% of our earnings before taxes came from our regulated utility segment, and earnings before taxes from our non-utility activities segment was 15%, with 5% from regulated non-utility activities and 10% from unregulated non-utility activities. 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 prudently incurred 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, 2010, 48% of our operating revenues were from residential customers, 28% from commercial customers, 10% from large volume customers, including industrial, power generation and resale customers, and 14% from secondary market activities. Secondary market transactions consist of off-system sales and capacity release arrangements and are part of our utility gas supply management program with regulator-approved sharing mechanisms between our utility customers and our shareholders. Operations of the non-utility activities segment are included in the consolidated statements of income in "Income from equity method investments" and "Non-operating income."

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 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 Federal Energy Regulatory Commission (FERC) that affect the purchase and sale and the prices paid for the interstate transportation and storage of natural gas, regulations of the Department of Transportation that affect the design, construction, operation, maintenance, integrity, safety and security of natural gas distribution and transmission systems, and regulations of the Environmental Protection Agency relating to the environment. 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 many of the communities we serve, with expiration dates from 2011 to 2058. The franchises are adequate for the operation of our gas distribution business and do not contain materially burdensome restrictions or conditions. Nineteen franchise agreements have expired as of October 31, 2010. We continue to operate in those areas pursuant to the provisions of the expired franchises with no significant impact on our business. Four franchise agreements will expire during the 2011 fiscal year. The likelihood of cessation of service under an expired franchise is remote. We believe that these franchises will be renewed or that service will be continued in the ordinary course of business under our state-granted franchise rights without specific franchise agreements with each city or municipality, with no material adverse impact on us.

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 heating season (principally November through March) when customer demand is higher. During the year ended October 31, 2010, the amount of natural gas in storage varied from

13.3 million dekatherms (one dekatherm equals 1,000,000 BTUs) to 26.9 million dekatherms, and the aggregate commodity cost of this gas in storage varied from $77.5 million to $145.9 million.

During the year ended October 31, 2010, 154.3 million dekatherms of gas were sold to or transported for large volume customers compared with 123.1 million dekatherms in 2009. Of these volumes sold to or transported for large volume customers, we transported 63 million dekatherms this year to power generation facilities as compared with 39.6 million dekatherms in the prior year. The margin earned from power generation customers does not vary significantly with volumes. Deliveries to temperature-sensitive residential and commercial customers, whose consumption varies with the weather, totaled 98.3 million dekatherms in 2010, compared with 93.8 million dekatherms in 2009. Weather, as measured by degree days, was 6% colder than normal in 2010 and 3% colder than normal in 2009.

The following is a five-year comparison of operating statistics for the years ended October 31, 2006 through 2010.

	2010	2009	2008	2007	2006
Operating Revenues (in thousands):					
Sales and Transportation:					
Residential	$ 743,346	$ 787,994	$ 813,032	$ 743,637	$ 841,051
Commercial	428,085	462,160	503,317	418,426	498,956
Industrial	116,122	126,855	209,341	190,204	205,384
For Power Generation	21,708	19,609	25,266	29,135	22,963
For Resale	11,061	11,746	12,326	13,907	11,342
Total	1,320,322	1,408,364	1,563,282	1,395,309	1,579,696
Secondary Market Sales	224,973	221,300	515,968	308,904	337,278
Miscellaneous	7,000	8,452	9,858	7,079	7,654
Total	$ 1,552,295	$ 1,638,116	$ 2,089,108	$ 1,711,292	$ 1,924,628
Gas Volumes - Dekatherms (in thousands):					
System Throughput:					
Residential	58,327	55,298	51,909	50,072	49,119
Commercial	39,994	38,526	36,766	33,647	34,476
Industrial	82,805	74,363	81,780	79,266	80,490
For Power Generation	63,024	39,639	30,875	34,096	26,099
For Resale	8,465	9,048	8,921	8,923	8,472
Total	252,615	216,874	210,251	206,004	198,656
Secondary Market Sales	46,823	46,057	53,442	42,049	40,994
Number of Customers Billed (12-month average):					
Residential	864,205	855,670	852,586	835,636	815,579
Commercial	94,287	94,404	94,045	93,472	92,692
Industrial	2,273	2,358	2,937	2,959	3,008
For Power Generation	20	20	20	15	12
For Resale	16	17	17	15	19
Total	960,801	952,469	949,605	932,097	911,310
Average Per Residential Customer:					
Gas Used - Dekatherms	67.49	64.63	60.88	59.92	60.23
Revenue	$ 860.15	$ 920.91	$ 953.61	$ 889.90	$ 1,031.23
Revenue Per Dekatherm	$ 12.74	$ 14.25	$ 15.66	$ 14.85	$ 17.12
Cost of Gas (in thousands):					
Natural Gas Commodity Costs	$ 753,529	$ 727,744	$ 1,454,073	$ 1,055,600	$ 1,229,326
Capacity Demand Charges	127,137	128,081	127,640	116,977	99,333
Natural Gas Withdrawn From (Injected Into) Storage, net	5,293	126,480	(78,283)	(12,815)	15,709
Regulatory Charges, net	113,744	94,237	32,705	27,365	56,781
Total	$ 999,703	$ 1,076,542	$ 1,536,135	$ 1,187,127	$ 1,401,149

	2010	2009	2008	2007	2006
Supply Available for Distribution (dekatherms in thousands):					
Natural Gas Purchased	157,021	149,696	159,857	143,598	140,999
Transportation Gas	147,038	115,519	108,332	108,355	101,414
Natural Gas Withdrawn From (Injected Into) Storage, net	(1,309)	1,010	(2,980)	(1,640)	(197)
Company Use	(282)	(283)	(135)	(141)	(127)
Total	302,468	265,942	265,074	250,172	242,089

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.

As of October 31, 2010, 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 East Tennessee and Transco)	36,700
NiSource-Columbia Gas (through Transco and Columbia Gulf)	42,800
NiSource-Columbia Gulf	10,000
ONEOK-Midwestern (through Tennessee, Columbia Gulf, East Tennessee and Transco)	120,000
Total	915,800

As of October 31, 2010, 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 with deliverability from 5 days to one year.

Piedmont Liquefied Natural Gas (LNG)	278,000
Pine Needle LNG (through Transco)	263,400
Williams-Transco Storage	86,100
NiSource-Columbia Gas Storage	96,400
Hardy Storage (through Columbia Gas and Transco)	68,800
Dominion Storage (through Transco)	13,200
El Paso-Tennessee Pipeline Storage	55,900
Total	861,800

As of October 31, 2010, we own or have under contract 36.2 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 and independent producers and marketers. 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 receive firm, long-term market area storage service from Hardy Storage Company, LLC, a storage facility in West Virginia, and firm, long-term transportation service from Midwestern Gas Transmission Company that provides access to gas supplies from Canadian and Rocky Mountain supply basins via the Chicago hub.

We have agreements with Progress Energy Carolinas, Inc., a subsidiary of Progress Energy, Inc., to provide natural gas delivery service to their planned power generation facilities to be built at their Wayne County, North Carolina power generation site and at their Sutton site near Wilmington, North Carolina. We also completed construction on a power generation project to provide natural gas delivery service to a Progress Energy Carolinas' power generation facility located in Richmond County, North Carolina during the first quarter of fiscal 2011. In addition to the environmental benefits associated with using natural gas at these new plants in lieu of coal, the construction of the natural gas pipelines for these projects will also add to our natural gas infrastructure in the eastern part of North Carolina and enhance future opportunities for economic growth and development. In addition, we have agreements with Duke Energy Carolinas, LLC, a subsidiary of Duke Energy Corporation, to provide natural gas delivery service to two new power generation facilities. The facility located in Rowan County, North Carolina, was placed into service during the first quarter of fiscal 2011. The Rockingham County, North Carolina, power generation facility is under construction and scheduled to be placed in service November 2011. We will continue to seek opportunities to provide long-term gas transportation service to power generation projects in our market area. For further information on our anticipated capital investment related to the construction of the natural gas pipelines to service these new power generation facilities, see "Cash Flows from Investing Activities" in Item 7 of this Form 10-K in Management's Discussion and Analysis. For further information on gas supply and regulation, see "Gas Supply and Regulatory Proceedings" in Item 7 of this Form 10-K and Note 2 to the consolidated financial statements.

We are continuing to see challenging economic conditions in our market area as evidenced by high rates of unemployment, a depressed housing market, significantly reduced new home construction and little new commercial development. In 2010, we experienced declines in residential conversions, residential new construction and in the small commercial market. However, as discussed above, we are positioning ourselves to capitalize on new opportunities as the economy slowly improves, and continue to focus on customer conversions to natural gas and power generation gas delivery service opportunities. Seeking to expand the use of natural gas, we continue to emphasize natural gas as the fuel of choice for customers, including the comfort, affordability, reliability and efficiency of natural gas, as well as reminding our customers of our reliability and safety as a company. We are forecasting gross customer addition growth for fiscal 2011 to be 1.2%.

During the year ended October 31, 2010, 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, availability and the price of alternate fuels. Under FERC policies, certain large volume customers located in proximity to the interstate pipelines delivering gas to us could 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, 2010, the City of Monroe, a wholesale customer, completed construction of a pipeline to bypass our system with a direct connection to Transco. This action had and will have no impact on our utility margin as a result of a regulatory provision approved in our last North Carolina rate case. The future level of bypass activity cannot be predicted.

The regulated utility also competes with other energy products, such as electricity and propane, in the residential and small commercial customer markets. The most significant product competition is with 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 price, value, availability, environmental attributes, comfort, convenience, reliability and energy efficiency. The direct use of natural gas in homes and businesses is the most efficient and cost effective use of natural gas and lowers the carbon footprint of those premises in our market area.

As noted above, many of our industrial 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 with natural gas historically having a price advantage over fuel oil. The relationship between supply and demand has the greatest impact on the price of natural gas. The price of oil depends upon a number of factors beyond our control, including the relationship between worldwide supply and demand and the policies of foreign and domestic governments and organizations, as well as the value of the US dollar versus other currencies. 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, 2010, our largest revenue generating customer contributed $62.7 million, or 4%, of total operating revenues. Our largest margin generating customer contributed $11.7 million, or 2% of total margin.

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

Compliance with federal, state and local environmental protection laws have had no material effect on our 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, 2010, our fiscal year end, we had 1,788 employees, compared with 1,821 as of October 31, 2009.

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

An overall economic downturn or slow economic recovery could negatively impact our earnings.

Weakening or slow recovery of economic activity in our markets could result in a loss of customers, a decline in customer additions, especially in the new home construction market, or a decline in energy consumption, which could adversely affect our revenues or restrict our future growth. It may become more difficult for customers to pay their gas bills, leading to slow collections and higher-than-normal levels of accounts receivable. This could increase our financing requirements and non-gas cost bad debt expense. Earnings and liquidity would be negatively affected, reducing our ability to grow the business.

Increases in the wholesale price of natural gas could reduce our earnings and working capital.

The supply and demand balance in natural gas markets could cause an increase in the price of natural gas. The prudently incurred 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 as well as cause new home developers, builders 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 higher than historical levels, our working capital costs could increase due to higher carrying costs of gas storage inventories, and customers may have trouble paying higher bills leading to bad debt expenses, which may reduce our earnings.

A decrease in the availability of adequate 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, operational failures or disruptions, hurricanes, tornadoes, floods, freeze off of natural gas wells, terrorist attacks or other acts of war, could reduce our normal interstate supply of gas and thereby reduce our earnings. Moreover, if additional natural gas infrastructure, including but not limited to exploration and drilling rigs and 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.

Our business is subject to competition that could negatively affect our results of operations.

The natural gas business is competitive, and we are facing increasing competition from other companies that supply energy, including electric companies, oil and propane dealers, renewable energy providers and, as it relates to sources of energy for electric power plants, coal. A significant competitive factor is price.

In residential and commercial customer markets, our natural gas distribution operations compete with other energy products, primarily electricity, fuel oil and propane. Our primary product competition is with electricity for heating, water heating and cooking. Increases in the price of natural gas or decreases in the price of other energy sources could negatively impact our competitive position by decreasing the price benefits of natural gas to the consumer. In the case of industrial customers, such as manufacturing plants, adverse economic or market conditions, including higher gas costs, could cause these customers to use alternative sources of energy or bypass our systems in favor of energy sources with lower per-unit costs.

Higher gas costs or decreases in the price of other energy sources may allow competition from alternative energy sources for applications that have traditionally used natural gas, encouraging some customers to move away from natural gas-fired equipment to equipment fueled by other energy sources. Competition between natural gas and other forms of energy is also based on efficiency, performance, reliability, safety and other non-price factors. Technological improvements in other energy sources and events that impair the public perception of these non-price attributes of natural gas could erode our competitive advantage. These factors in turn could decrease the demand for natural gas, impair our ability to attract new customers, and cause existing customers to switch to other forms of energy or to bypass our systems in favor of alternative competitive sources. This could result in slow or no customer growth and could cause customers to reduce or cease using our product, thereby reducing our ability to make capital expenditures and otherwise grow our business and adversely affecting our earnings.

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 regulatory authority over some of our operations, including sales of natural gas in the wholesale market and the purchase and sale of interstate pipeline and storage capacity. Additionally, the Commodities Futures Trading Commission under the 2010 Dodd-Frank Wall Street Reform and Consumer Protection Act has regulatory authority of the over-the-counter derivatives markets. Any federal legislation or agency legislation that has the effect of significantly raising costs that could not be recovered in rates from our customers or reducing the availability of supply or capacity, the liquidity of the natural gas supply market or our competitiveness could negatively impact our earnings.

Climate change legislation or regulations could increase our operating costs, negatively affecting our growth, cash flows and earnings.

The federal government may enact legislation that attempts to control or limit the causes of climate change, including greenhouse gas emissions such as carbon dioxide. The Environmental Protection Agency has announced plans to issue climate change regulations beginning in January 2011. These initiatives could result in various new laws or regulations. Such laws or regulations could impose operational requirements, impose additional charges to fund energy efficiency activities, provide a cost advantage to alternative energy sources other than natural gas, impose costs or restrictions on end users of natural gas, or result in other costs or requirements. As a result, there is a possibility that, if enacted or adopted, such legislation or regulation could put upward pressure on the cost of natural gas relative to other energy sources, increase our costs and impact the competitive position of natural gas, negatively affecting our growth opportunities, cash flows and earnings.

Regulatory actions at the state level could impact our ability to earn a reasonable rate of return on our invested capital and to fully recover our operating costs as well as reduce our 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. We monitor allowed rates of return and our ability to earn appropriate rates of return based on factors, such as increased operating costs, and initiate general rate proceedings as needed. If a state regulatory commission were to prohibit us from setting rates that allow for the timely recovery of 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 and cost of gas) or other tariff provisions, then our earnings could be negatively impacted. In the normal course of business in the regulatory environment, assets are placed in service before rate cases can be filed that could result in an adjustment of our returns. Once rate cases are filed, regulatory bodies have the authority to suspend implementation of the new rates while studying the cases. Because of this process, we may suffer the negative financial effects of having placed in service assets that do not initially earn our authorized rate of return without the benefit of rate relief, which is commonly referred to as "regulatory lag." Rate cases also involve a risk of rate reduction, because once rates have been filed, they are still subject to challenge for their reasonableness by various appropriate entities. Regulatory authorities may also review whether our gas cost purchases are prudent and can adjust the amount of our gas costs that we pass through to our customers. Additionally, our state regulators 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 results of operations, financial condition and cash flows. Our debt and equity financings are also subject to regulation by the NCUC. Delays or failure to receive NCUC approval could limit our ability to access or take advantage of changes in the capital markets. This could negatively impact our liquidity or earnings.

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 normalize our margin for weather during the winter, providing for an adjustment up or down, to take into account warmer-than-normal or colder-than-normal weather. Mild winter temperatures can cause a decrease in the amount of gas we sell and deliver in any year and the margin we collect from these customers. If our rates and tariffs were modified to eliminate weather protection, such as weather normalization and rate decoupling tariffs, then we would be exposed to significant risk associated with weather, and our earnings could vary as a result.

Our gas supply risk management programs are subject to state regulatory approval or annual review in gas cost proceedings.

We manage our gas supply costs through short-term and long-term procurement and storage contracts. In the normal course of business, we utilize New York Mercantile Exchange (NYMEX) exchange traded instruments of various durations for the forward purchase or sale of our natural gas requirements, subject to regulatory approval or review. As a component of our gas costs, these expenses are subject to regulatory approval, and we may be exposed to additional liability if the recovery of these costs of gas supply procurement or risk management activities is excluded by our regulators in gas cost recovery proceedings.

Operational interruptions to our gas distribution activities caused by accidents, work stoppage, severe weather conditions, including destructive weather patterns such as hurricanes, tornadoes and floods, pandemic or acts of terrorism could adversely impact earnings.

Inherent in our gas distribution activities are a variety of hazards and operational risks, such as leaks, ruptures, mechanical problems and third party excavation damage. Severe weather conditions, as well as acts of terrorism, can also damage our pipelines and other infrastructure and disrupt our ability to conduct our natural gas distribution and transportation business. Pandemic could result in a significant part of our workforce being unable to operate or maintain our infrastructure or perform other tasks necessary to conduct our business. If the foregoing events are severe enough or if they lead to operational interruptions, they 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. Our regulators may not allow us to recover part or all of the increased cost related to the foregoing events from our customers, which would negatively affect our earnings. With part of our workforce represented by unions, we are exposed to the risk of a work stoppage. The occurrence of any of these events could adversely affect our financial position, results of operations and cash flows.

We may not be able to complete necessary or desirable infrastructure development projects, which may delay or prevent us from expanding our business.

In order to serve new customers or expand our service to existing customers, we often need to expand or upgrade our distribution, transmission and/or storage infrastructure, including laying new pipeline and building compressor stations or LNG storage tanks. Various factors may prevent or delay us from completing such projects or make completion more costly, such as the inability to obtain required approval from local, state and/or federal regulatory and governmental bodies, public opposition to the project, inability to obtain adequate financing, construction delays, cost overruns, and inability to negotiate acceptable agreements relating to rights-of-way, construction or other material development components. As a result, we may not be able to adequately support customer growth, which would negatively impact our earnings.

A downgrade in our credit rating could negatively affect our cost of and ability to access capital.

Our ability to obtain adequate and cost effective financing depends on our credit ratings. A negative change in our ratings outlook or any downgrade in our current investment-grade credit ratings by our rating agencies, particularly below investment grade, could adversely affect our cost of borrowing and/or access to sources of liquidity and capital. Such a downgrade could further limit our access to private credit markets and increase the costs of borrowing under available credit lines. Should our credit ratings be downgraded, the interest rate on our borrowings under our revolving credit agreement would increase. An increase in borrowing costs without the ability to recover these higher costs in the rates charged to our customers could adversely affect earnings by limiting our ability to earn our allowed rate of return.

The inability to access capital or significant increases in the cost of capital could adversely affect our business.

Our ability to obtain adequate and cost effective financing is dependent upon the liquidity of the financial markets, in addition to our credit ratings. Disruptions in the capital and credit markets could adversely affect our ability to access short-term and long-term capital. Our access to funds under short-term credit facilities is dependent on the ability of the participating banks to meet their funding commitments. Those banks may not be able to meet their funding commitments if they experience shortages of capital and liquidity. Longer disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant financial institutions could adversely affect our access to capital needed for our business. The inability to access adequate capital may require us to conserve cash, prevent or delay us from making capital expenditures, and require us to reduce or eliminate the dividend or other discretionary uses of cash.

Changes in federal and state fiscal and monetary policy could significantly increase our costs or decrease our cash flows.

Changes in federal and state fiscal and monetary policy may result in increased taxes, interest rates, and inflationary pressures on the costs of goods and services. This could increase our expenses and decrease our earnings if we are not able to recover such increased costs from our customers. This series of events may increase our rates to customers and thus may negatively impact customer billings and customer growth. Changes in accounting or tax rules, such as accelerated tax depreciation, could negatively affect our cash flow. Any of these events may cause us to increase debt, conserve cash, negatively affect our ability to make capital expenditures to grow the business or require us to reduce or eliminate the dividend or other discretionary uses of cash, and could negatively affect earnings.

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 also purchase natural gas for storage. 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 profitability. Volatility in gas prices may require us to post cash collateral as part of our regulated gas price hedging program. 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 open market. Our dependency on external sources of financing creates the risk that our profits could decrease as a result of higher borrowing 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.

Volatility in seasonal cash flow requirements, including requirements for our gas supply procurement and risk management programs, may require increased levels of borrowing that could result in non-compliance with the debt-to-equity ratios in our credit facilities as well as cause a credit rating downgrade. Any disruptions in the capital and credit markets could require us to conserve cash until the markets stabilize or until alternative credit arrangements or other funding required for our needs can be secured. Such measures could cause deferral of major capital expenditures, changes in our gas supply procurement and risk management programs, the reduction or elimination of the dividend payment or other discretionary uses of cash.

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 revolving 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, which would negatively affect our ability to implement our business plan, make capital expenditures and finance our operations.

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 to fulfill their contractual obligations on a timely basis. Any delay or default in payment or failure of the counterparties to meet their contractual obligations 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 for the non-contributory defined benefit pension plan are 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, changes in these actuarial assumptions, future government regulation and our required or voluntary contributions made to the plan. A significant decline in the value of investments that fund our pension plan, if not offset or mitigated by a decline in our liabilities, may significantly differ from or alter the values and actuarial assumptions used to calculate our future pension expense. A decline in the value of these investments could increase the expense of our pension plan, and 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. Additionally, the discovery of presently unknown environmental conditions could give rise to expenditures and liabilities, including fines or penalties, which could have a material adverse effect on our business, results of operations or financial condition.

We are subject to new and existing pipeline safety and system integrity laws and regulations that may require significant expenditures or significantly increase operating costs.

We are subject to existing and may be subject to new pipeline safety and system integrity laws and regulations affecting various aspects of our present and future operations. These laws and regulations generally require us to enhance pipeline safety and system integrity by identifying and reducing pipeline risks. Compliance with these laws and regulations may result in increased capital, operating and other costs which may not be recoverable in rates from our customers. Furthermore, because the language in some of these laws and regulations is not prescriptive, there is a risk that an incorrect or inadequate interpretation of these laws and regulations may lead to a failure to comply. Such a failure for this or other reasons may result in fines, penalties or injunctive measures. All of the above could result in a material adverse effect on our business, results of operations or financial condition.

We may invest in companies that have risks that are inherent in their businesses, and these risks may negatively affect our earnings from those companies.

We are invested in several natural gas related businesses as an equity method investor. One of these businesses is not directly regulated by state or federal regulatory bodies and could be subject to adverse market conditions not experienced by the regulated utility segment. These businesses could be subject to laws, regulations or market conditions, or have risks inherent in their operations, that adversely affect their performance. We do not control the operations of these businesses, and thus management of these businesses could make decisions that adversely impact their performance. All the foregoing could adversely affect our earnings from or return of our investment in these businesses. We could make future investments in similarly unregulated businesses that have the similar potential to adversely affect our earnings from or return of our investment in those businesses. All these adverse impacts could negatively affect our results of operations or financial condition.

Our inability to attract and retain professional and technical employees could adversely 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 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 93% of the total invested in utility distribution and transmission plant to serve our customers. We have approximately 2,600 miles of transmission 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 28,900 miles (three-inch equivalent) of distribution mains. The transmission pipelines and distribution mains are generally underground, located near public streets and highways, or on property owned by others, for which we have obtained the necessary legal rights to place and operate our facilities on such 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 except for "Plant held for future use" as classified in our consolidated balance sheets. The amount classified as plant held for future use relates to expenditures associated with the Robeson County LNG facility. We have delayed proceeding with work on the Robeson LNG facility given the slowing of our growth due to current economic conditions and because the Sutton facilities will help serve our near term system pressure requirements in a cost effective manner in the eastern part of North Carolina. The timing and design scope of expansion of our facilities in this area will be determined as our system infrastructure and market supply growth requirements in North Carolina dictate.

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 $4.7 million for the year ended October 31, 2010.

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 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 immaterial litigation in the normal course of business.

Item 4. (Removed and Reserved).

PART II

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

Market Information

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, 2010 and 2009.

2010	High	Low	2009	High	Low
Quarter ended:			Quarter ended:		
January 31	$ 27.84	$ 22.51	January 31	$ 33.92	$ 24.77
April 30	28.52	23.87	April 30	27.55	20.68
July 31	27.97	24.50	July 31	25.50	21.65
October 31	29.85	26.15	October 31	25.87	23.10

Holders

As of December 17, 2010, our common stock was owned by 14,260 shareholders of record. Holders of record exclude the individual and institutional security owners whose shares are held in street name or in the name of an investment company.

Dividends

The following table provides information with respect to quarterly dividends paid on common stock for the years ended October 31, 2010 and 2009. We expect that comparable cash dividends will continue to be paid in the future.

2010	Dividends Paid Per Share	2009	Dividends Paid Per Share
Quarter ended:		Quarter ended:	
January 31	27¢	January 31	26¢
April 30	28¢	April 30	27¢
July 31	28¢	July 31	27¢
October 31	28¢	October 31	27¢

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, 2010, net earnings available for restricted payments were greater than retained earnings; therefore, our retained earnings were not restricted.

Sale of Unregistered Securities

On November 16, 2009, we discovered in our fiscal 2009 and early fiscal 2010 that we had inadvertently sold more shares under our dividend reinvestment and stock purchase plan (DRIP) than were registered with the Securities and Exchange Commission (SEC) and authorized by our Board of Directors for issuance under the DRIP. We also discovered that the registration statement we believed had registered shares issued under the DRIP between December 1, 2008 and November 16, 2009 had expired for some of those shares. As a result, from November 1, 2009 through November 16, 2009, we sold 15,029 shares under the DRIP that may not have been registered at the time of issuance for proceeds of $347,000. Our Board of Directors ratified the authorization and issuance of the excess number of shares, and on November 20, 2009, we filed a registration statement covering the sale and issuance of an additional 2.75 million shares of our common stock under the DRIP. On February 8, 2010, we filed a registration statement (Rescission Offer) which offered to rescind the purchase of the shares sold under the DRIP between December 1, 2008 and November 16, 2009 and registered all previously unregistered shares issued under the DRIP during that period. Under the Rescission Offer, the purchase of 711 shares was rescinded for an aggregate consideration of $18,900. We incurred costs related to the Rescission Offer of $.8 million, which have been recorded against retained earnings. We reported these events to the relevant regulatory authorities, including the SEC and the North Carolina Utilities Commission (NCUC). The sale of unregistered securities could subject us to enforcement actions or penalties and fines by these regulatory authorities, though no such regulatory action has been initiated. While we are unable to predict the full consequences of these events, we do not expect them to have a material adverse effect on us.

Share Repurchases

The following table provides information with respect to repurchases of our common stock under the Common Stock Open Market Purchase Program during the three months ended October 31, 2010.

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 (1)
Beginning of the period					4,510,074
8/1/10 - 8/31/10	-		$ -	-	4,510,074
9/1/10 - 9/30/10	10,103	(2)	$ 27.93	-	4,510,074
10/1/10 - 10/31/10	-		$ -	-	4,510,074
Total	10,103		$ 27.93	-	

(1) The Common Stock Open Market Purchase Program was approved by the Board of Directors and announced on June 4, 2004 to purchase up to three million shares of common stock for reissuance under our dividend reinvestment and stock purchase, employee 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. The additional four million shares were referred to as our accelerated share repurchase (ASR) program with an expiration date of December 31, 2010. On March 6, 2009, the Board of Directors authorized the repurchase of up to an additional four million shares under the Common Stock Open Market Purchase Program and the ASR program, which were consolidated.

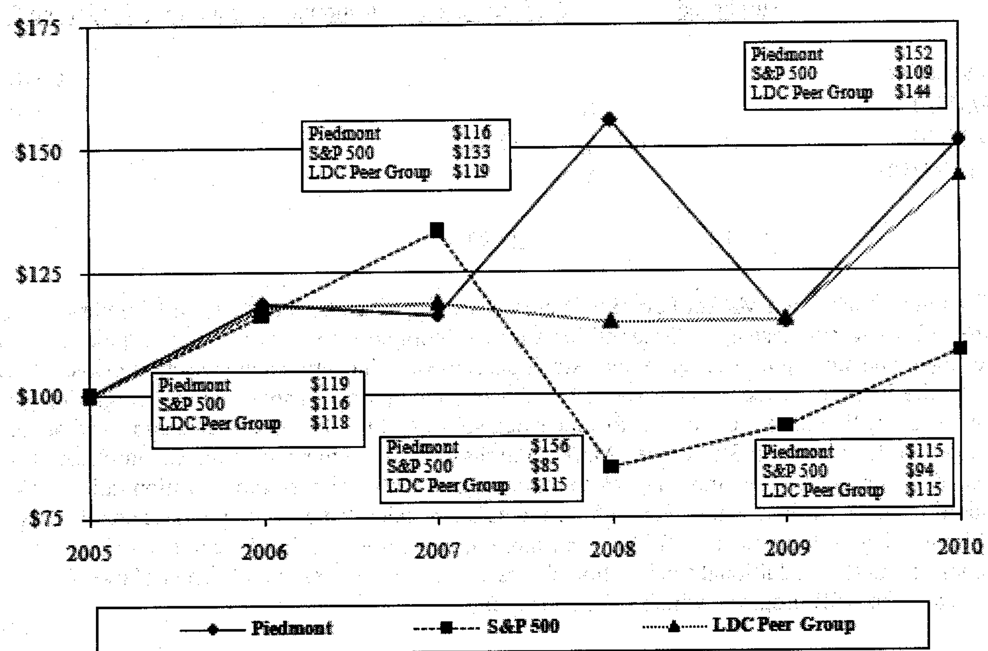
(2) The total number of shares purchased is shares withheld by us to satisfy tax withholding obligations related to the vesting of shares of restricted stock under an incentive compensation plan, which are outside of the Common Stock Open Market Purchase Program.

Comparisons of Cumulative Total Shareholder Returns

The following performance graph compares our cumulative total shareholder return from October 31, 2005 through October 31, 2010 (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 our 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, 2005 and that all dividends were reinvested. Stock price performances shown on the graph are not indicative of future price performance.

Comparisons of Five-Year Cumulative Total Returns
Value of $100 Invested as of October 31, 2005



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

Item 6. Selected Financial Data

The following table provides selected financial data for the years ended October 31, 2006 through 2010.

In thousands except per share amounts	2010	2009	2008	2007	2006
Operating Revenues	$ 1,552,295	$ 1,638,116	$ 2,089,108	$ 1,711,292	$ 1,924,628
Margin (operating revenues less cost of gas)	$ 552,592	$ 561,574	$ 552,973	$ 524,165	$ 523,479
Net Income	$ 141,954	$ 122,824	$ 110,007	$ 104,387	$ 97,189
Earnings per Share of Common Stock:					
Basic	$ 1.96	$ 1.68	$ 1.50	$ 1.41	$ 1.28
Diluted	$ 1.96	$ 1.67	$ 1.49	$ 1.40	$ 1.28
Cash Dividends per Share of Common Stock	$ 1.11	$ 1.07	$ 1.03	$ 0.99	$ 0.95
Total Assets *	$ 3,053,275	$ 3,118,819	$ 3,138,401	$ 2,823,106	$ 2,743,826
Long-Term Debt (less current maturities)	$ 671,922	$ 732,512	$ 794,261	$ 824,887	$ 825,000

* Total assets for the years 2006 through 2008 have been adjusted to reflect the gross presentation rather than a net presentation in accordance with the adoption of new accounting guidance related to offsetting of amounts related to certain contracts with the same counterparty.

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 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 ability to earn appropriate rates of return and initiate general rate proceedings as needed.

- Residential, commercial, industrial and power generation growth and energy consumption in our service areas. The ability to retain and grow our customer base, the pace of that growth and the levels of energy consumption 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.

- 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.

- 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 and the ability to complete these capital projects may be affected by the ability to obtain and the cost of obtaining governmental approvals, compliance with federal and state pipeline safety and integrity regulations, cost and timing of project development-related contracts, project development delays and the cost and availability of labor and materials. Weather, general economic conditions and the cost of funds to finance our capital projects can materially alter the cost and timing of a project.

- Access to capital markets. 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 in our financial condition or in the financial condition of our lenders or investors 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, regulatory 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. Since such risks may affect the availability and cost of natural gas, they also may affect the competitive position of natural gas relative to other energy sources.

- 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, tornadoes and floods, can impact our customers, our suppliers and the pipelines that deliver gas to our distribution system and our distribution and transmission assets. Weather conditions directly influence the supply, demand, distribution and cost of natural gas.

- Changes in environmental, safety, system integrity, tax and other laws and regulations, including those related to climate change, and the cost of compliance. We are subject to extensive federal, state and local laws and regulations. Compliance with such laws and regulations could increase capital or operating costs, affect our reported earnings, increase our liabilities or change the way our business is conducted.

- 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, and 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 these risks may negatively affect our earnings from those companies.

- Changes in outstanding shares. The number of outstanding shares may fluctuate due to new issuances or repurchases under our Common Stock Open Market Purchase Program.

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," "anticipate," "intend," "should," "could," "will," "assume," "can," "estimate," "forecast," "future," "indicate," "outlook," "plan," "predict," "seek," "target," "would" 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.

Executive Overview

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, industrial and power generation customers in portions of North Carolina, South Carolina and Tennessee, including 51,600 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, 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.

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

We have two reportable business segments, regulated utility and non-utility activities. The regulated utility segment is the largest segment of our business with approximately 97% of our consolidated assets. Factors critical to the success of the regulated utility segment include operating 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 2010, our earnings before taxes, including the gain from the sale of half of our ownership interest in SouthStar Energy Services LLC (SouthStar) of $49.7 million, were $205.6 million, 67% of which 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 and regulated interstate natural gas storage and intrastate natural gas transportation. For 2010, the earnings before taxes from our non-utility activities segment, including the gain from the sale of half of our ownership in SouthStar was 33%, with 4% from regulated non-utility activities and 29% from unregulated non-utility activities.

The generally accepted accounting principles (GAAP) presentation does not adequately reflect our segments because of the inclusion of the gain from the sale of half of our ownership interest in SouthStar, which is in our non-utility activities segment. Excluding this gain for 2010, 85% of our earnings before taxes came from our regulated utility segment, and earnings before taxes from our non-utility activities segment was 15%, with 5% from regulated non-utility activities and 10% from unregulated non-utility activities.

For further information on business segments, see Note 12 to the consolidated financial statements. For information about our equity method investments, see Note 11 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. The NCUC also regulates us 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 Federal Energy Regulatory Commission (FERC) that affect the purchase and sale of and the prices paid for the interstate transportation and storage of natural gas, regulations of the Department of Transportation that affect the design, construction, operation, maintenance, integrity, safety and security of natural gas distribution and transmission systems, and regulations of the Environmental Protection Agency relating to the environment. 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.

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 on invested capital for our shareholders. In North Carolina, a margin decoupling mechanism provides for the recovery of our approved margin from residential and commercial customers independent of consumption patterns. The margin decoupling mechanism results in semi-annual rate adjustments to refund any over-collection of margin or recover any under-collection of margin. We have weather normalization adjustment (WNA) mechanisms in South Carolina and Tennessee that partially offset the impact of colder- 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 increases revenues when weather is warmer than normal and decreases 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 margin decoupling mechanism or the WNA. For further information, see Note 2 to the consolidated financial statements.

Our strategic focus is 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 responsibly manage our gas distribution business through control of our operating costs, implementation of new technologies and sound rate and regulatory initiatives. To enhance the value and growth of our utility assets, we focus on the sound management of our capital spending, looking at projects and initiatives that will improve service for current customers and provide profitable customer growth opportunities in our service areas with an appropriate return on invested capital. 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.

Our capital plan includes maintaining 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.

We continue to work toward a business model that positions us for long-term success in a low-carbon energy economy with a focus on future growth opportunities as there continues to be attention at the national level with climate change legislation and impending regulation in 2011 by the Environmental Protection Agency. We are seeking opportunities for regulatory innovation and strategic alliances to advance our customers' interests in energy conservation and efficiency and environmental stewardship. We are continually reviewing our business processes for quality and efficiency with a concentration on customer-oriented process improvements to be in a position to seize future business opportunities.

We continually assess alternative rate structures and cost recovery mechanisms that are more appropriate to the changing energy economy. We have been pursuing alternatives to the traditional utility rate design that provide for the collection of margin revenue based on volumetric throughput with new rate designs and incentives that allow utilities to encourage energy efficiency and conservation. By breaking the link between energy consumption and margin revenues, or decoupling as we say, utilities' interests are aligned with customers' interests around conservation and energy efficiency. In North Carolina, we have decoupled rates. In South Carolina, we operate under a rate stabilization mechanism that achieves the objectives of margin decoupling with a one-year lag. Earlier this year, the TRA denied our filing to decouple residential rates without prejudice to us refiling for a decoupled rate structure in a future general rate proceeding. For 2010, these rate designs have stabilized our gas utility margin by providing fixed recovery of 71% of our utility margins, including margin decoupling in North Carolina, facilities charges to our customers and fixed-rate contracts; semi-fixed recovery of 18% of our utility margins, including the rate stabilization mechanism in South Carolina and WNA in South Carolina and Tennessee; and volumetric or periodic renegotiation of 11% of our utility margins. For 2010, the margin decoupling mechanism in North Carolina reduced margin by $5.9 million, and the WNA in South Carolina and Tennessee reduced margin by $8.8 million.

We will continue our efforts to promote the direct use of natural gas in more homes, businesses, industries and vehicles. We continue to believe that the expanded use of domestic natural gas can help revitalize our economy, reduce both overall greenhouse gas emissions and energy consumption and enhance our national energy security. With the success of on-shore drilling and completion technologies, recent production of domestic natural gas supplies from shale formations has resulted in an increase of domestic gas supply, which in turn has contributed to a moderation in the price of gas. This price moderation has made natural gas more competitive against other fuels.

We have agreements with Progress Energy Carolinas, Inc., a subsidiary of Progress Energy, Inc., to provide natural gas delivery service to their planned power generation facilities to be built at their Wayne County, North Carolina power generation site and at their Sutton site near

Wilmington, North Carolina. We also completed construction on a power generation project to provide natural gas delivery service to a Progress Energy Carolinas' power generation facility located in Richmond County, North Carolina during the first quarter of fiscal 2011. In addition to the environmental benefits associated with using natural gas at these new plants in lieu of coal, the construction of the natural gas pipelines for these projects will also add to our natural gas infrastructure in the eastern part of North Carolina and enhance future opportunities for economic growth and development. In addition, we have agreements with Duke Energy Carolinas, LLC, a subsidiary of Duke Energy Corporation, to provide natural gas delivery service to two new power generation facilities. The facility located in Rowan County, North Carolina, was placed into service during the first quarter of fiscal 2011. The Rockingham County, North Carolina, power generation facility is under construction and scheduled to be placed in service November 2011. We will continue to seek opportunities to provide long-term gas transportation service to power generation projects in our market area. See the following discussion of our anticipated capital investment related to the construction of the natural gas pipelines to service these new power generation facilities in "Cash Flows from Investing Activities" in Item 7 of this Form 10-K in Management's Discussion and Analysis.

We are continuing to see challenging economic conditions in our market area as evidenced by high rates of unemployment, a depressed housing market, significantly reduced new home construction and little new commercial development. As discussed above, we are positioning ourselves to capitalize on new opportunities as the economy slowly improves, and continue to focus on customer conversions to natural gas and power generation gas delivery service opportunities. Seeking to expand the use of natural gas, we continue to emphasize natural gas as the fuel of choice for customers, including the comfort, affordability, reliability and efficiency of natural gas, as well as reminding our customers of our reliability and safety as a company. We are forecasting gross customer addition growth for fiscal 2011 to be 1.2%.

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 our core competencies. We analyze and evaluate potential projects with a major factor being a projected rate of return at least equal to the returns allowed in our utility operations based on the risk of such projects. We participate in the governance of our ventures by having management representatives on the governing boards. We monitor actual performance against expectations, and any decision to exit an existing joint venture would be based on many factors, including performance results and continued alignment with our business strategies. On January 1, 2010, we sold half of our 30% interest in SouthStar to Georgia Natural Gas Company (GNGC), a subsidiary of AGL Resources, Inc., for $57.5 million. For further information, see Note 11 to the consolidated financial statements.

In March 2010, President Obama signed into law the "Patient Protection and Affordable Care Act" and the "Health Care and Education Act of 2010." These health care reform laws require regulatory agencies to issue new regulations implementing many provisions of the laws with a phase in over an eight-year period. We have changed the design of our health care plan in order to comply with provisions that have already gone into effect or will be going into effect in 2011, such as eliminating lifetime maximums on benefits, extending coverage of dependent children to age 26 and including all costs of preventive coverage. While we are not able to assess the full impact of these laws until the implementing regulations have been adopted, based on the information available to us at this time, we do not expect these laws to have a material adverse impact on our financial position, results of operations or cash flows.

In July 2010, the "Dodd-Frank Wall Street Reform and Consumer Protection Act" (Dodd-Frank Act) was enacted, representing an overhaul of the framework for regulation of U.S. financial markets. The Dodd-Frank Act calls for various regulatory agencies, including the SEC and the Commodities Futures Trading Commission, to establish regulations for implementation of many of the provisions of the Dodd-Frank Act, and we anticipate that these new regulations will provide additional clarity regarding the extent of the impact of this legislation on us. We expect to be able to continue to participate in financial markets for the purchase of our financial price hedging options under our gas supply hedging programs. However, the costs of doing so may be increased as a result of the new legislation. We may also incur additional costs associated with our compliance with the new regulations and anticipated additional reporting and disclosure obligations. While we are not able to assess the full impact of the Dodd-Frank Act until all the implementing regulations have been adopted, based on the information available to us at this time, we do not believe provisions of the regulations implementing the Dodd-Frank Act will have a material adverse effect on our financial position, results of operations or cash flows.

Results of Operations

The following tables present our financial highlights for the years ended October 31, 2010, 2009 and 2008.

Income Statement Components

In thousands except per share amounts	2010	2009	2008	Percent Change 2010 vs. 2009	Percent Change 2009 vs. 2008
Operating Revenues	$ 1,552,295	$ 1,638,116	$ 2,089,108	(5.2)%	(21.6)%
Cost of Gas	999,703	1,076,542	1,536,135	(7.1)%	(29.9)%
Margin	552,592	561,574	552,973	(1.6)%	1.6 %
Operations and Maintenance	219,829	208,105	210,757	5.6 %	(1.3)%
Depreciation	98,494	97,425	93,121	1.1 %	4.6 %
General Taxes	33,909	34,590	33,170	(2.0)%	4.3 %
Income Taxes	62,082	70,079	62,814	(11.4)%	11.6 %
Total Operating Expenses	414,314	410,199	399,862	1.0 %	2.6 %
Operating Income	138,278	151,375	153,111	(8.7)%	(1.1)%
Other Income (Expense), net of tax	47,387	18,124	16,169	161.5 %	12.1 %
Utility Interest Charges	43,711	46,675	59,273	(6.4)%	(21.3)%
Net Income	$ 141,954	$ 122,824	$ 110,007	15.6 %	11.7 %
Average Shares of Common Stock:					
Basic	72,275	73,171	73,334	(1.2)%	(0.2)%
Diluted	72,525	73,461	73,612	(1.3)%	(0.2)%
Earnings per Share of Common Stock:					
Basic	$ 1.96	$ 1.68	$ 1.50	16.7 %	12.0 %
Diluted	$ 1.96	$ 1.67	$ 1.49	17.4 %	12.1 %

Gas Deliveries, Customers, Weather Statistics and Number of Employees

	2010	2009	2008	Percent Change 2010 vs. 2009	Percent Change 2009 vs. 2008
Deliveries in Dekatherms (in thousands):					
Sales Volumes	105,583	110,379	110,801	(4.3)%	(0.4)%
Transportation Volumes	147,032	106,495	99,450	38.1 %	7.1 %
Throughput	252,615	216,874	210,251	16.5 %	3.2 %
Secondary Market Volumes	46,823	46,057	53,442	1.7 %	(13.8)%
Customers Billed (at period end)	946,785	937,962	935,724	0.9 %	0.2 %
Gross Customer Additions	10,975	12,608	20,506	(13.0)%	(38.5)%
Degree Days					
Actual	3,535	3,413	3,195	3.6 %	6.8 %
Normal	3,321	3,324	3,358	(0.1)%	(1.0)%
Percent colder (warmer) than normal	6.4 %	2.7 %	(4.9)%	n/a	n/a
Number of Employees (at period end)	1,788	1,821	1,833	(1.8)%	(0.7)%

Net Income

Net income increased $19.1 million in 2010 compared with 2009 primarily due to the following changes, which increased net income:

- $49.7 million gain on sale of interest in equity method investment.
- $3 million decrease in utility interest charges.
- $.9 million decrease in non-operating expense.
- $.7 million decrease in general taxes.
- $.6 million decrease in charitable contributions.
- $.6 million increase in non-operating income.

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

- $11.7 million increase in operations and maintenance expenses.
- $10 million increase in income taxes.
- $9 million decrease in margin (operating revenues less cost of gas).
- $4.6 million decrease in income from equity method investments.
- $1.1 million increase in depreciation.

Net income increased $12.8 million in 2009 compared with 2008 primarily due to the following changes, which increased net income:

- $12.6 million decrease in utility interest charges.
- $8.6 million increase in margin.
- $5.7 million increase in income from equity method investments.
- $2.7 million decrease in operations and maintenance expenses.

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

- $8.4 million increase in income taxes.
- $4.3 million increase in depreciation.
- $2.7 million decrease in net other income (expense) items.
- $1.4 million increase in general taxes.

Operating Revenues

Operating revenues in 2010 decreased $85.8 million compared with 2009 primarily due to the following decreases:

- $65.4 million of gas costs primarily from lower total gas costs passed through to sales customers.
- $11.9 million from decreased revenues under the margin decoupling mechanism. As discussed in "Financial Condition and Liquidity," the margin decoupling mechanism in North Carolina adjusts for variations in residential and commercial use per customer, including those due to conservation and weather.
- $7.6 million from decreased revenues under the WNA in South Carolina and Tennessee.

These decreases were partially offset by the following increases:

- $3.7 million from revenues in secondary market transactions due to increased activity. Secondary market transactions consist of off-system sales and capacity release arrangements and are part of our regulatory gas supply management program with regulatory-approved sharing mechanisms between our utility customers and our shareholders.
- $1.2 million increase from volumes delivered to transportation customers.

Operating revenues in 2009 decreased $451 million compared with 2008 primarily due to the following decreases:

- $294.7 million from revenues in secondary market transactions due to decreased activity and gas costs.
- $112.1 million primarily from lower gas costs passed through to sales customers.
- $19.4 million from revenues under the margin decoupling mechanism.
- $12.7 million of commodity gas costs from volume deliveries to sales customers.
- $8 million from revenues under the WNA in South Carolina and Tennessee.
- $5.4 million from a decrease in volumes delivered to transportation customers other than power generation.

Cost of Gas

Cost of gas in 2010 decreased $76.8 million compared with 2009 primarily due to $131.1 million from lower priced gas costs passed through to sales customers, partially offset by the following increases:

- $31.7 million of commodity gas costs from increased volume deliveries to sales customers.
- $4.8 million from commodity gas costs in secondary market transactions due to increased activity.

Cost of gas in 2009 decreased $459.6 million compared with 2008 primarily due to the following decreases:

- $294.2 million from commodity gas costs in secondary market transactions due to decreased activity and gas costs.
- $127.2 million from lower gas costs passed through to sales customers.
- $12.7 million of commodity gas costs from volume deliveries to sales customers.

In all three states, we are authorized to recover from customers all prudently incurred gas costs. Changes to cost of gas are based on the amount recoverable under approved rate schedules. The net of any over- or under-recoveries of gas costs are reflected in a regulatory deferred account and are added to or deducted from cost of gas and are included in "Amounts due from customers" or "Amounts due to customers" in the consolidated balance sheets.

Margin

Our utility margin is defined as natural gas revenues less natural gas commodity purchases and fixed gas costs for transportation and storage capacity. Margin, rather than revenues, is used by management to evaluate utility operations due to the passthrough of changes in wholesale commodity prices, which accounted for 49% of revenues for the twelve months ended October 31, 2010, and transportation and storage costs, which accounted for 8%.

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.

Our utility margin is also impacted 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 (TIP) in Tennessee, margin decoupling mechanism in North Carolina and negotiated loss treatment 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 decreased $9 million in 2010 compared with 2009 primarily due to the following decreases:

- $6.6 million from net adjustments to gas costs, accounts payable and lost and unaccounted for gas.
- $1.1 million from decreased volatility in secondary market transactions.

- $1 million from our residential and commercial markets, primarily due to a $3 million negative impact of warmer weather in the non-weather normalized months of April and October, partially offset by customer growth.

Margin increased $8.6 million in 2009 compared with 2008 primarily due to an increase of $15.7 million from increased rates approved in the North Carolina general rate case effective November 1, 2008.

This increase was partially offset by the following decreases:

- $4.7 million from net adjustments to gas costs, inventory, supplier refunds and lost and unaccounted for gas due to regulatory gas cost reviews.
- $2.9 million from decreased volumes delivered to industrial customers.

Operations and Maintenance Expenses

Operations and maintenance expenses increased $11.7 million in 2010 compared with 2009 primarily due to the following increases:

- $4.2 million in payroll expense primarily from increases in long-term incentive plan accruals priced at a higher current stock price and merit wage increases for non-officer employees.
- $3.3 million in employee benefits expense due primarily to increases in pension expense from a lower discount rate used to determine periodic benefit cost and group insurance expense from higher claims.
- $2.4 million in contract labor for contract billing services, telecom and activity related to a new corporate rebranding campaign.
- $.9 million in advertising and sales promotion related to a new corporate rebranding campaign.

Operations and maintenance expenses decreased $2.7 million in 2009 compared with 2008 primarily due to the following decreases:

- $3.6 million in employee benefits expense due to reductions in pension expense resulting from changes in the discount rate and plan design, regulatory deferral of the Tennessee portion of the annual plan funding and lower group insurance expense from claims experience, and fewer employees.
- $1.4 million in contract labor for contract billing services, telecom and financial, gas accounting and compliance systems.

These decreases were partially offset by an increase of $2.7 million in regulatory amortization expense.

Depreciation

Depreciation expense increased from $93.1 million to $98.5 million over the three-year period 2008 to 2010 primarily due to increases in plant in service.

General Taxes

General taxes decreased by an insignificant amount in 2010 compared with 2009.

General taxes increased $1.4 million in 2009 compared with 2008 primarily due to increases in property taxes related to a larger property tax base and reassessments.

Other Income (Expense)

Other Income (Expense) is comprised of income from equity method investments, gain on sale of interest in equity method investment, non-operating income, charitable contributions, non-operating expense and income taxes related to these items. Non-operating income includes non-regulated merchandising and service work, home warranty programs, subsidiary operations, interest income and other miscellaneous income. Non-operating expense is comprised of other miscellaneous expenses.

The primary changes to Other Income (Expense) were in income from equity method investments and the gain on the sale of half of our ownership interest in SouthStar. All other changes were not significant.

On January 1, 2010, we sold half of our 30% membership interest in SouthStar to the other member of the joint venture and retained a 15% earnings and membership interest after the sale. The pre-tax gain on the sale was $49.7 million. The after-tax gain was $30.3 million, or $.42 per diluted earnings per share, for 2010.

Income from equity method investments decreased $4.6 million in 2010 compared with 2009 due to a $4.5 million decrease in earnings from SouthStar primarily due to the recording of earnings at the new 15% ownership interest as of January 1, 2010 and a change in the retail pricing mix chosen by SouthStar customers with a decrease in the average number of customers, losses on weather derivatives and a decreased contribution from storage and transportation asset management due to higher transportation and commodity prices, partially offset by increased average customer usage due to colder weather, favorable changes in the lower of cost or market storage inventory adjustments and higher retail price spreads.

Income from equity method investments increased $5.7 million in 2009 compared with 2008 primarily due to an increase of $6.3 million in earnings from SouthStar largely due to higher contributions from the management of storage and transportation assets, margin impacts from lower of cost or market inventory adjustments, higher operating margins in Ohio, a 2008 pricing settlement with the Georgia Public Service Commission and increased average customer usage, partially offset by a change in retail pricing plan mix and a decrease in the average number of customers.

Utility Interest Charges

Utility interest charges decreased $3 million in 2010 compared with 2009 primarily due to the following changes:

- $9.1 million increase in net interest expense due to a decrease in interest charged on amounts due from customers (receivable), which earn a carrying charge, as those balances were lower in the current period.

- $7.7 million decrease in interest expense due to an increase in the borrowed allowance for funds used during construction (AFUDC), which is recorded as income, primarily due to increased construction expenditures.
- $2.4 million decrease in interest expense on long-term debt primarily due to lower amounts of debt outstanding.
- $1.8 million decrease in interest expense on short-term debt primarily due to lower levels of borrowing in the current period combined with an average interest rate for the current period approximately 35 basis points lower than the prior year period.

Utility interest charges decreased $12.6 million in 2009 compared with 2008 primarily due to the following changes:

- $9.1 million decrease in net interest expense due to an increase in interest earned on amounts due from customers in the current period.
- $4.7 million decrease in interest on short-term debt primarily due to the average interest rates during the current period being 290 basis points lower than the prior year period even though borrowings were higher in the current period.
- $1.7 million increase in the allowance for borrowed funds.

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. Our capital market strategy has continued to focus on maintaining a strong balance sheet, ensuring sufficient cash resources and daily liquidity, accessing capital markets at favorable times when needed, managing critical business risks, and maintaining a balanced capital structure through the issuance of equity or long-term debt securities or the repurchase of our equity securities.

We believe that the amounts available to us under our existing and planned new credit facility and the issuance of debt and equity securities, together with cash provided by operating activities, will continue to allow us to meet our needs for working capital, construction expenditures, investments in joint ventures, anticipated debt redemptions, dividend payments, pension plan contributions, common stock repurchases and other cash needs.

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. The major factors that affect our working capital are 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 winter heating season (November through March). Cash requirements generally increase during the third and fourth quarters due to increases in natural gas purchases for storage, seasonal construction activity and decreases in receipts from customers.

During the winter 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 changes in the price of natural gas, which is a function of market fluctuations in the commodity cost 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 regulatory deferred accounts and 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. Warmer-than-normal weather can lead to reduced operating cash flows, thereby increasing the need for short-term bank borrowings to meet current cash requirements.

Because of the economic weakness, including continued high unemployment, we may incur additional bad debt expense as a result of the winter heating season, as well as experience increased customer conservation. We may incur more short-term debt to pay for gas supplies and other operating costs since collections from customers could be slower and some customers may not be able to pay their bills. Regulatory margin stabilizing and cost recovery mechanisms, such as those that allow us to recover the gas cost portion of bad debt expense, will significantly mitigate the impact these factors may have on our results of operations.

Net cash provided by operating activities was $360.5 million in 2010, $344.3 million in 2009 and $69.2 million in 2008. Net cash provided by operating activities reflects a $19.1 million increase in net income for 2010 compared with 2009, including the after-tax gain of $30.3 million on the sale of half of our interest in SouthStar as discussed above in "Results of Operations." The effect of changes in working capital on net cash provided by operating activities is described below:

- Trade accounts receivable and unbilled utility revenues decreased $21.3 million in the current period primarily due to a decrease in unbilled volumes and amounts billed to customers reflecting lower gas costs in 2010 as compared with 2009, partially offset by weather in the current period being 3.6% colder than the same prior period. Volumes sold to residential and commercial customers increased 4.5 million dekatherms primarily due to the colder weather. Total throughput, including industrial and power generation volumes, increased 35.7 million dekatherms as compared with the same prior period.
- Net amounts due from customers decreased $133.8 million in the current period primarily due to the collection of deferred gas costs through rates.
- Gas in storage decreased $1.9 million in the current period primarily due to a decrease in the weighted average cost of gas purchased for injection, partially offset by an increased volume of gas in storage at period end.
- Prepaid gas costs decreased $3.6 million in the current period primarily due to the lower average cost of gas in prepaid storage and a decrease in the volumes. Under

some gas supply contracts, prepaid gas costs incurred during summer months represent purchases of gas that are not available for sale, and therefore not recorded in inventory, until the start of the winter heating season.

- Trade accounts payable decreased $4.2 million in the current period primarily due to gas purchases at lower costs during the period.

Our three state regulatory commissions approve rates that are designed to give us the opportunity to generate revenues to cover our gas costs, fixed and variable non-gas costs and earn a fair return for our shareholders. We have a WNA mechanism in South Carolina and Tennessee that partially offsets the impact of colder- 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 credits to customers of $8.8 million in 2010 and $1.2 million in 2009 and charges of $6.8 million in 2008. In Tennessee, adjustments are made directly to individual customer bills. In South Carolina, the adjustments are calculated at the individual customer level but are recorded in "Amounts due from customers" or "Amounts due to customers" in the consolidated balance sheets for subsequent collection from or refund to all customers in the class. The margin decoupling mechanism in North Carolina provides for the collection of our approved margin from residential and commercial customers independent of consumption patterns. The margin decoupling mechanism reduced margin by $5.9 million in 2010 and increased margin by $6 million in 2009 and $25.4 million in 2008. Our gas costs are recoverable through PGA procedures and are not affected by the WNA or the margin decoupling mechanism.

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 regulatory commission approval in North Carolina, South Carolina and Tennessee that places tighter 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, including price, value, availability, environmental attributes, reliability and energy efficiency. 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 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. The price of oil depends upon a number of factors beyond our control, including the relationship between worldwide supply and demand and the policies of foreign and domestic governments and organizations, as well as the value of the US dollar versus other currencies. Our liquidity could be impacted, either positively or negatively, as a result of alternate fuel decisions made by industrial customers.

In an effort to keep customer rates competitive and to maximize earnings, we continue to implement business process improvement and operations and maintenance cost management programs to capture operational efficiencies while improving customer service and maintaining a safe and reliable system.

Cash Flows from Investing Activities. Net cash used in investing activities was $128.6 million in 2010, $129.6 million in 2009 and $177.4 million in 2008. Net cash used in investing activities was primarily for utility construction expenditures. Gross utility construction expenditures were $199.1 million in 2010, a 54% increase from the $129 million in 2009, primarily due to expending $52 million for the construction of power generation projects in 2010 as compared with $3 million funded for these projects in the prior year.

We have a substantial capital expansion program for construction of distribution facilities, purchase of equipment and other general improvements. This program primarily supports our system infrastructure and the growth in our customer base. Significant utility construction expenditures are expected to continue to meet long-term growth, particularly in the power generation market, and are part of our long-range forecasts that are prepared at least annually and typically cover a forecast period of five years. We are not contractually obligated to expend capital until the work is completed.

We anticipate making capital expenditures, including AFUDC, of $146 million, $122 million and $58 million in our fiscal years 2011, 2012 and 2013, respectively, to provide natural gas service in the power generation market. Specific projects are discussed in more detail below. These expenditures are significantly higher than we have traditionally expended. All expenditures related to these projects will be funded with internally generated cash as well as short-term and long-term debt. We do not anticipate the need to issue additional equity to fund these projects.

In millions	2011	2012	2013
Utility capital expenditures	$ 167	$ 178	$ 206
Power generation related capital expenditures	146	122	58
Total forecasted capital expenditures	$ 313	$ 300	$ 264

In October 2009, we reached an agreement with Progress Energy Carolinas, Inc. to provide natural gas delivery service to a power generation facility to be built at their Wayne County, North Carolina site. The agreement, approved by the NCUC in May 2010, calls for us to construct 38 miles of 20-inch transmission pipeline along with compression facilities to provide natural gas delivery service to the plant by June 2012; construction began in February 2010. Our investment in the pipeline and compression facilities is estimated at $89 million and is supported by a long-term service agreement. We have incurred $3.5 million on this project as of October 31, 2010. To provide the additional delivery service, we have executed an agreement with Cardinal Pipeline Company, LLC (Cardinal) to expand our firm capacity requirement by 149,000 dekatherms per day to serve this facility. This will require Cardinal to spend as much as $53.1 million to expand its system. As a 21.49% equity venture partner of Cardinal, we will invest as much as $11.4 million in Cardinal's system expansion. For further information regarding this agreement, see Note 11 to the consolidated financial statements.

In April 2010, we reached another agreement with Progress Energy Carolinas to provide natural gas delivery service to a power generation facility to be built at their existing Sutton site near Wilmington, North Carolina. The agreement, approved by the NCUC in May 2010, calls for us to construct 133 miles of transmission pipeline along with compression facilities to provide natural gas delivery service to the plant by June 2013; we began construction in May 2010. Our investment in the pipeline and compression facilities is estimated at $231 million, and our service to Progress Energy Carolinas is supported by a long-term service agreement. We have incurred $3 million on this project as of October 31, 2010.

The Sutton facilities will also create cost effective expansion capacity that we will use to help serve the growing natural gas requirements of our customers in the eastern part of North Carolina. At the present time with the timing and design scope of the Sutton facilities, there is no current need to proceed with our previously announced Robeson liquefied natural gas (LNG) peak storage project. The timing and design scope of the expansion of our facilities in this area will be determined as our system infrastructure and market supply growth requirements in North Carolina dictate.

During the first quarter of fiscal 2011, we completed construction on a power generation project that will provide natural gas delivery service to a Progress Energy Carolinas' power generation facility located in Richmond County, North Carolina, at a total estimated project cost of $23 million.

During the first quarter of fiscal 2011, we placed a power generation project into service for natural gas delivery service to a Duke Energy Carolinas' power generation facility located in Rowan County, North Carolina, at a total estimated project cost of $29 million. We have a second agreement with Duke Energy Carolinas for their Rockingham County, North Carolina power generation facility for service planned November 2011.

During 2007, $2.2 million of supplier refunds was recorded as restricted cash. Pursuant to a 2007 NCUC order, restrictions on cash totaling $2.2 million were removed in 2008, and we liquidated all certificates of deposit and similar investments that held any supplier refunds due to customers and transferred these funds upon maturity to the North Carolina deferred account.

In 2009 and 2008, we contributed $.9 million and $10.9 million, respectively, to our Hardy Storage Company, LLC (Hardy Storage) joint venture as part of our equity contribution for construction of the FERC regulated interstate storage facility. We made no contribution in 2010 as Hardy Storage converted its construction interim notes in March 2010. For further information on Hardy Storage, see Note 11 to the consolidated financial statements.

On January 1, 2010, we sold half of our 30% membership interest in SouthStar to GNGC and retained a 15% earnings and membership share in SouthStar after the sale. Prior to the sale, earnings and losses were allocated to us at 25% with the exception of earnings and losses in the Ohio and Florida markets, which were allocated to us at our membership percentage of 30%. At closing, we received $57.5 million from GNGC resulting in an after-tax gain of $30.3 million, or $.42 per diluted share. For further information regarding the sale, see Note 11 to the consolidated financial statements.

During 2008, we sold various properties located in Burlington and High Point, North Carolina, Spartanburg, South Carolina and Nashville, Tennessee for $13.2 million, net of expenses. In accordance with utility plant accounting, we recorded the disposition of the land from these sales as a pre-tax gain of $1.2 million with a deferral of $.5 million related to the Nashville sale. The net pre-tax gain of $.7 million was recorded in "Other Income (Expense)" in the consolidated statements of income. We recorded a gain of $3.1 million on the disposition of the buildings as a charge to "Accumulated depreciation" in the consolidated balance sheets. We entered into a sale-leaseback agreement on the Nashville property for a lease of 18 ½ months, where the $.5 million deferred gain was amortized on a straight-line basis over the life of the lease and recorded to "Other Income (Expense)" in the consolidated statements of income. As of October 31, 2010, the $.5 million deferred gain was fully amortized.

Cash Flows from Financing Activities. Net cash provided by (used in) financing activities was ($233.9) million in 2010, ($214.1) million in 2009 and $107.7 million in 2008. Funds are primarily provided from bank borrowings and the issuance of common stock through DRIP and employee stock purchase plans, net of purchases under the common stock repurchase program. We may sell common stock and long-term debt when market and other conditions favor such long-term financing. Funds are primarily used to pay down outstanding short-term bank borrowings, to repurchase common stock under the common stock repurchase program and to pay quarterly dividends on our common stock. As of October 31, 2010, our current assets were $327.8 million and our current liabilities were $498.6 million, primarily due to seasonal requirements as discussed above.

As of October 31, 2010, we had committed lines of credit of $450 million with the ability to expand up to $600 million under our syndicated credit facility that expires April 2011 to meet working capital needs, capital expenditures and approved acquisitions. We pay an annual fee of $35,000 plus six basis points for any unused amount up to $450 million. Outstanding short-term bank borrowings decreased from $306 million as of October 31, 2009 to $242 million as of October 31, 2010 primarily due to lower commodity gas costs and recovery of amounts due from customers. During the twelve months ended October 31, 2010, short-term bank borrowings ranged from zero to $342.5 million, and interest rates ranged from .48% to .61% when borrowing (weighted average of .50%).

Effective December 3, 2008, we entered into a syndicated seasonal credit facility with aggregate commitments totaling $150 million. Advances under this seasonal facility bore interest at a rate based on the 30-day LIBOR rate plus from 75 to 175 basis points, based on our credit ratings. This seasonal credit facility expired on March 31, 2009. We entered into this facility to provide lines of credit in addition to the syndicated credit facility discussed above in order to have additional resources to meet seasonal cash flow requirements and general corporate needs. This seasonal credit facility replaced the two short-term credit facilities with banks for unsecured commitments totaling $75 million that were effective from October 27 and 29, 2008 through December 3, 2008.

As of October 31, 2010, we had available letters of credit of $5 million under our syndicated five-year revolving credit facility, of which $2.7 million were issued and outstanding. The letters of credit are used to guarantee claims from self-insurance under our general and automobile liability policies. As of October 31, 2010, unused lines of credit available under our syndicated five-year revolving credit facility, including the issuance of the letters of credit, totaled $205.3 million.

On November 18, 2010, we entered into a joint commitment letter dated November 17, 2010 to replace our existing credit facility with a syndicated $650 million three-year revolving credit facility, scheduled to be executed and effective by January 31, 2011. The new credit facility is expected to have an option for an additional commitment of $200 million, for a total aggregate commitment of $850 million. The new credit facility is expected to have financial covenants similar to our current existing syndicated credit facility and provisions regarding defaulting lenders and replacements of lenders. Because of the current market conditions, we anticipate that the costs of our new credit facility will be higher than those costs incurred under our current credit facility.

The level of short-term bank borrowings can vary significantly due to changes in the wholesale prices of natural gas, the level of purchases of natural gas supplies for storage and hedging transactions to serve customer demand. We pay our suppliers for natural gas purchases before we collect our costs from customers through their monthly bills. If wholesale gas prices increase, we may incur more short-term debt for natural gas inventory 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.

With the appropriate notice, we have the right to redeem our 6.25% insured quarterly notes on June 1, 2011 and thereafter without incurring a premium or penalty. These notes have a balance of $196.9 million as of October 31, 2010. We intend to exercise our redemption right effective June 1, 2011 and finance the redemption by issuing $200 million of long-term debt at a lower interest rate. We do not anticipate issuing any other long-term debt in fiscal 2011. We intend to issue $225 million of long-term debt in the first quarter of our fiscal year 2012 for general corporate purposes. We continually monitor customer growth trends in our markets along with the economic recovery of our service area for the timing of any infrastructure investments that would require the need for additional long-term debt.

We retired the balance of $60 million of our 7.8% medium-term notes and $30 million of our 7.35% medium-term notes in September 2010 and September 2009, respectively, as they became due. The balance of $60 million of our 6.55% medium-term notes becomes due in September 2011.

From time to time, we have repurchased shares of common stock under our Common Stock Open Market Purchase Program and our ASR program as described in Note 5 to the consolidated financial statements. During 2010, we repurchased 1.8 million shares for $47.3 million, leaving a balance of 4,510,074 shares in the Common Stock Open Market Purchase Program. During 2009 and 2008, we repurchased .7 million and 1.6 million shares for $17.9 million and $42.7 million, respectively. We anticipate repurchasing .8 million shares of common stock through an ASR agreement in the first quarter of our fiscal year 2011.

During 2010, we issued $19.1 million of common stock through DRIP and employee stock purchase plans. During 2009, we issued $14.4 million of common stock through the DRIP and employee stock purchase plan. As a result of an administrative error, we received $347,000 from November 1, 2009 through November 16, 2009 from the sale of shares of common stock under our DRIP that was from unregistered shares. On February 8, 2010, we filed a registration statement

(Rescission Offer) which offered to rescind the purchase of these unregistered shares and registered all previously unregistered shares issued under the DRIP during that period. Under the Rescission Offer, 711 shares were rescinded for an aggregate consideration of $18,900. For further information, see Note 5 to the consolidated financial statements.

We have paid quarterly dividends on our common stock since 1956. We increased our common stock dividend on an annualized basis by $.04 per share in 2010, 2009 and 2008. Dividends of $80.3 million, $78.4 million and $75.5 million for 2010, 2009 and 2008, respectively, were paid on common stock. Provisions contained in certain note agreements under which long-term debt was issued restrict the amount of cash dividends that may be paid. As of October 31, 2010, our retained earnings were not restricted. On December 16, 2010, the Board of Directors declared a quarterly dividend on common stock of $.28 per share, payable January18, 2011 to shareholders of record at the close of business on December 27, 2010. For further information, see Note 3 to the consolidated financial statements.

Our long-term targeted capitalization ratio is 45-50% in long-term debt and 50-55% in common equity. Accomplishing this capital structure objective and maintaining sufficient cash flow are necessary to maintain attractive credit ratings. As of October 31, 2010, our capitalization, including current maturities of long-term debt, consisted of 43% in long-term debt and 57% in common equity.

The components of our total debt outstanding (short-term and long-term) to our total capitalization as of October 31, 2010 and 2009 are summarized in the table below.

	October 31		October 31	
In thousands	2010	Percentage	2009	Percentage
Short-term debt	$ 242,000	12%	$ 306,000	15%
Current portion of long-term debt	60,000	3%	60,000	3%
Long-term debt	671,922	35%	732,512	36%
Total debt	973,922	50%	1,098,512	54%
Common stockholders' equity	964,941	50%	927,948	46%
Total capitalization (including short-term debt)	$ 1,938,863	100%	$ 2,026,460	100%

Credit ratings impact our ability to obtain short-term and long-term financing and the cost of such financings. We believe our credit ratings will allow us to continue to have access to the capital markets, as and when needed, at a reasonable cost of funds. 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.

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.

As of October 31, 2010, 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 Service (Moody's). Currently, with respect to our long-term debt, the credit agencies maintain their stable outlook. A significant decline in our operating performance or a significant reduction in our liquidity could trigger a negative change in our ratings outlook or even a reduction in our credit ratings by our rating agencies. This would mean more limited access to the private and public credit markets and an increase in the costs of such borrowings. 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.

We are subject to default provisions related to our long-term debt and short-term borrowings. Failure to satisfy any of the default provisions may result in total outstanding issues of debt becoming due. There are cross-default provisions in all of our debt agreements. As of October 31, 2010, there has been no event of default giving rise to acceleration of our debt.

The default provisions of some or all of our senior debt include:

- Failure to make principal or interest payments,
- Bankruptcy, liquidation or insolvency,
- Final judgment against us in excess of $1 million that after 60 days is not discharged, satisfied or stayed pending appeal,
- Specified events under the Employee Retirement Income Security Act of 1974,
- Change in control, and
- Failure to observe or perform covenants, including:
    - interest coverage of 1.75 times, which was 5.91 times as of October 31, 2010,
    - funded debt cannot exceed 70% of total capitalization, which was 43% as of October 31, 2010,
    - funded debt of all subsidiaries in the aggregate cannot exceed 15% of total capitalization, of which there is no funded debt of our subsidiaries as of October 31, 2010,
    - restrictions on permitted liens,
    - restrictions on paying dividends on or repurchasing our stock or making investments in subsidiaries, and
    - restrictions on burdensome agreements.

Contractual Obligations and Commitments

We have incurred various contractual obligations and commitments in the normal course of business. As of October 31, 2010, our estimated recorded and unrecorded contractual obligations are as follows.

	Payments Due by Period				
In thousands	Less than 1 year	1-3 Years	4-5 Years	After 5 Years	Total
Recorded contractual obligations:					
Long-term debt (1)	$ 60,000	$ 100,000	$ -	$ 571,922	$ 731,922
Short-term debt (2)	242,000	-	-	-	242,000
Total	$ 302,000	$ 100,000	$ -	$ 571,922	$ 973,922

(1) See Note 3 to the consolidated financial statements.
(2) See Note 4 to the consolidated financial statements.

In thousands	Less than 1 year	1-3 Years	4-5 Years	After 5 Years	Total
Unrecorded contractual obligations and commitments: (1)					
Pipeline and storage capacity (2)	$ 150,914	$ 315,831	$ 120,252	$ 296,836	$ 883,833
Gas supply (3)	11,862	60	-	-	11,922
Interest on long-term debt (4)	50,163	131,272	79,286	532,656	793,377
Telecommunications and information technology (5)	15,316	5,448	-	-	20,764
Qualified and nonqualified pension plan funding (6)	22,862	36,394	11,453	-	70,709
Postretirement benefits plan funding (6)	1,400	4,000	1,300	-	6,700
Operating leases (7)	4,584	12,834	4,546	1,411	23,375
Other purchase obligations (8)	5,147	-	-	-	5,147
Letters of credit (9)	2,714	10,474	6,982	-	20,170
Total	$ 264,962	$ 516,313	$ 223,819	$ 830,903	$ 1,835,997

(1) In accordance with GAAP, these items are not reflected in our consolidated balance sheets.
(2) Recoverable through PGA procedures.
(3) Reservation fees are recoverable through PGA procedures.
(4) See Note 3 to the consolidated financial statements.
(5) 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.
(6) Estimated funding beyond five years is not available. See Note 8 to the consolidated financial statements.
(7) See Note 7 to the consolidated financial statements.
(8) Consists primarily of pipeline products, vehicles, contractors and merchandise.
(9) See Note 4 to the consolidated financial statements.

Off-balance Sheet Arrangements

We have no off-balance sheet arrangements other than operating leases, letters of credit and the credit extended by our counterparty in over-the-counter (OTC) derivative contracts. The letters of credit and operating leases are discussed in Note 4 and Note 7, respectively, to the consolidated financial statements and are reflected in the table above. The credit extended by our counterparty in OTC derivative contracts in 2009 is discussed in Note 6 to the consolidated financial statements.

As of October 31, 2009, Piedmont Energy Partners, Inc., a wholly owned subsidiary of Piedmont, had entered into a guaranty in the normal course of business pertaining to our investment in Hardy Storage. The guaranty involved some levels of performance and credit risk that were not included in our consolidated balance sheets. We had recorded an estimated liability of $1.2 million as of October 31, 2009. The possibility of having to perform on the guaranty was largely dependent upon the future operations of Hardy Storage, third parties or the occurrence of certain future events. In March 2010, Hardy Storage obtained long-term non-recourse project financing, and we were released from any liability under the guaranty, and accordingly, we reversed the liability for the guaranty. For further information on this guaranty, see Note 11 to the consolidated financial statements.

Critical Accounting 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 is responsible for the selection of these critical accounting estimates. Management has discussed these critical accounting estimates presented below with the Audit Committee of the Board of Directors.

<u>Regulatory Accounting</u>. Our regulated utility segment is subject to regulation by certain state and federal authorities. Our accounting policies conform to the accounting regulations required by rate regulated operations 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, 2010 and 2009 totaled $197.8 million and $337.5 million, respectively. Regulatory liabilities as of October 31, 2010 and 2009 totaled $439.1 million and $409.3 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. In South Carolina and Tennessee, we have 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 margin decoupling mechanism provides for the recovery of our approved margin from residential and commercial customers independent of consumption patterns. The margin earned monthly under the margin decoupling mechanism results in semi-annual rate adjustments to refund any over-collection or recover any under-collection. The gas cost portion of our costs is recoverable through PGA procedures and is not affected by the WNA or the margin decoupling mechanism. Without the WNA or margin decoupling mechanism, our operating revenues would have been higher by $14.7 million in 2010 and lower by $4.8 million and $32.2 million in 2009 and 2008, 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 margin decoupling mechanism, as applicable. Secondary market revenues are recognized when the physical sales are delivered based on contract or market prices.

Pension and Postretirement Benefits. For eligible employees hired on or before December 31, 2007 (December 31, 2008 for employees covered under the bargaining unit contract in Nashville, Tennessee), we have a traditional defined benefit pension plan, which was amended to close the plan to employees hired after December 31, 2007 (December 31, 2008 for employees covered under the bargaining unit contract in Nashville, Tennessee) and to modify how benefits are accrued. We also provide certain postretirement health care and life insurance benefits to eligible employees. For further information and our reported costs of providing these benefits, see Note 8 to the consolidated financial statements. The costs of providing these benefits 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.

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 plan changed from 5.99% in 2009 to 5.47% in 2010. For the nonqualified pension plans, the weighted average discount rate used in the measurement of the benefit obligation changed from 5.28% in 2009 to 4.37% in 2010. Similarly, based on this approach, the weighted average discount rate for postretirement benefits changed from 5.58% in 2009 to 4.85% in 2010. Based on our review of actual cost trend rates and projected future trends in establishing health care cost trend rates, the initial health care cost trend rate as established in 2009 was assumed to be 8% in 2010, declining gradually to 5% in 2027.

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 50% equity securities and 50% fixed income securities. The expected long-term rate of return on plan assets was 8% in 2008, 2009 and 2010. Based on a fairly stagnant inflation trend, our age-related assumed rate of increase in future compensation levels was 3.97% in 2008, decreasing to 3.92% in 2009 and further decreasing to 3.87% in 2010 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 2010 Benefit Cost	Impact on Projected Benefit Obligation
		Increase (Decrease) In thousands	
Discount rate	(.25)%	$ 459	$ 5,255
Rate of return on plan assets	(.25)%	586	N/A
Rate of increase in compensation	.25 %	539	3,160

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	Change in Assumption	Impact on 2010 Postretirement Benefit Cost	Impact on Accumulated Postretirement Benefit Obligation
		Increase (Decrease) In thousands	
Discount rate	(.25)%	$ 9	$ 767
Rate of return on plan assets	(.25)%	46	N/A
Health care cost trend rate	.25 %	14	182

We utilize accounting methods consistently applied that are allowed under GAAP which 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.

Gas Supply and Regulatory Proceedings

In recent years, we have sought to diversify 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. We have firm, long-term transportation contract service that provides access to Canadian and Rocky Mountain gas supplies via the Chicago hub, primarily to serve our Tennessee markets. We have firm, long-term market-area storage service in West Virginia from Hardy Storage, a venture in which we have a 50% equity interest in the project which is more fully discussed in Note 11 to the consolidated financial statements.

We are currently expanding our transmission system and compression facilities to provide natural gas delivery service to Progress Energy Carolinas for two power generation facilities that are under construction at their Wayne County, North Carolina site and at their existing Sutton site near Wilmington, North Carolina. Our investment to service these new contracts will occur over the next two and one-half years. For further information on these investments, see "Cash Flows from Investing Activities" in Management's Discussion and Analysis of this Form 10-K. Also, in relation to the Wayne County agreement, we have executed an agreement with Cardinal to expand our firm capacity requirement by 149,000 dekatherms per day to serve this facility. As a 21.49% equity venture partner of Cardinal, we will invest as much as $11.4 million in Cardinal's system expansion. For further information on our equity venture, see Note 11 to the consolidated financial statements.

The Sutton facilities will also create expansion capacity that we will use to help serve the growing natural gas requirements of our customers in the eastern part of North Carolina. While not satisfying any future market supply requirements, since the Sutton facilities will help serve our near term system pressure requirements in a cost effective manner, we have delayed work on the Robeson LNG peak storage facility. The timing and design scope of expansion of our facilities in this area will be determined as our system infrastructure and market supply growth requirements in North Carolina dictate.

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 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 TIP discussed in Note 2 to the consolidated financial statements.

In October 2008, the NCUC approved a settlement in our general rate case proceeding that provided an annual revenue increase of $15.7 million and the continuation of the margin decoupling mechanism. The new rates became effective November 1, 2008. Also in October 2008, the PSCSC issued an order approving a settlement that provided for an annual decrease of $1.5 million in margin under the rate stabilization adjustment mechanism based on a return on equity of 11.2%, effective November 1, 2008. In October 2009, the PSCSC issued an order approving a settlement that provides for an annual increase in margin of $1.1 million based on a return on equity of 11.2%, effective November 1, 2009. In October 2010, the PSCSC issued an order approving a settlement that provides an annual increase in margin of $.75 million based on a return on equity of 11.3%, effective November 1, 2010.

In October 2009, we filed a petition with the PSCSC requesting approval to offer three energy efficiency programs to residential and commercial customers at a total cost of $.35 million that were designed to promote energy conservation and efficiency. These programs were similar to approved energy efficiency programs in North Carolina. On May 20, 2010, the PSCSC approved the energy efficiency programs on a three-year experimental basis with equipment rebates on the purchase of high-efficiency natural gas equipment and weatherization assistance for low-income residential customers. For further information on these programs, see the discussion in Note 2 to the consolidated financial statements.

In February 2010, we filed a petition with the TRA to adjust the applicable rate for the collection of the Nashville franchise fee from certain customers. The proposed rate adjustment was calculated to recover the net $2.9 million of under-collected Nashville franchise fee payments as of May 31, 2009. In April 2010, the TRA passed a motion approving a new Nashville franchise fee rate designed to recover only the net under-collections that have accrued since June 1, 2005, which would deny recovery of $1.5 million for us. Once the TRA issues its order on this matter, we intend to seek their reconsideration. We are unable to predict the outcome of this proceeding at this time. However, we do not believe this matter will have a material effect on our financial position, results of operations or cash flows.

We continue to work with our regulatory commissions to earn a fair rate of return for our shareholders and provide safe, reliable natural gas distribution service to our customers. For further information about regulatory proceedings and other regulatory information, see Note 2 to the consolidated financial statements.

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 Guidance

For information regarding recently issued accounting guidance, see Note 1.Q. to the consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to various forms of market risk, including the credit risk of our suppliers and our customers, interest rate risk, commodity price risk and weather risk. We seek to identify, assess, monitor and manage market risk and credit risk in accordance with defined policies and procedures under an Enterprise Risk Management Policy and with the direction of the Energy Price Risk Management Committee. Risk management is guided by senior management with Board of Directors' oversight, and senior management takes an active role in the development of policies and procedures.

We hold all financial instruments discussed below for purposes other than trading.

Credit Risk

We enter into contracts with third parties to buy and sell natural gas. Our policy requires counterparties to have an investment-grade credit rating at the time of the contract. In situations where our counterparties do not have investment grade credit ratings, our policy requires credit enhancements that include letters of credit or parental guaranties. In either circumstance, the policy specifies limits on the contract amount and duration based on the counterparty's credit rating and/or credit support. In order to minimize our exposure, we continually re-evaluate third-party creditworthiness and market conditions and modify our requirements accordingly.

We also enter into contracts with third parties to manage some of our supply and capacity assets for the purpose of maximizing their value. These arrangements include a counterparty credit evaluation according to our policy described above prior to contract execution and typically have durations of one year or less. In the event that a party is unable to perform under these arrangements, we have exposure to satisfy our underlying supply or demand contractual obligations that were incurred while under the management of this third party.

We have mitigated exposure to the risk of nonpayment of utility bills by customers. In North Carolina and South Carolina, gas costs related to uncollectible accounts are recovered through PGA procedures. In Tennessee, the gas cost portion of net write-offs for a fiscal year that exceed the gas cost portion included in base rates is recovered through PGA procedures. To manage the non-gas cost customer credit risk, we evaluate credit quality and payment history and may require cash deposits from those customers that do not satisfy our predetermined credit standards. Significant increases in the price of natural gas can also slow our collection efforts as customers experience increased difficulty in paying their gas bills, leading to higher than normal accounts receivable.

Interest Rate Risk

We are exposed to interest rate risk as a result of changes in interest rates on short-term debt. As of October 31, 2010, all of our long-term debt was issued at fixed rates, and therefore not subject to interest rate risk.

We have short-term borrowing arrangements to provide working capital and general corporate liquidity. The level of borrowings under such arrangements varies from period to period depending upon many factors, including the cost of wholesale natural gas and our gas supply hedging programs, our investments in capital projects, the level and expense of our storage inventory and the collection of receivables. Future short-term interest expense and payments will be impacted by both short-term interest rates and borrowing levels.

As of October 31, 2010, we had $242 million of short-term debt outstanding under our syndicated revolving credit facility at an interest rate of .51%. The carrying amount of our short-term debt approximates fair value. A 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 $1.6 million during 2010.

As of October 31, 2010, information about our long-term debt is presented below.

	Expected Maturity Date							Fair Value as of October 31,
In millions	2011	2012	2013	2014	2015	Thereafter	Total	2010
Fixed Rate Long-term Debt	$ 60	$ -	$ -	$ 100	$ -	$ 571.9	$ 731.9	$ 890.3
Average Interest Rate	6.55 %	- %	- %	5.00 %	- %	6.93 %	6.64 %	

Commodity Price Risk

We have mitigated the cash flow risk resulting from commodity purchase contracts under our regulatory gas cost recovery mechanisms that permit the recovery of these costs in a timely manner. As such, we face regulatory recovery risk associated with these costs. With regulatory commission approval, we revise rates periodically without formal rate proceedings to reflect changes in the wholesale cost of gas, including costs associated with our hedging programs under the recovery mechanism allowed by each of our state regulators. Under our PGA procedures, differences between gas costs incurred and gas costs billed to customers are deferred, and any under-recoveries are included in "Amounts due from customers" or any over-recoveries are included in "Amounts due to customers" in our consolidated balance sheets for collection or refund over subsequent periods. When we have "Amounts due from customers," we earn a carrying charge that mitigates any incremental short-term borrowing costs. When we have "Amounts due to customers," we incur a carrying charge that we must refund to our customers.

We manage our gas supply costs through a portfolio of short- and long-term procurement and storage contracts with various suppliers. We actively manage our supply portfolio to balance sales and delivery obligations. We inject natural gas into storage during the summer months and withdraw the gas during the winter heating season. In the normal course of business, we utilize New York Mercantile Exchange (NYMEX) exchange traded instruments and have used OTC instruments of various durations for the forward purchase of a portion of our natural gas requirements, subject to regulatory review and approval.

Our gas purchasing practices and costs are subject to regulatory reviews in all three states in which we operate. Costs have never been disallowed on the basis of prudence in any jurisdiction.

Weather Risk

We are exposed to weather risk in our regulated utility segment in South Carolina and Tennessee where revenues are collected from volumetric rates without a margin decoupling mechanism. Our rates are designed based on an assumption of normal weather. In these states, this risk is mitigated by WNA mechanisms that are designed to offset the impact of colder-than-normal or warmer-than-normal weather in our residential and commercial markets. In North Carolina, we manage our weather risk through a margin decoupling mechanism that allows us to recover our approved margin from residential and commercial customers independent of volumes sold.

Additional information concerning market risk is set forth in "Financial Condition and Liquidity" in Item 7 of this Form 10-K in Management's Discussion and Analysis of Financial Condition and Results of Operations.

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.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Piedmont Natural Gas Company, Inc. and subsidiaries (the "Company") as of October 31, 2010 and 2009, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended October 31, 2010. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these 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, such consolidated financial statements present fairly, in all material respects, the financial position of Piedmont Natural Gas Company, Inc. and subsidiaries at October 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended October 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

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, 2010, 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 23, 2010 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Charlotte, North Carolina
December 23, 2010

Consolidated Balance Sheets
October 31, 2010 and 2009

ASSETS

In thousands	2010	2009
Utility Plant:		
Utility plant in service	$ 3,176,312	$ 3,071,742
Less accumulated depreciation	917,300	862,079
Utility plant in service, net	2,259,012	2,209,663
Construction work in progress	171,901	87,978
Plant held for future use	6,751	6,751
Total utility plant, net	2,437,664	2,304,392
Other Physical Property, at cost (net of accumulated depreciation of $729 in 2010 and $2,497 in 2009)	528	719
Current Assets:		
Cash and cash equivalents	5,619	7,558
Trade accounts receivable (less allowance for doubtful accounts of $929 in 2010 and $990 in 2009)	62,370	70,979
Income taxes receivable	24,856	44,413
Other receivables	2,289	4,712
Unbilled utility revenues	21,337	33,925
Inventories:		
Gas in storage	101,734	103,584
Materials, supplies and merchandise	4,547	5,262
Gas purchase derivative assets, at fair value	2,819	2,559
Amounts due from customers	62,336	196,130
Prepayments	39,832	43,930
Other current assets	101	96
Total current assets	327,840	513,148
Noncurrent Assets:		
Equity method investments in non-utility activities	80,287	104,430
Goodwill	48,852	48,852
Marketable securities, at fair value	997	441
Overfunded postretirement asset	17,342	-
Regulatory asset for postretirement benefits	64,775	76,905
Unamortized debt expense	8,576	9,177
Regulatory cost of removal asset	17,825	16,293
Other noncurrent assets	48,589	44,462
Total noncurrent assets	287,243	300,560
Total	$ 3,053,275	$ 3,118,819

See notes to consolidated financial statements.

Consolidated Balance Sheets
October 31, 2010 and 2009

CAPITALIZATION AND LIABILITIES

In thousands	2010	2009
Capitalization:		
Stockholders' equity:		
Cumulative preferred stock - no par value - 175 shares authorized	$ -	$ -
Common stock - no par value - shares authorized: 200,000; shares outstanding: 72,282 in 2010 and 73,266 in 2009	445,640	471,569
Retained earnings	519,831	458,826
Accumulated other comprehensive loss	(530)	(2,447)
Total stockholders' equity	964,941	927,948
Long-term debt	671,922	732,512
Total capitalization	1,636,863	1,660,460
Current Liabilities:		
Current maturities of long-term debt	60,000	60,000
Bank debt	242,000	306,000
Trade accounts payable	66,019	67,010
Other accounts payable	49,645	48,431
Accrued interest	20,134	21,294
Customers' deposits	25,631	25,202
Deferred income taxes	4,933	14,138
General taxes accrued	20,100	19,993
Gas purchase derivative liabilities, at fair value	-	30,603
Other current liabilities	10,098	7,540
Total current liabilities	498,560	600,211
Noncurrent Liabilities:		
Deferred income taxes	429,225	377,562
Unamortized federal investment tax credits	2,145	2,422
Accumulated provision for postretirement benefits	14,805	31,641
Cost of removal obligations	436,072	408,955
Other noncurrent liabilities	35,605	37,568
Total noncurrent liabilities	917,852	858,148
Commitments and Contingencies (Note 7)		
Total	$ 3,053,275	$ 3,118,819

See notes to consolidated financial statements.

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Consolidated Statements of Income
For the Years Ended October 31, 2010, 2009 and 2008

In thousands except per share amounts	2010	2009	2008
Operating Revenues	$ 1,552,295	$ 1,638,116	$ 2,089,108
Cost of Gas	999,703	1,076,542	1,536,135
Margin	552,592	561,574	552,973
Operating Expenses:			
Operations and maintenance	219,829	208,105	210,757
Depreciation	98,494	97,425	93,121
General taxes	33,909	34,590	33,170
Income taxes	62,082	70,079	62,814
Total operating expenses	414,314	410,199	399,862
Operating Income	138,278	151,375	153,111
Other Income (Expense):			
Income from equity method investments	28,854	33,464	27,718
Gain on sale of interest in equity method investment	49,674	-	-
Non-operating income	659	32	1,320
Charitable contributions	(1,363)	(2,011)	(1,327)
Non-operating expense	(643)	(1,558)	(864)
Income taxes	(29,794)	(11,803)	(10,678)
Total other income (expense)	47,387	18,124	16,169
Utility Interest Charges:			
Interest on long-term debt	52,666	55,105	55,449
Allowance for borrowed funds used during construction	(9,981)	(2,298)	(4,002)
Other	1,026	(6,132)	7,826
Total utility interest charges	43,711	46,675	59,273
Net Income	$ 141,954	$ 122,824	$ 110,007
Average Shares of Common Stock:			
Basic	72,275	73,171	73,334
Diluted	72,525	73,461	73,612
Earnings Per Share of Common Stock:			
Basic	$ 1.96	$ 1.68	$ 1.50
Diluted	$ 1.96	$ 1.67	$ 1.49

See notes to consolidated financial statements.

Consolidated Statements of Cash Flows
For the Years Ended October 31, 2010, 2009 and 2008

In thousands	2010	2009	2008
Cash Flows from Operating Activities:			
Net income	$ 141,954	$ 122,824	$ 110,007
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	102,776	102,592	97,637
Amortization of investment tax credits	(277)	(204)	(358)
Allowance for doubtful accounts	(61)	(76)	522
Gain on sale of interest in equity method investment, net of tax	(30,286)	-	-
Net gain on sale of property	(89)	(495)	(711)
Income from equity method investments	(28,854)	(33,464)	(27,718)
Distributions of earnings from equity method investments	28,834	23,954	34,060
Deferred income taxes	21,831	81,468	28,370
Stock-based compensation expense	-	-	338
Changes in assets and liabilities:			
Gas purchase derivatives, at fair value	(30,863)	18,741	23,029
Receivables	23,493	25,018	(12,685)
Inventories	2,565	87,953	(60,139)
Amounts due from customers	133,794	(14,385)	(105,710)
Settlement of legal asset retirement obligations	(1,141)	(1,480)	(1,358)
Overfunded postretirement asset	(17,342)	6,797	29,459
Regulatory asset for postretirement benefits	12,130	(48,173)	(26,867)
Other assets	18,184	(13,573)	(8,936)
Accounts payable	(3,007)	(22,154)	(8,617)
Amounts due to customers	-	-	(162)
Regulatory liability for postretirement benefits	-	(372)	(13,504)
Provision for postretirement benefits	(16,836)	15,384	(1,212)
Other liabilities	3,706	(6,085)	13,757
Net cash provided by operating activities	360,511	344,270	69,202
Cash Flows from Investing Activities:			
Utility construction expenditures	(199,059)	(129,006)	(181,001)
Allowance for funds used during construction	(9,981)	(2,298)	(4,002)
Contributions to equity method investments	-	(862)	(10,917)
Distributions of capital from equity method investments	18,260	32	98
Proceeds from sale of interest in equity method investment	57,500	-	-
Proceeds from sale of property	1,653	748	13,159
Decrease in restricted cash	-	-	2,196
Investments in marketable securities	(498)	(380)	-
Other	3,554	2,154	3,090
Net cash used in investing activities	(128,571)	(129,612)	(177,377)

Consolidated Statements of Cash Flows
For the Years Ended October 31, 2010, 2009 and 2008

In thousands	2010	2009	2008
Cash Flows from Financing Activities:			
Borrowings under bank debt	1,058,000	1,075,000	1,687,000
Repayments under bank debt	(1,122,000)	(1,175,500)	(1,476,000)
Retirement of long-term debt	(60,590)	(31,749)	(626)
Expenses related to the issuance of long-term debt	-	-	(10)
Expenses related to expansion of the credit facility	(46)	-	(113)
Issuance of common stock through dividend reinvestment and employee stock plans	19,099	14,435	15,591
Repurchases of common stock	(47,295)	(17,857)	(42,678)
Dividends paid	(80,255)	(78,370)	(75,513)
Other	(792)	(50)	-
Net cash provided by (used in) financing activities	(233,879)	(214,091)	107,651
Net Increase (Decrease) in Cash and Cash Equivalents	(1,939)	567	(524)
Cash and Cash Equivalents at Beginning of Year	7,558	6,991	7,515
Cash and Cash Equivalents at End of Year	$ 5,619	$ 7,558	$ 6,991
Cash Paid During the Year for:			
Interest	$ 56,554	$ 61,050	$ 63,769
Income taxes	30,460	50,787	29,281
Noncash Investing and Financing Activities:			
Accrued construction expenditures	$ 3,225	$ 1,305	$ 1,340
Guaranty	1,234	-	101

See notes to consolidated financial statements.

Consolidated Statements of Stockholders' Equity
For the Years Ended October 31, 2010, 2009 and 2008

In thousands except per share amounts	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance, October 31, 2007	$ 497,570	$ 402	$ 379,682	$ 720	$ 878,374
Comprehensive Income:					
Net income			110,007		110,007
Other comprehensive income:					
Unrealized gain from hedging activities of equity method investments, net of tax of $891				1,399	1,399
Reclassification adjustment of realized gain from hedging activities of equity method investments included in net income, net of tax of ($922)				(1,449)	(1,449)
Total comprehensive income					109,957
Common Stock Issued	16,673				16,673
Common Stock Repurchased	(42,678)				(42,678)
Share-Based Compensation Expense		338			338
Dividends - Incentive Compensation Plan		23	(23)		-
Tax Benefit from Dividends Paid on ESOP Shares			93		93
Dividends Declared ($1.03 per share)			(75,513)		(75,513)
Balance, October 31, 2008	471,565	763	414,246	670	887,244
Comprehensive Income:					
Net income			122,824		122,824
Other comprehensive income:					
Unrealized gain from hedging activities of equity method investments, net of tax of ($3,886)				(6,032)	(6,032)
Reclassification adjustment of realized gain from hedging activities of equity method investments included in net income, net of tax of $1,879				2,915	2,915
Total comprehensive income					119,707
Common Stock Issued	17,861				17,861
Common Stock Repurchased	(17,857)				(17,857)
Share-Based Compensation Expense		(730)			(730)
Dividends - Incentive Compensation Plan		(33)	33		-
Tax Benefit from Dividends Paid on ESOP Shares			93		93
Dividends Declared ($1.07 per share)			(78,370)		(78,370)
Balance, October 31, 2009	471,569	-	458,826	(2,447)	927,948

Consolidated Statements of Stockholders' Equity
For the Years Ended October 31, 2010, 2009 and 2008

In thousands except per share amounts	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Comprehensive Income:					
Net income			141,954		141,954
Other comprehensive income:					
Unrealized gain from hedging activities of equity method investments, net of tax of ($52)				(88)	(88)
Reclassification adjustment of realized gain from hedging activities of equity method investments included in net income, net of tax of $1,291				2,005	2,005
Total comprehensive income					143,871
Common Stock Issued	21,366				21,366
Common Stock Repurchased	(47,276)				(47,276)
Rescission Offer	(19)				(19)
Costs of Rescission Offer			(792)		(792)
Tax Benefit from Dividends Paid on ESOP Shares			98		98
Dividends Declared ($1.11 per share)			(80,255)		(80,255)
Balance, October 31, 2010	$ 445,640	$ -	$ 519,831	$ (530)	$ 964,941

The components of accumulated other comprehensive income (loss) (OCI) as of October 31, 2010 and 2009 are as follows.

In thousands	2010	2009
Hedging activities of equity method investments, net of tax	$ (530)	$ (2,447)

See notes to consolidated financial statements.

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, industrial and power generation 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 2 to the consolidated financial statements.

The consolidated financial statements reflect the accounts of Piedmont and its wholly owned subsidiaries. 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 accounting regulations prescribed under rate-based regulation.

We monitor significant events occurring after the balance sheet date and prior to the issuance of the financial statements to determine the impacts, if any, of events on the financial statements to be issued. All subsequent events of which we are aware were evaluated through the filing date of this Form 10-K. There are no subsequent events that had a material impact on our financial position, results of operations or cash flows. For further information, see Note 13 to the consolidated financial statements.

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. The accounting regulations provide 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 these regulations, 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 accounting for the effects of regulation were no longer applicable, we would recognize a write-off of the regulatory assets and regulatory liabilities that would result in an adjustment to net income. 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 rate-based regulation remains appropriate. It is our opinion that all of our recorded regulatory assets are recoverable in current rates or future rate proceedings.

Regulatory assets and liabilities in the consolidated balance sheets as of October 31, 2010 and 2009 are presented below.

In thousands	2010	2009
Regulatory Assets:		
Unamortized debt expense	$ 8,576	$ 9,177
Amounts due from customers	62,336	196,130
Environmental costs *	7,960	6,205
Demand-side management costs *	-	474
Deferred operations and maintenance expenses *	8,258	8,816
Deferred pipeline integrity expenses *	6,728	6,467
Deferred pension and other retirement benefits costs *	18,783	15,535
Amounts not yet recognized as a component of pension and other retirement benefits costs	64,775	76,905
Regulatory cost of removal asset	17,825	16,293
Other *	2,531	1,541
Total	$ 197,772	$ 337,543
Regulatory Liabilities:		
Regulatory cost of removal obligations	$ 412,776	$ 385,624
Deferred income taxes *	26,299	23,699
Total	$ 439,075	$ 409,323

* Regulatory assets are included in "Other" in "Noncurrent Assets" and regulatory liabilities are included in "Other" in "Noncurrent Liabilities" in the consolidated balance sheets.

As of October 31, 2010, we had regulatory assets totaling $2.4 million on which we do not earn a return during the applicable recovery periods. The original amortization periods for these assets range from 3 to 15 years and, accordingly, $1.8 million will be fully amortized by 2011 and $.6 million will be fully amortized by 2018. We have $6.2 million related to unrealized mark-to-market amounts on which we do not earn a return until they are recorded in interest-bearing amounts due to/from customer accounts when realized and $64.8 million of regulatory postretirement assets, $17.8 million of asset retirement obligations (AROs) and $8 million of estimated environmental costs on which we do not earn a return.

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). Major expenditures that last longer than a year and improve or lengthen the expected useful life of the overall property from original expectations that are recoverable in regulatory rate base are capitalized while expenditures not meeting these criteria are expensed as incurred. The portion of

AFUDC attributable to borrowed funds is shown as a reduction of "Utility Interest Charges" in the consolidated statements of income. Any portion of AFUDC attributable to equity funds would be included in "Other Income (Expense)" in the consolidated statements of income. The costs of property retired are removed from utility plant and charged to accumulated depreciation. AFUDC for the years ended October 31, 2010, 2009 and 2008 is presented below.

In thousands	2010	2009	2008
AFUDC	$ 9,981	$ 2,298	$ 4,002

At this time, we have delayed proceeding with work on the Robeson County liquefied natural gas (LNG) peak storage facility given the slowing of our market growth due to current economic conditions. As conditions improve and additional supply is required for this growth, we will evaluate the timing for this project. Also, while not satisfying any future market supply requirements, the Sutton facilities will help serve our near term system pressure requirements in a cost effective manner in the eastern part of North Carolina. The timing and design scope of the expansion of our facilities in this area will be determined as our system infrastructure and market supply growth requirements in North Carolina dictate. In accordance with utility accounting practice, we have classified expenditures associated with the LNG facility as "Plant held for future use" in the consolidated balance sheets.

We compute depreciation expense using the straight-line method over periods ranging from four to 88 years. The composite weighted-average depreciation rates were 3.20% for 2010, 3.25% for 2009 and 3.23% for 2008.

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. Our last depreciation study was completed using fiscal year 2004 data, and new depreciation rates were approved effective November 1, 2005. We are currently engaged in a depreciation study using fiscal year 2009 data. Completion of the study is expected in early 2011, at which time the results will be filed with the appropriate regulatory authorities. No such five-year requirement exists in South Carolina or Tennessee; however, we periodically propose revised rates in those states based on depreciation studies. We collect through rates the estimated costs of removal on certain regulated properties through depreciation expense, with a corresponding credit to accumulated depreciation. Our approved depreciation rates are comprised of two components, one based on average service life and one based on cost of removal for certain regulated properties. Therefore, through depreciation expense, we accrue estimated non-legal costs of removal on any depreciable asset that includes cost of removal in its depreciation rate.

D. Asset Retirement Obligations.

The accounting guidance for AROs 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 assets. The accounting guidance requires the recognition of the fair value of a liability for AROs 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 the accounting guidance. Because these estimated removal costs meet the requirements of rate regulated accounting guidance, we have accounted for these non-legal AROs as a regulatory liability. We record the estimated non-legal AROs in "Cost of removal obligations" in "Noncurrent 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 accounting guidance for conditional AROs that requires recognition of a liability for the fair value of conditional AROs when incurred if the liability can be reasonably estimated. AROs will be capitalized concurrently by increasing the carrying amount of the related asset by the same amount as 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 conditional AROs must be recognized. The estimated cash flows to settle conditional AROs are discounted using the credit adjusted risk-free rate, which ranged from 5.87% to 5.12% with a weighted average of 5.87% as of October 31, 2010. The estimate was calculated using a time value weighted average credit adjusted risk-free rate. 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, 2010 and 2009 are presented below.

In thousands	2010	2009
Regulatory non-legal AROs	$ 412,776	$ 385,624
Conditional AROs	23,296	23,331
Total cost of removal obligations	$ 436,072	$ 408,955

A reconciliation of the changes in conditional AROs for the year ended October 31, 2010 and 2009 is presented below.

In thousands	2010	2009
Beginning of period	$ 23,331	$ 8,148
Liabilities incurred during the period	137	1,368
Liabilities settled during the period	(1,141)	(1,480)
Accretion	1,350	702
Adjustment to estimated cash flows	(382)	14,593
End of period	$ 23,295	$ 23,331

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. Pursuant to orders issued by the North Carolina Utilities Commission (NCUC) and the Public Service Commission of South Carolina (PSCSC), we are authorized to recover all uncollected gas costs through the purchased gas adjustment (PGA). 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. In Tennessee, 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 Actual Cost Adjustment (ACA) filings. Non-regulated merchandise and service work receivables due beyond one year are included in "Other" in "Noncurrent Assets" in the consolidated balance sheets.

Our principal business activity is the distribution of natural gas. We believe that we have provided an adequate allowance for any receivables which may not be ultimately collected. As of October 31, 2010 and 2009, our trade accounts receivable consisted of the following.

In thousands	2010	2009
Gas receivables	$ 60,823	$ 69,386
Non-regulated merchandise and service work receivables	2,476	2,583
Allowance for doubtful accounts	(929)	(990)
Trade accounts receivable	$ 62,370	$ 70,979

A reconciliation of the changes in the allowance for doubtful accounts for the years ended October 31, 2010, 2009 and 2008 is presented below.

In thousands	2010	2009	2008
Balance at beginning of year	$ 990	$ 1,066	$ 544
Additions charged to uncollectibles expense	4,886	5,570	5,308
Accounts written off, net of recoveries	(4,947)	(5,646)	(4,786)
Balance at end of year	$ 929	$ 990	$ 1,066

F. Fair Value Measurements

Our financial assets and liabilities are recorded at fair value. They consist primarily of derivatives that are recorded in the consolidated balance sheets in accordance with derivative accounting standards. The adoption of the fair value guidance for our financial assets and liabilities on November 1, 2008 had no impact on our financial position, results of operations or cash flows. There was no cumulative effect adjustment to retained earnings as a result of the adoption. Effective November 1, 2009, we adopted the additional authoritative guidance related to nonrecurring fair value guidance for certain nonfinancial assets and liabilities, such as the initial measurement of an ARO and the use of fair value in the impairment testing of goodwill, intangible assets and long-lived assets. In addition, in February 2010, we adopted the amended fair value guidance, which clarified disclosure requirements for fair value measurements and requires disclosure of transfers between Levels 1, 2 or 3. The adoption of the additional fair value guidance had no material impact on our financial position, results of operations or cash flows. As of October 31, 2010, in accordance with new accounting guidance for employers' disclosures about plan assets of defined benefit pension and other postretirement plans, the plan assets of our benefit plans are classified within the fair value hierarchy by asset allocation.

The carrying value of cash and cash equivalents, receivables, bank debt, accounts payable and accrued interest approximates fair value.

We utilize market data or assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally observable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we use valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The fair value of our financial assets and liabilities are subject to potentially significant volatility based on changes in market prices, the portfolio valuation of our contracts, as well as the maturity and settlement of those contracts, and subsequent newly originated transactions, each of which directly affects the estimated fair value of our financial instruments. We are able to classify fair value balances based on the observance of those inputs into the following fair value hierarchy levels as set forth in the fair value guidance.

Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that we have the ability to access as of the reporting date. Active markets have sufficient frequency and volume to provide pricing information for the asset or liability on an ongoing basis. Our Level 1 items consist of financial instruments of exchange-traded derivatives, investments in marketable securities and benefit plan assets held in registered investment companies and individual stocks.

Level 2 inputs are inputs other than quoted prices in active markets included in Level 1 and are either directly or indirectly corroborated or observable as of the reporting date, generally using valuation methodologies. Our Level 2 items include non-exchange-traded derivative instruments, such as over-the-counter (OTC) options and some qualified pension plan assets held in hedge fund of funds, swaps, futures, currency forwards, corporate bonds and government and agency obligations that are valued at the closing price reported in the active market for similar assets in which the individual securities are traded or based on yields currently available on comparable securities of issuers with similar credit ratings or based on the most recent available financial information for the respective funds and securities. For some qualified pension plan assets, the determination of Level 2 assets was completed through a process of reviewing each individual security while consulting research and other metrics provided by investment managers, including a pricing matrix detailing the pricing source and security type, annual audited financial statements and valuation policies and procedures.

Level 3 inputs include significant pricing inputs that are generally less observable from objective sources and may be used with internally developed methodologies that result in management's best estimate of fair value. Our Level 3 inputs include cost estimates for removal (contract fees or manpower/equipment estimates), inflation factors, risk premiums, the remaining life of long-lived assets, the credit adjusted risk free rate to discount for the time value of money over an appropriate time span, and the most recent available financial information of an investment in a hedge fund of funds and diversified private equity fund of funds for some of our qualified pension plan assets. We do not have any other assets or liabilities classified as Level 3.

Significant transfers between Level 1 and Level 2 are determined based on the transfer in relation to the total assets invested. These transfers represent existing assets or liabilities previously categorized as a higher level for which the inputs to the estimate became less observable or assets and liabilities previously classified as Level 2 or Level 3 for which the lowest significant input became more observable during the period. Transfers into and out of each level are measured at the end of the reporting period.

For the fair value measurements of our derivatives and marketable securities, see Note 6 to the consolidated financial statements. For the fair value measurements of our benefit plan assets, see Note 8 to the consolidated financial statements.

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

All of our goodwill is attributable to the regulated utility segment. We annually evaluate goodwill for impairment 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 as of October 31, 2010, 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, 2010, 2009 and 2008.

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, 2010, 2009 and 2008 that resulted in any impairment charges. For further information on equity method investments, see Note 11 to the consolidated financial statements.

H. Unamortized Debt Expense.

Unamortized debt expense consists of costs, such as underwriting and broker dealer fees, discounts and commissions, legal fees, accountant fees, registration fees and rating agency fees, related to issuing long-term debt and the short-term syndicated revolving credit facility. We amortize long-term 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. We amortize bank debt expense over the life of the syndicated revolving credit facility, which is five years.

I. 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.

We utilize asset management agreements with counterparties for certain natural gas storage and transportation assets. At October 31, 2010 and 2009, such counterparties held natural gas storage assets, included in "Prepayments" in the consolidated balance sheets, with a value of $36.6 million and $40.2 million, respectively, through capacity release and agency relationships. Under the terms of the asset management agreements, we receive capacity and storage asset management fees, which are recorded as secondary market transactions and shared between our utility customers and our shareholders. The asset management agreements expire at various times through March 31, 2011.

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

J. Deferred Purchased Gas Adjustments.

Rate schedules for utility sales and transportation customers include 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 wholesale cost of gas. Under PGA provisions, charges to cost of gas are based on the amount 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.

K. Marketable Securities.

We have marketable securities that are invested in money market and mutual funds that are liquid and actively traded on the exchanges. These securities are assets that are held in a rabbi trust established for our deferred compensation plans that became effective on January 1, 2009. For further information on the deferred compensation plans, see Note 8 to the consolidated financial statements.

We have classified these marketable securities as trading securities since their inception as the assets are held in a rabbi trust. Trading securities are recorded at fair value on the consolidated balance sheets with any gains or losses recognized currently in earnings. We do not intend to engage in active trading of the securities, and participants in the deferred compensation plans may redirect their investments at any time. The balance in a participant's account that exceeds $25,000 will be paid over five years upon retirement. A lesser amount will be paid upon retirement in a lump sum. We have matched the current portion of the deferred compensation liability with the current asset and the noncurrent deferred compensation liability with the noncurrent asset; the current portion has been included in "Other current assets" in the consolidated balance sheets.

The money market investments in the trust approximate fair value due to the short period of time to maturity. The fair values of the equity securities are based on quoted market prices as traded on the exchanges. The composition of these securities as of October 31, 2010 and 2009 is as follows.

In thousands	2010		2009	
	Cost	Fair Value	Cost	Fair Value
Current trading securities				
Money markets	$ -	$ -	$ -	$ -
Mutual funds	4	5	-	-
Total current trading securities	4	5	-	-
Noncurrent trading securities				
Money markets	254	254	169	169
Mutual funds	618	743	205	272
Total noncurrent trading securities	872	997	374	441
Total trading securities	$ 876	$ 1,002	$ 374	$ 441

L. 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, deferred gas costs, revenues and cost of gas, equity method investments, benefit of loss carryforwards and employee benefits and compensation. 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 in accordance with rate-regulated accounting provisions, 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 and energy tax credits to income over the estimated useful lives of the property to which the credits relate.

Excise taxes, sales taxes and franchises fees separately stated on customer bills are recorded on a net basis as liabilities payable to the applicable jurisdictions. All other taxes other than income taxes are recorded as general taxes. General taxes consist of property taxes, payroll taxes, Tennessee gross receipt taxes, franchise taxes, tax on company use, public utility fees and other miscellaneous taxes.

M. 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. In South Carolina and Tennessee, a weather normalization adjustment (WNA) is calculated for residential and commercial customers during the winter heating season November through March. The WNA is designed to offset the impact that warmer-than-normal or colder-than-normal weather has on customer billings during the winter heating season. In North Carolina, a margin decoupling mechanism provides for the recovery of our approved margin from residential and commercial customers independent of consumption patterns. The gas cost portion of our costs is recoverable through PGA procedures and is not affected by the WNA or the margin decoupling mechanism.

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 margin decoupling mechanism, as applicable.

Secondary market revenues associated with the commodity are recognized when the physical sales are delivered based on contract or market prices. Asset management fees for storage and transportation remitted on a monthly basis are recognized as earned given the monthly capacity costs associated with the contracts involved. Asset management fees remitted in a lump sum are deferred and amortized ratably into income over the period over which they are earned, which is typically the contract term. See Note 2 to the consolidated financial statements regarding revenue sharing of secondary market transactions.

Utility sales, transportation and secondary market revenues are reported on a net of tax basis. For further information, see Note 1.L to the consolidated financial statements.

N. Earnings Per Share.

We compute basic earnings per share (EPS) using the weighted average number of shares of common stock outstanding during each period. A reconciliation of basic and diluted EPS for the years ended October 31, 2010, 2009 and 2008 is presented below.

In thousands except per share amounts	2010	2009	2008
Net Income	$ 141,954	$ 122,824	$ 110,007
Average shares of common stock outstanding for basic earnings per share	72,275	73,171	73,334
Contingently issuable shares under incentive compensation plans	250	290	278
Average shares of dilutive stock	72,525	73,461	73,612
Earnings Per Share:			
Basic	$ 1.96	$ 1.68	$ 1.50
Diluted	$ 1.96	$ 1.67	$ 1.49

O. 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.

P. 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.

Q. Recently Issued Accounting Guidance.

In December 2008, the Financial Accounting Standards Board (FASB) issued new accounting guidance for employers' disclosures about plan assets of defined benefit pension and other postretirement plans. This guidance requires that employers provide more transparency about the assets held by retirement plans or other postretirement employee benefit plans, the concentration of risk in those plans and information about the fair value measurements of plan assets similar to the disclosures required by current fair value guidance. The guidance is effective for fiscal years ending after December 15, 2009. Since only additional disclosures about plan assets of defined benefit pension and other postretirement plans are required, the adoption of this guidance, as of October 31, 2010, had no impact on our financial position, results of operations or cash flows. For information regarding these disclosures, see Note 8 to the consolidated financial statements.

In June 2009, the FASB amended accounting guidance to eliminate the quantitative approach that entities use to determine whether an entity has a controlling financial interest in a variable interest entity (VIE) and to require that the entity with a variable interest in a VIE qualitatively assess whether it has a controlling financial interest, and if so, determine whether it is the primary beneficiary. The guidance requires companies to continually evaluate the VIE for consolidation, rather than performing the assessment only when specific events occur. It also requires enhanced disclosures to provide more information about the entity's involvement with the VIE. The guidance is effective for fiscal periods beginning after November 15, 2009. Our adoption of this guidance on consolidation of variable interest entities, effective November 1, 2010, is not expected to have a material impact on our financial position, results of operations or cash flows.

In January 2010, the FASB issued accounting guidance to require new fair value measurement and classification disclosures and to clarify existing disclosures. The guidance requires disclosures about transfers into and out of Levels 1 and 2 of the fair value hierarchy and separate disclosures about purchases, sales, issuances and settlements relating to Level 3 measurements. It also clarifies the existing fair value disclosures about the level of disaggregation and about inputs and valuation techniques used to measure fair value and amends guidance on employers' disclosures about postretirement benefit plan assets to require disclosures be provided by asset class instead of major categories of assets. The guidance was effective for interim and fiscal periods beginning after December 15, 2009, with the exception that the Level 3 activity disclosure requirement will be effective for interim periods for fiscal years beginning after December 15, 2010. Since the guidance addresses only disclosure related to fair value measurements, adoption of the guidance during our fiscal second quarter beginning February 1, 2010 did not have a material impact on our financial position, results of operations or cash flows. We will adopt the guidance for Level 3 disclosure for recurring and non-recurring items covered under the fair value guidance for the first quarter of our fiscal year ending October 31, 2012. Since the guidance addresses only disclosures related to fair value measurements under Level 3, we do not expect the adoption of this guidance to have a material impact on our financial position, results of operations or cash flows.

In July 2010, the FASB issued accounting guidance to improve disclosures related to an entity's allowance for credit losses and the credit quality of its financing receivables, excluding short-term trade accounts receivable or receivables measured at fair value or cost if lower than fair value. The guidance requires additional disclosures about financing receivables such as the credit quality indicators, the aging of past due financing receivables, the nature and extent of troubled debt restructurings, any modifications of financing receivables as troubled debt restructurings and the related effect on the allowance for credit losses and any significant purchases or sales of financing receivables during the reporting period. End of reporting period disclosures are required for the reporting period ending on or after December 15, 2010. The disclosures about activity that occurred during a reporting period are effective for interim and annual periods beginning on or after December 15, 2010. Comparative disclosure for earlier reporting periods is encouraged but not required. We will adopt the guidance for the end of period disclosures as of January 31, 2011, and for the disclosures related to activity in the reporting period during our fiscal second quarter beginning February 1, 2011. Since the guidance addresses only disclosures related to credit quality of financing receivables and the allowance for credit losses, we do not expect the adoption of this guidance to have a material impact on our financial position, results of operations or cash flows.

2. Regulatory Matters

Our utility operations are regulated by the NCUC, PSCSC and 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.

In March 2008, we filed a general rate case proceeding with the NCUC requesting an increase in rates and charges for all customers to produce overall increased annual revenues of $40.5 million, or 4% above the current annual revenues. In October 2008, the NCUC approved a settlement between us, the North Carolina Public Staff and all intervening parties with the exception of the North Carolina Attorney General's office, in which the parties agreed to an annual revenue increase of $15.7 million and the continuation of the margin decoupling mechanism that provides for the recovery of our approved margin from residential and commercial customers independent of consumption patterns. Initially, the margin decoupling mechanism was experimental for a three-year period beginning in 2005, subject to semi-annual reviews and approval for extension in a future general rate case. In addition to the revenue increase, the stipulation also included cost allocation and rate design changes under our existing rate schedules, approval to implement energy conservation and efficiency programs of $1.3 million annually with appropriate cost recovery mechanisms and changes to existing service regulations and tariffs. The new rates became effective November 1, 2008.

Since the inception of the North Carolina energy conservation program on November 1, 2005, we have incurred charges of $6.4 million for the benefit of residential and commercial customers. The charges consist of $3.75 million for the funding of conservation programs in North Carolina, $2.25 million for the reduction of residential and commercial customer rates in North Carolina and $.4 million for interest accruals on the conservation funding and reduction of customer rates. At October 31, 2010 and 2009, we had liabilities for the conservation programs of $.4 million and $1.1 million, respectively.

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 Eastern North Carolina Natural Gas Company (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 feasibility of providing service and 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. With a 2003 acquisition and subsequent merger of EasternNC into our regulated utility segment, we are required to provide an accounting of the operational feasibility of this area to the NCUC every two years. Should this operational area become economically feasible and generate a profit, we would begin to repay the state bond funding.

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 2005 general rate case proceeding, 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. Under the settlement of the 2008 general rate proceeding, the unamortized balance of the EasternNC deferred operations and maintenance expenses was $9 million at October 31, 2008. This balance is being amortized over a twelve-year period and is accruing interest at a rate of 7.84% per annum.

We incur certain pipeline integrity management costs 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, the balance of $.4 million in the deferred account as of June 30, 2005 was amortized over three years beginning November 1, 2005, and subsequent expenditures that totaled $4.3 million as of October 31, 2007 were deferred. Under the settlement of the 2008 general rate proceeding, the pipeline integrity management costs incurred between July 1, 2005 and June 30, 2008 of $4.6 million are being amortized over a three-year period beginning November 1, 2008. The existing regulatory asset treatment for ongoing pipeline integrity management costs will continue until another recovery mechanism is established in a future rate proceeding. The balance as of October 31, 2010 that is not being amortized that is subject to a future rate proceeding is $5.2 million.

We currently operate under the Natural Gas Rate Stabilization Act (RSA) of 2005 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 RSA, the annual filing will provide that the utility's rate of return on equity will remain within a 50-basis point band above or below the current allowed rate of return on equity.

In June 2008, we filed with the PSCSC a quarterly monitoring report for the twelve months ended March 31, 2008 and a cost and revenue study as permitted by the RSA requesting a change in rates from those approved by the PSCSC in the October 2007 order. In October 2008, the PSCSC issued an order approving a settlement between the Office of Regulatory Staff (ORS), the South Carolina Energy Users Committee (SCEUC) and us that resulted in a $1.5 million annual decrease in margin based on a return on equity of 11.2%, effective November 1, 2008.

In June 2009, we filed with the PSCSC a quarterly monitoring report for the twelve months ended March 31, 2009 and a cost and revenue study as permitted by the RSA requesting a change in rates from those approved by the PSCSC in the October 2008 order. In October 2009, the PSCSC issued an order approving a settlement between the ORS, the SCEUC and us that resulted in a $1.1 million annual increase in margin based on a return on equity of 11.2%, effective November 1, 2009.

In June 2010, we filed with the PSCSC a quarterly monitoring report for the twelve months ended March 31, 2010 and a cost and revenue study as permitted by the RSA requesting a change in rates from those approved by the PSCSC in the October 2009 order. In October 2010, the PSCSC issued an order approving a settlement between the ORS, the SCEUC and us that resulted in a $.75 million annual increase in margin on a return on equity of 11.3%, effective November 1, 2010.

The NCUC and the PSCSC regulate our gas purchasing practices under a standard of prudence and audit our gas cost accounting practices. The TRA regulates our gas purchasing practices under a gas supply incentive program which compares our actual costs to market pricing benchmarks. As part of this jurisdictional oversight, all three states address our gas supply hedging activities. Additionally, North Carolina and South Carolina allow for recovery of uncollectible gas costs through the PGA. 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 Tennessee, 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.

In North Carolina, our recovery of gas costs is subject to annual gas cost proceedings to determine the prudence of our gas purchases. Costs have never been disallowed on the basis of prudence.

During 2007, under the provisions of the August 2007 NCUC order, we recorded as restricted cash $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 deferred account. The various certificates of deposit matured by January 31, 2008.

In February 2009, the NCUC approved our accounting of gas costs for the twelve months ended May 31, 2008, with adjustments agreed to by us as a result of the North Carolina Public Staff's audit of the 2008 gas cost review period. We were deemed prudent on our gas purchasing policies and practices during this review period and allowed 100% recovery.

In February 2010, the NCUC approved our accounting of gas costs for the twelve months ended May 31, 2009, with adjustments agreed to by us as a result of the North Carolina Public Staff's audit of the 2009 gas cost review period. We were deemed prudent on our gas purchasing policies and practices during this review period and allowed 100% recovery.

In July 2010, we filed testimony with the NCUC in support of our gas cost purchasing and accounting practices for the twelve months ended May 31, 2010. A hearing was held on October 5, 2010. We are unable to predict the outcome of this proceeding at this time.

Our gas cost hedging plan for North Carolina is designed for the purpose of cost stabilization, targets a percentage range 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 recognized under the hedging program is a reduction in or an addition to gas costs, respectively, which, along with any hedging expenses, are flowed through to North Carolina customers in rates. The gas cost review orders issued February 2009 and 2010 found our hedging activities during the review periods to be reasonable and prudent. In 2009, as a part of our North Carolina annual cost review proceeding for the twelve months ended May 31, 2009, the NCUC approved an adjustment of $1.1 million related to hedging activity as reflected in "Amounts due from customers" as agreed to by us and the North Carolina Public Staff.

In South Carolina, our recovery of gas costs is subject to annual gas cost proceedings to determine the prudence of our gas purchases. Costs have never been disallowed on the basis of prudence.

In August 2008, the PSCSC approved our PGAs and found our gas purchasing policies to be prudent for the twelve months ended March 31, 2008.

In August 2009, the PSCSC approved our PGAs and found our gas purchasing policies to be prudent for the twelve months ended March 31, 2009.

In August 2010, the PSCSC approved our PGAs and found our gas purchasing policies to be prudent for the twelve months ended March 31, 2010.

The PSCSC has approved a gas cost hedging plan for the purpose of cost stabilization for South Carolina customers. The plan targets a percentage range 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 recognized under the hedging program is a reduction in or an addition to gas costs, respectively, and are flowed through to South Carolina customers in rates.

In October 2009, we filed a petition with the PSCSC requesting approval to offer three energy efficiency programs to residential and commercial customers at a total annual cost of $.35 million. The proposed programs in South Carolina were designed to promote energy conservation and efficiency by residential and commercial customers with full ratepayer recovery of program costs through annual RSA filings and were similar to approved energy efficiency programs in North Carolina. In May 2010, the PSCSC approved the energy efficiency programs on a three-year experimental basis with equipment rebates on the purchase of high-efficiency natural gas equipment and weatherization assistance for low-income residential customers.

In Tennessee, the Tennessee Incentive Plan (TIP) replaced annual prudence reviews under the 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. In 2007, the TRA modified our TIP to clarify and simplify the calculation of allocated gains and losses to ratepayers and shareholders by adopting a uniform 75/25 sharing ratio, maintain the $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.

We filed an annual report for the twelve months ended December 31, 2006 with the TRA that reflected the transactions in the deferred gas cost account for the ACA mechanism. In June 2008, the TRA staff filed its final audit report, with which we concurred. In August 2008, the TRA issued an order adopting all findings from the staff audit. The order included cost of gas adjustments for the calendar year 2006 review period. There was no material impact from these gas cost adjustments on our financial position, results of operations or cash flows.

In December 2008, we filed an annual report for the twelve months ended December 31, 2007 with the TRA that reflected the transactions in the deferred gas cost account for the ACA mechanism. In April 2009, the TRA staff filed its final audit report, with which we concurred. In May 2009, the TRA issued an order adopting all findings from the staff audit. The order included cost of gas adjustments for the calendar year 2007 review period. There was no material impact from these gas cost adjustments on our financial position, results of operations or cash flows. We were found to be in compliance with the TRA rules in the use of the ACA mechanism.

In July 2009, we filed an annual report for the twelve months ended December 31, 2008 with the TRA that reflected the transactions in the deferred gas cost account for the ACA mechanism. In July 2010, in coordination with the TRA Audit Staff, we withdrew the annual report filed in July 2009 and concurrently filed a revised annual report for the twelve months ended December 31, 2008. There was no material impact from these gas cost adjustments on our financial position, results of operations or cash flows. In October 2010, the TRA issued its order adopting the findings of the revised TRA Audit Staff report on this matter, which were in agreement with our revised report.

In December 2010, we filed our report for the eighteen months ended June 30, 2010 with the TRA that reflected the transactions in the deferred gas cost account for the ACA mechanism. This one-time eighteen month audit period is designed to synchronize the ACA audit year with the TIP year in order to facilitate the audit process for future periods. We are unable to predict the outcome of this proceeding at this time.

In July 2009, we filed a petition with the TRA requesting approval to decouple residential rates in Tennessee and to offer three energy efficiency programs to residential customers. We proposed a margin decoupling tracker mechanism that was designed to allow us to recover from our residential customers the approved per customer margin as approved in our last general rate proceeding. The proposed energy efficiency programs in Tennessee were designed to promote energy conservation and efficiency by residential customers and were similar to approved energy efficiency programs in North Carolina. In August 2009, the TRA suspended the tariff and established a contested case to address the filing. A hearing on our requests was held in December 2009. In January 2010, the TRA denied our petition without prejudice to us refiling a margin decoupling tracker mechanism (or other similar mechanism) and energy efficiency programs for residential customers in a future general rate proceeding.

In February 2010, we filed a petition with the TRA to adjust the applicable rate for the collection of the Nashville franchise fee from certain customers. The proposed rate adjustment was calculated to recover the net $2.9 million of under-collected Nashville franchise fee payments as of May 31, 2009. In April 2010, the TRA passed a motion approving a new Nashville franchise fee rate designed to recover only the net under-collections that have accrued since June 1, 2005, which would deny recovery of $1.5 million for us. Once the TRA issues its order on this matter, we intend to seek their reconsideration. We are unable to predict the outcome of this proceeding at this time. However, we do not believe this matter will have a material effect on our financial position, results of operations or cash flows.

In September 2010, we filed a petition with the TRA requesting deferred accounting treatment for the direct, incremental expenses incurred as a result of our response to the severe flooding in Nashville in May 2010. The TRA approved our petition in October 2010. As of October 31, 2010, the balance in the deferred account is $1 million.

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. In all three jurisdictions for the twelve months ended October 31, 2010, we generated $42.8 million of margin from secondary market activity, $32.1 million of which was allocated to customers as gas cost reductions and $10.7 million as margin allocated to us.

The NCUC, the PSCSC and the TRA approved our 2006 request to place certain defined benefit postretirement obligations related to the implementation of accounting guidance for employers' accounting for defined benefit pension and other postretirement plans in a deferred account instead of OCI. Also in 2006, as a result of adopting accounting guidance for conditional AROs, the placing of certain ARO costs in deferred accounts to preserve the regulatory treatment for these costs was approved in all jurisdictions.

We currently have commission approval in all three states that place tighter 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.

3. Long-Term Debt

All of our long-term debt is unsecured and is issued at fixed rates. Long-term debt as of October 31, 2010 and 2009 is as follows.

In thousands	2010	2009
Senior Notes:		
8.51%, due 2017	$ 35,000	$ 35,000
Medium-Term Notes:		
7.80%, due 2010	-	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
Insured Quarterly Notes:		
6.25%, due 2036	196,922	197,512
Total	731,922	792,512
Less current maturities	60,000	60,000
Total	$ 671,922	$ 732,512

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

In thousands	
2011	$ 60,000
2012	-
2013	-
2014	100,000
2015	-
Thereafter	571,922
Total	$ 731,922

Payments of $.6 million and $1.7 million in 2010 and 2009, respectively, were 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. We retired the balance of $60 million of our 7.8% medium-term notes and $30 million of our 7.35% medium-term notes in September 2010 and September 2009, respectively, as they became due.

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, 2010, our retained earnings were not restricted as the amount available for restricted payments was greater than our actual retained earnings as presented below.

In thousands	
Amount available for restricted payments	$ 591,595
Retained earnings	519,831

We are subject to default provisions related to our long-term debt and short-term debt. Since there are cross-default provisions in all of our debt agreements, failure to satisfy any of the default provisions may result in total outstanding issues of debt becoming due. As of October 31, 2010, we are in compliance with all default provisions.

4. Short-Term Debt Instruments

We have a syndicated five-year revolving credit facility that expires April 2011 with aggregate commitments totaling $450 million to meet working capital needs, capital expenditures and approved acquisitions. This facility may be increased up to $600 million and includes annual renewal options and letters of credit. We pay an annual fee of $35,000 plus six basis points for any unused amount up to $450 million. The facility provides a line of credit for letters of credit of $5 million, of which $2.7 million and $2.4 million were issued and outstanding at October 31, 2010 and 2009, respectively. These letters of credit are used to guarantee claims from self-insurance under our general and automobile liability policies. The credit facility bears interest based on the 30-day LIBOR rate plus from 15 to 35 basis points, based on our credit ratings. Amounts borrowed remain outstanding until repaid and such amounts do not mature daily. Due to the seasonal nature of our business, amounts borrowed can vary significantly during the year.

Effective December 3, 2008, we entered into a syndicated seasonal credit facility with aggregate commitments totaling $150 million. Advances under this seasonal facility bore interest at a rate based on the 30-day LIBOR rate plus from 75 to 175 basis points, based on our credit ratings. This seasonal credit facility expired on March 31, 2009. We entered into this facility to provide lines of credit in addition to the syndicated five-year revolving credit facility discussed above in order to have additional resources to meet seasonal cash flow requirements and general corporate needs. This seasonal credit facility replaced the two short-term credit facilities with banks for unsecured commitments totaling $75 million that were effective from October 27 and 29, 2008 through December 3, 2008, bearing interest at the same rate as the seasonal facility.

As of October 31, 2010 and 2009, outstanding short-term borrowings under our syndicated five-year revolving credit facility as included in "Bank debt" in the consolidated balance sheets were $242 million and $306 million, respectively, in LIBOR cost-plus loans at a weighted average interest rate of .50% in 2010 and .85% in 2009. During the twelve months ended October 31, 2010, short-term borrowings ranged from zero to $342.5 million, and interest rates ranged from .48% to .61% when borrowing. Our syndicated five-year revolving credit facility's financial covenants require us to maintain a ratio of total debt to total capitalization of no greater than 70%, and our actual ratio was 50% at October 31, 2010.

5. Capital Stock and Accelerated Share Repurchase

Changes in common stock for the years ended October 31, 2010, 2009 and 2008 are as follows.

In thousands	Shares	Amount
Balance, October 31, 2007	74,208	$ 497,570
Issued to participants in the Employee Stock Purchase Plan (ESPP)	33	838
Issued to the Dividend Reinvestment and Stock Purchase Plan (DRIP)	567	14,753
Issued to participants in the Executive Long-Term Incentive Plan (LTIP)	40	1,082
Shares repurchased under Common Stock Open Market Repurchase Plan	(1,000)	(26,139)
Shares repurchased under Accelerated Share Repurchase (ASR) Plan	(602)	(16,539)
Balance, October 31, 2008	73,246	471,565
Issued to ESPP	37	875
Issued to DRIP	565	13,560
Issued to LTIP	89	2,755
Issued to participants in the Incentive Compensation Plan (ICP)	29	671
Shares repurchased under ASR Plan	(700)	(17,857)
Balance, October 31, 2009	73,266	471,569
Issued to ESPP	35	899
Issued to DRIP	676	17,663
Issued to ICP	106	2,804
Shares repurchased under ASR Plan	(1,800)	(47,276)
Shares repurchased under Rescission Offer	(1)	(19)
Balance, October 31, 2010	72,282	$ 445,640

In June 2004, the Board of Directors approved a Common Stock Open Market Purchase Program that authorized the repurchase of up to three million shares of currently outstanding shares of common stock. We implemented the program in September 2004. 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 repurchase 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 were referred to as our ASR program with an expiration date of December 31, 2010. On March 6, 2009, the Board of Directors authorized the repurchase of up to an additional four million shares under the Common Stock Open Market Purchase Program and the ASR program, which were consolidated. 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.

In January 2010, we began to purchase and retire 1.8 million shares of our common stock under the Common Stock Open Market Purchase Plan. We repurchased 1.4 million shares for $36.9 million and .4 million shares for $10.4 million in January 2010 and February 2010, respectively, at an average share price of $26.26. Total consideration paid of $47.3 million to purchase the shares was recorded in "Stockholders' equity" as a reduction in "Common stock" in the consolidated balance sheets.

As of October 31, 2010, 4.6 million shares of common stock were reserved for issuance as follows.

In thousands	
ESPP	303
DRIP	2,088
LTIP and ICP	2,221
Total	4,612

On November 16, 2009, we discovered in fiscal 2009 and early fiscal 2010 that we had inadvertently sold more shares under our DRIP than were registered with the Securities and Exchange Commission (SEC) and authorized by our Board of Directors for issuance under the DRIP. We also discovered that the registration statement we believed had registered shares issued under the DRIP between December 1, 2008 and November 16, 2009 had expired for some of those shares. As a result, from November 1, 2009 through November 16, 2009, we sold 15,029 shares under the DRIP that may not have been registered at the time of issuance for proceeds of $347,000. Our Board of Directors ratified the authorization and issuance of the excess number of shares, and on November 20, 2009, we filed a registration statement covering the sale and issuance of an additional 2.75 million shares of our common stock under the DRIP. On February 8, 2010, we filed a registration statement (Rescission Offer) which offered to rescind the purchase of the shares sold under the DRIP between December 1, 2008 and November 16, 2009 and registered all previously unregistered shares issued under the DRIP during that period. Under the Rescission Offer, the purchase of 711 shares was rescinded for an aggregate consideration of $18,900. We incurred costs related to the Rescission Offer of $.8 million, which have been recorded against retained earnings. We reported these events to the relevant regulatory authorities, including the SEC and the NCUC. The sale of unregistered securities could subject us to enforcement actions or penalties and fines by these regulatory authorities, though no regulatory action has been initiated. While we are unable to predict the full consequences of these events, we do not expect them to have a material adverse effect on us.

6. Financial Instruments and Related Fair Value

Derivative Assets and Liabilities under Master Netting Arrangements

We maintain brokerage accounts to facilitate transactions that support our gas cost hedging plans. Based on the value of our positions in these brokerage accounts and the associated margin requirements, we may be required to deposit cash into these accounts. The accounting guidance related to derivatives and hedging requires that we use a gross presentation for the fair value amounts for our derivative instruments and the fair value of the right to reclaim cash collateral. We include amounts recognized for the right to reclaim cash collateral in our current assets and current liabilities. We had no cash deposited in the brokerage accounts as of October 31, 2010, and we had the right to reclaim cash collateral of $35.4 million as of October 31, 2009.

Fair Value Measurements

We use financial instruments to mitigate commodity price risk for our customers. In developing our fair value measurements of these financial instruments, we utilize market data or assumptions about risk and the risks inherent in the inputs to the valuation technique. Fair value refers to the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the market in which the entity transacts. We are able to classify fair value balances based on the observance of those inputs into the fair value hierarchy levels as set forth in the fair value accounting guidance and fully described in Note 1.F.

The following table sets forth, by level of the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of October 31, 2010 and 2009. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their consideration with the fair value hierarchy levels. We have had no transfers between Level 1 and Level 2 during this fiscal year.

Recurring Fair Value Measurements as of October 31, 2010

In thousands	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value
Assets:				
Derivatives held for distribution operations	$ 2,819	$ -	$ -	$ 2,819
Debt and equity securities held as trading securities:				
Money markets	254	-	-	254
Mutual funds	748	-	-	748
Total fair value assets	$ 3,821	$ -	$ -	$ 3,821
Liabilities:				
Derivatives held for distribution operations	$ -	$ -	$ -	$ -

Recurring Fair Value Measurements as of October 31, 2009

In thousands	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value
Assets:				
Derivatives held for distribution operations	$ 2,559	$ -	$ -	$ 2,559
Debt and equity securities held as trading securities				
Money markets	169	-	-	169
Mutual funds	272	-	-	272
Total fair value assets	$ 3,000	$ -	$ -	$ 3,000
Liabilities:				
Derivatives held for distribution operations	$ 30,290	$ 313	$ -	$ 30,603

The determination of the fair values incorporates various factors required under the fair value guidance. These factors include the credit standing of the counterparties involved, the impact of credit enhancements (such as cash deposits, letters of credit and priority interests) and the impact of our nonperformance risk on our liabilities.

Our utility segment derivative instruments are used in accordance with programs filed with or approved by the NCUC, the PSCSC and the TRA to hedge the impact of market fluctuations in natural gas prices. These derivative instruments are accounted for at fair value each reporting period. In accordance with regulatory requirements, the net costs and the gains and losses related to these derivatives are reflected in purchased gas costs and ultimately passed through to customers through our PGA procedures. In accordance with accounting provisions for rate-regulated activities, the unrecovered amounts related to these instruments are reflected as a regulatory asset or liability, as appropriate, in "Amounts due to customers" or "Amounts due from customers" in our consolidated balance sheets. These derivative instruments include exchange-traded and OTC derivative contracts. Exchange-traded contracts are generally based on unadjusted quoted prices in active markets and are classified within Level 1. OTC derivative contracts are valued using broker or dealer quotation services or market transactions in either the listed or OTC markets and are classified within Level 2.

Trading securities include assets in a rabbi trust established for our deferred compensation plans and are included in "Marketable securities, at fair value" in the consolidated balance sheets. Securities classified within Level 1 include funds held in money market and mutual funds, which are highly liquid and are actively traded on the exchanges.

In developing the fair value of our long-term debt, we use a discounted cash flow technique, consistently applied, that incorporates a developed discount rate using long-term debt similarly rated by credit rating agencies combined with the U.S. Treasury bench mark with consideration given to maturities, redemption terms and credit ratings similar to our debt issuances. The carrying amount and fair value of our long-term debt, including the current portion, are shown below.

In thousands		Carrying Amount		Fair Value
As of October 31, 2010	$	731,922	$	890,277
As of October 31, 2009		792,512		910,310

Quantitative and Qualitative Disclosures

The costs of our financial price hedging options for natural gas and all other costs related to hedging activities of our regulated gas costs are recorded in accordance with our regulatory tariffs approved by our state regulatory commissions, and thus are not accounted for as hedging instruments under derivative accounting standards. As required by the accounting guidance, the fair value amounts are presented on a gross basis and do not reflect any netting of asset and liability amounts or cash collateral amounts under master netting arrangements. As of October 31, 2010, our financial options were comprised of long commodity positions and as of October 31, 2009, our financial options were comprised of both long and short commodity positions. A long position in an option contract is a right to purchase or sell the commodity at a specified price, while a short position in an option contract is the obligation, if the option is exercised, to purchase or sell the commodity at a specified price. As of October 31, 2010, we had long gas options providing total coverage of 33.5 million dekatherms. As of October 31, 2009, we had long options providing total coverage of 49.7 million dekatherms, of which 40.9 million dekatherms were limited in upside protection; we sold options for 25.4 million dekatherms that guaranteed a minimum floor price for supply. As of October 31, 2010, the long options are for the period from December 2010 through November 2011.

The following table presents the fair value and balance sheet classification of our financial options for natural gas as of October 31, 2010 and 2009.

Fair Value of Derivative Instruments

In thousands		Fair Value October 31, 2010		Fair Value October 31, 2009
Derivatives Not Designated as Hedging Instruments under Derivative Accounting Standards:				
Asset Financial Instruments				
Current Assets - Gas purchase derivative assets (December 2010 - November 2011)	$	2,819		
Current Assets - Gas purchase derivative assets (December 2009 - November 2010)			$	2,559
Liability Financial Instruments				
Current Liabilities - Gas purchase derivative liabilities (December 2009 - November 2010)				30,603
Total financial instruments, net	$	2,819	$	(28,044)

We purchase natural gas for our regulated operations for resale under tariffs approved by state regulatory commissions. We recover the cost of gas purchased for regulated operations through PGA procedures. Our risk management policies allow us to use financial instruments to hedge commodity price risks, but not for speculative trading. The strategy and objective of our hedging programs is to use these financial instruments to provide protection against significant price increases. Accordingly, the operation of the hedging programs on the regulated utility segment as a result of the use of these financial derivatives generally has no earnings impact.

The following table presents the impact that financial instruments not designated as hedging instruments under derivative accounting standards would have had on our consolidated statements of income for 2010 and 2009, absent the regulatory treatment under our approved PGA procedures.

In thousands	Amount of Loss Recognized on Derivatives Instruments				Amount of Loss Deferred Under PGA Procedures				Location of Loss Recognized through PGA Procedures
	Twelve Months Ended October 31,				Twelve Months Ended October 31,				
	2010		2009		2010		2009		
Gas purchase options	$	62,516	$	148,461	$	62,516	$	147,370	Cost of Gas

In Tennessee, the cost of these options and all other costs related to hedging activities up to 1% of total annual gas costs are approved for recovery under the terms and conditions of our TIP approved by the TRA. In South Carolina, the costs of these options are pre-approved by the PSCSC for recovery from customers subject to the terms and conditions of our gas hedging plan approved by the PSCSC. In North Carolina, costs associated with our hedging program are not pre-approved by the NCUC but are treated as gas costs subject to an annual cost review proceeding by the NCUC. In 2009, as a part of our North Carolina annual cost review proceeding for the twelve months ended May 31, 2009, we and the North Carolina Public Staff agreed to an adjustment of $1.1 million related to hedging activity as reflected in "Amounts due from customers," which was approved by the NCUC in February 2010.

Risk Management

Our OTC derivative financial instruments do not contain material credit-risk-related or other contingent features that could require us to make accelerated payments over and above payments made in the normal course of business when we are in a net liability position. At October 31, 2010 and October 31, 2009, we have five International Swaps and Derivatives Association (ISDA) agreements for the purpose of securing put options as a part of our overall hedging program. The ISDA agreements specify a total net liability of $162 million before we are obligated to post collateral. The net liability extended under the agreements is a function of the credit rating assigned to us by Standard & Poor's Ratings Services (S&P), which is currently A/stable. In the event of a downgrade in our S&P credit rating to A-, the net liability available to us would decline to $142 million before we would be obligated to post collateral. We have no outstanding positions under any ISDA agreement as of October 31, 2010 and $.3 million aggregate fair value of the derivative instruments that are in a net liability position as of October 31, 2009 for which we were not required to post collateral. These instruments are acquired under the provisions of our regulatory tariffs. Therefore, should credit-risk-related factors require us to deposit funds as collateral, these amounts would be handled in accordance with our hedging programs under the recovery mechanism filed with and allowed by each of our state regulators.

We seek to identify, assess, monitor and manage risk in accordance with defined policies and procedures under an Enterprise Risk Management Policy. In addition, we have an Energy Price Risk Management Committee that monitors compliance with our hedging programs, policies and procedures.

7. Commitments and Contingent Liabilities

Leases

We lease certain buildings, land and equipment for use in our operations under noncancelable operating leases. Operating lease payments for the years ended October 31, 2010, 2009 and 2008 are as follows.

In thousands	2010	2009	2008
Operating lease payments	$ 5,303	$ 6,173	$ 5,483

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

In thousands	
2011	$ 4,584
2012	4,468
2013	4,208
2014	4,158
2015	3,973
Thereafter	1,984
Total	$ 23,375

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 twenty-two years. The time periods for gas supply contracts range from one to two years. The time periods for the telecommunications and technology outsourcing contracts, maintenance fees for hardware and software applications, usage fees, local and long-distance costs and wireless service range from one to three 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 our right 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 statements of income as part of gas purchases and included in cost of gas.

As of October 31, 2010, future unconditional purchase obligations for the next five years ending October 31 and thereafter are as follows.

In thousands	Pipeline and Storage Capacity	Gas Supply	Telecommunications and Information Technology	Other	Total
2011	$ 150,914	$ 11,862	$ 15,316	$ 5,147	$ 183,239
2012	142,627	48	5,381	-	148,056
2013	97,553	12	67	-	97,632
2014	75,651	-	-	-	75,651
2015	68,093	-	-	-	68,093
Thereafter	348,995	-	-	-	348,995
Total	$ 883,833	$ 11,922	$ 20,764	$ 5,147	$ 921,666

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 $2.7 million in letters of credit that were issued and outstanding at October 31, 2010. Additional information concerning letters of credit is included in Note 4 to the consolidated financial statements.

Environmental Matters

Our three 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.

In October 1997, 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 $5.3 million, charged to the estimated environmental liability, that released us from any investigation and remediation liability. 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.

There are three other MGP sites located in Hickory, North Carolina, Nashville, Tennessee and Anderson, South Carolina that we have owned, leased or operated. 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 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 investigating the Hickory, North Carolina MGP site in 2007. Based on a limited site assessment report in 2007, we concluded that gas plant residuals remaining on the Hickory site were thought to be mostly contained within two former tar separators associated with the site's operations. During 2008, more extensive testing was conducted and completed, including soil investigation and phase 1 of the groundwater investigation. The soil investigation revealed that most of the site surface soils and a significant area of deep soils exceed the site specific cleanup standards, and phase 1 of the groundwater investigation revealed contamination from an underground storage tank (UST) and the MGP. A remedial work plan to remove the soil has been submitted and approved by the NCDENR. The removal of approximately 10,000 tons of MGP impacted soil and phase 2 groundwater investigation was initiated in April 2010 and completed in June 2010. During 2010, our estimate of the total cost to remediate the facility increased from $1 million to $1.3 million. In accordance with the deferral accounting authorized by our regulatory commissions, we adjusted the regulatory asset and the estimated liability for this additional $.3 million. We have incurred $1.3 million on this site through October 31, 2010. The state may require additional groundwater remediation after it reviews our phase 2 groundwater investigation report. If the state does not require any further action, we will then submit our final report with the state.

In September 2009, the NCDENR requested a remediation plan for the Reidsville, North Carolina MGP site. In January 2010, we submitted our plan to the NCDENR. In June 2010, we conducted our initial investigation which consisted of digging test pits and completing soil and groundwater contamination testing. Our estimate of the total cost to remediate the Reidsville site is $.8 million for which we have recorded a liability.

In November 2008, we submitted our final report of the remediation of the Nashville MGP holder site to the Tennessee Department of Environment and Conservation (TDEC). Remediation has been completed, and a consent order imposing usage restrictions on the property was approved and signed by the TDEC in June 2010. The consent order is subject to public comment, which we anticipate being completed in our first quarter of 2011. We have incurred $1.5 million through October 31, 2010 for this remediation.

In connection with the 2003 North Carolina Natural Gas Corporation (NCNG) acquisition, several MGP sites owned by NCNG were transferred to a wholly owned subsidiary of Progress Energy, Inc. (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 costs 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.

During 2008, we became aware of and began investigating several contamination concerns at our Huntersville LNG facility. One area of concern was where a molecular sieve had been buried and potentially contaminated with hydrocarbons and trichloroethylene. Additionally, groundwater at the property had trichloroethylene detected at levels which exceeded state standards. The Huntersville LNG facility also was originally coated with lead-based paint. The molecular sieve and the related contaminated soil were removed and properly disposed, and in June 2010, we received a determination letter from the NCDENR that no further soil remediation would be required for the Huntersville LNG molecular sieve issue. The facility uses groundwater for fire-fighting, and the supply well was equipped with filters to remove any chlorinated solvents. As a precautionary measure to ensure that no lead contamination occurs, removal of lead-based paint from the site was initiated in spring 2010. Based on the activities mentioned above, during 2010, our estimate of the total cost to remediate the facility increased from $1.6 million to $3.1 million. In accordance with the deferral accounting authorized by our regulatory commissions, we adjusted the regulatory asset and the estimated liability for this additional $1.5 million. We have incurred $2.3 million through October 31, 2010. We are continuing to address the remaining remediation issues, including completing a groundwater monitoring plan and removing lead-based paint, both scheduled to be finished in our fiscal 2011.

Since 2009, we have identified USTs that may require remediation and have removed USTs that did not require additional remediation efforts. As of October 31, 2010, our undiscounted environmental liability for USTs for which we retain remediation responsibility is $.4 million.

As of October 31, 2010, our undiscounted environmental liability totaled $2.7 million, and consisted of $1.5 million for the four MGP sites for which we retain remediation responsibility, $.8 million for the LNG facility and $.4 million for USTs not yet remediated.

As of October 31, 2010, our regulatory assets for unamortized environmental costs totaled $8 million. We have not sought recovery of these amounts in our rates. However, we will seek recovery in future rate proceedings.

In July 2005, we were notified by the NCDENR that we were named as a potentially responsible party for alleged environmental issues associated with an UST site in Clemmons, North Carolina. We owned and operated 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 remediate the site is approximately $139,000. 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 $34,700, one-fourth of the estimated cost.

One of our operating districts has coatings containing asbestos on some of their pipelines. We have educated our employees on the hazards of asbestos and implemented procedures for removing these coatings from our pipelines when we must excavate and expose small portions of the pipeline. Lead-based paint is being removed at multiple LNG facilities that we own. Employees have been trained on the hazards of lead exposure, and we have engaged independent environmental contractors to remove and dispose of the lead-based paint at these facilities.

Further evaluation of the MGP sites, the UST sites and removal of lead-based paint 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, results of operations or cash flows.

8. Employee Benefit Plans

Effective January 1, 2008, we amended our noncontributory defined benefit pension plan, other postretirement employee benefits (OPEB) plan and our 401(k) plans. These amendments applied to nonunion employees and employees covered by the Carolinas bargaining unit contract. Effective January 1, 2009, these same amendments applied to all employees, including those covered by the Nashville, Tennessee bargaining unit contract.

Pension Benefits

We have a noncontributory, tax-qualified defined benefit pension plan (qualified pension plan) for our eligible employees. A defined benefit plan specifies the amount of benefit that an eligible participant eventually will receive upon retirement using information about that participant. An employee became eligible on the January 1 or July 1 following either the date on which he or she attained age 30 or attained age 21 and completed 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 or termination 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. Effective January 1, 2008, the qualified pension plan was amended for all employees not covered by the bargaining unit contract in Nashville, Tennessee to close the plan to employees hired after December 31, 2007 and to modify how benefits are accrued in the future for existing employees. Employees hired prior to January 1, 2008 continue to participate in the amended traditional qualified pension plan. Employees are vested after five years of service and can be credited with up to a total of 35 years of service. When a vested employee leaves the company, his benefit payment will be calculated as the greater of the accrued benefit as of December 31, 2007 under the old formula plus the accrued benefit under the new formula for years of service after December 31, 2007, or the benefit for all years of service up to 35 years under the new formula. These amendments were effective on January 1, 2009 for employees covered by the bargaining unit contract in Nashville, Tennessee.

The investment objectives of the qualified pension plan are oriented to meet both the current ongoing and future commitments to the participants and designed to grow at an acceptable rate of return for the risks permitted under the investment policy guidelines. Assets are structured to provide for both short-term and long-term needs and to meet the objectives of the qualified pension plan as overseen by the Benefits Committee of the Board of Directors.

Our primary investment objective of the qualified pension plan is to generate sufficient assets to meet plan liabilities. The plan's assets will therefore be invested to maximize long-term returns in a manner that is consistent with the plan's liabilities, cash flow requirements and risk tolerance. The plan's liabilities are defined in terms of participant salaries. Given the nature of these liabilities and recognizing the long-term benefits of investing in return-generating assets, the qualified pension plan seeks to invest in a diversified portfolio to:

- Achieve full funding over the longer term, and
- Control year-to-year fluctuations in pension expense that is created by asset and liability volatility.

We consider the historical long-term return experience of our assets, the current and targeted allocation of our plan assets and the expected long-term rates of return. Investment advisors assist us in deriving expected long-term rates of return. These rates are generally based on a 20-year horizon for various asset classes, our expected investments of plan assets and active asset management instead of a passive investment strategy of an index fund. In June 2009, the Benefits Committee of the Board of Directors approved a new asset allocation of our portfolio that includes additional asset classes, such as hedge fund of funds, private equity fund of funds, high yield bonds, global real estate and commodities. The intent of this new allocation was to provide further diversification and reduce volatility of plan assets.

The investment philosophy of the qualified pension plan is to maintain a balanced portfolio which is diversified across asset classes. The portfolio is primarily composed of equity and fixed income investments in order to provide diversification as to issuers, economic sectors, markets and investment instruments. Risk and quality are viewed in the context of the diversification requirements of the aggregate portfolio. We measure and monitor investment risk on an ongoing basis through quarterly investment portfolio reviews, annual liability measurements and periodic asset/liability studies. We do not have a concentration of assets in a single entity, industry, country, commodity or class of investment fund.

The qualified pension plan maintains a 45% target allocation to fixed income securities, including U.S. treasuries, corporate bonds, high yield bonds, asset-backed securities and derivatives. The derivatives must be fully collateralized so that they either hedge an existing position or there is a cash position for an equivalent value of the underlying principal. No leveraged position can be taken with derivatives, and the aggregate risk exposure of the plan can be no greater than that which could be achieved without using derivatives. The qualified pension plan maintains a 35% target allocation to equities, including exposure to large cap growth, large cap value and small cap domestic equity securities, as well as exposure to international equity. There is a 5% target allocation to real estate in a diversified global real estate investment trust (REIT) fund. The remaining 15% target allocation is for investments in other types of funds, including commodities, hedge funds and private equity funds that follow several diversified strategies.

Employees hired or rehired after December 31, 2007 (or December 31, 2008 for employees covered by the bargaining unit contract in Nashville, Tennessee) cannot participate in the amended traditional pension plan but are participants in the new Money Purchase Pension (MPP) plan, a defined contribution pension plan that allows the employee to direct the investments and assume the risk of investment returns. A defined contribution plan specifies the amount of the employer's annual contribution to individual participant accounts established for the retirement benefit. Eligible employees who have completed 30 days of continuous service and have attained age 18 are eligible to participate. Under the MPP plan, we annually deposit a percentage of each participant's pay into an account of the MPP plan. This contribution equals 4% of the participant's compensation plus an additional 4% of compensation above the social security wage base. The participant is vested in this plan after three years of service. During the year ended October 31, 2010, we contributed $.2 million to the MPP plan.

OPEB Plan

We provide certain postretirement health care and life insurance benefits to eligible retirees. 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. 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. Effective January 1, 2008 (January 1, 2009 for new employees covered under the bargaining unit contract in Nashville, Tennessee), new employees have to complete ten years of service after age 50 to be eligible for benefits, and no benefits are provided to those employees after age 65 when they are automatically eligible for Medicare benefits to cover health costs. Our OPEB plan includes a defined dollar benefit to pay the premiums for Medicare Part D. Employees who meet the eligibility requirements to retire also receive a life insurance benefit. For employees who retire after July 1, 2005, this benefit is $15,000. The life insurance amount for employees who retired prior to this date was calculated as a percentage of their basic life insurance prior to retirement.

OPEB plan assets are comprised of mutual funds within a 401(h) and Voluntary Employees' Beneficiary Association trusts. The investment philosophy is the same as the qualified pension plan as discussed above. We target an OPEB allocation of 45% to fixed income securities, including U.S. treasuries, corporate bonds, high yield bonds and asset-backed securities. The OPEB plan maintains a 47% target allocation to equities, which includes exposure to large cap growth, large cap value and small cap domestic equity, as well as exposure to international equity. The OPEB plan maintains a 5% target allocation to real estate in a diversified global REIT fund and a 3% target allocation to cash. We do not have a concentration of assets in a single entity, industry, country, commodity or class of investment fund.

Supplemental Executive Retirement Plans

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 previously had a SERP covering all officers at the vice president level and above. It provided supplemental retirement income as well as a life insurance benefit for officers to indirectly address the tax code limitations on qualified retirement plans. The level of insurance benefit and target retirement income benefits intended to be provided under the SERP depended upon the position of the officer. The SERP was funded by life insurance policies covering each officer, and the policy was owned exclusively by each officer.

On September 4, 2008, the Compensation Committee of our Board of Directors terminated the former SERP effective October 31, 2008 and replaced the supplemental retirement benefit with a non-qualified defined contribution restoration plan (DCR plan), effective January 1, 2009. Benefits payable under the new plan are informally funded through a rabbi trust with a bank as the trustee. We contribute 13% of the total cash compensation that exceeds the Internal Revenue Service compensation limit to the DCR plan account of each executive. An additional one-time contribution was made for all eligible officers in January 2009 equal to the greater of:

- 13% of base salary paid in November 2008 and December 2008 (to the extent that calendar year-to-date base salary exceeded the 2008 annual limit), or
- Two monthly premiums (without adjustment for taxes) under the former SERP.

In addition, an opening balance that totaled $.3 million was established for four Vice Presidents to compensate them for the loss of future benefits under the new plan. Participants may not contribute to the DCR plan. Vesting under the DCR plan is five-year cliff vesting, including service prior to adoption, of annual company contributions, and prospective five-year cliff vesting for the opening balances of the four Vice Presidents. If the officer severs employment before the expiration of the relevant five-year period, he or she receives nothing from that portion of the DCR plan. Participants in the DCR plan may provide instructions to us for the deemed investment of their plan accounts. Distribution will occur upon separation of service or death of the participant. The insurance portion of the SERP benefit has been maintained in the form of new term life insurance as discussed below.

Also on September 4, 2008, the Compensation Committee of our Board of Directors approved a voluntary deferred compensation plan, effective January 1, 2009, for the benefit of all officers and director-level employees. Benefits under this plan, known as the Voluntary Deferral Plan, are also informally funded through a rabbi trust with a bank as the trustee. There are no company contributions to the Voluntary Deferral Plan. Participants may defer up to 50% of base salary with elections made by December 31 prior to the upcoming calendar year, and up to 95% of annual incentive pay with elections made by April 30. Vesting is immediate and deferrals are held in the rabbi trust. Participants may provide instructions to us for the deemed investment of their plan accounts. Distributions can be made from the Voluntary Deferral Plan on a specified date that is at least two years from the date of deferral, on separation of service or upon death.

The funding to the DCR plan accounts for the years ended October 31, 2010 and 2009, and the amounts recorded as liabilities for these deferred compensation plans as of October 31, 2010 and 2009 are presented below.

In thousands	2010	2009
Funding	$ 444	$ 356
Liability:		
Current	5	-
Noncurrent	1,293	717

We provide term life insurance policies for officers at the vice president level and above who were participants in the former SERP that terminated on October 31, 2008; the level of the insurance benefit is dependent upon the position of the officer. These life insurance policies are owned exclusively by each officer. Premiums on these policies are paid and expensed, as grossed up for taxes to the individual officer. Beginning on December 1, 2008, we provide a term life insurance benefit equal to $200,000 to all officers and director-level employees for which we bear the cost of the policies. The cost of these premiums is presented below.

In thousands	2010	2009	2008
Vice president and above term life policies	$ 57	$ 59	$ -
SERP premiums (benefit superseded)	-	-	446
Officers, director-level employees and regional executives	24	20	-

Actuarial Plan Information

A reconciliation of changes in the plans' benefit obligations and fair value of assets for the years ended October 31, 2010 and 2009, and a statement of the funded status and the amounts reflected in the consolidated balance sheets for the years ended October 31, 2010 and 2009 are presented below.

In thousands	Qualified Pension 2010	Qualified Pension 2009	Nonqualified Pension 2010	Nonqualified Pension 2009	Other Benefits 2010	Other Benefits 2009
Accumulated benefit obligation at year end	$ 182,822	$ 173,352	$ 5,039	$ 4,828	N/A	N/A
Change in projected benefit obligation:						
Obligation at beginning of year	$ 195,329	$ 143,460	$ 4,828	$ 4,194	$ 35,523	$ 28,112
Service cost	8,069	5,733	38	25	1,337	885
Interest cost	10,898	11,240	243	325	1,906	2,267
Actuarial (gain) loss	7,549	45,669	420	920	(3,769)	7,506
Settlement gain	-	-	-	(126)	-	-
Administrative expenses	(306)	(233)	-	-	-	-
Benefit payments	(10,536)	(10,540)	(490)	(510)	(3,078)	(3,247)
Obligation at end of year	$ 211,003	$ 195,329	$ 5,039	$ 4,828	$ 31,919	$ 35,523
Change in fair value of plan assets:						
Fair value at beginning of year	$ 184,277	$ 150,257	$ -	$ -	$ 19,278	$ 15,522
Actual return on plan assets	32,910	22,793	-	-	2,841	2,146
Employer contributions	22,000	22,000	490	510	2,595	4,857
Administrative expenses	(306)	(233)	-	-	-	-
Benefit payments	(10,536)	(10,540)	(490)	(510)	(3,078)	(3,247)
Fair value at end of year	$ 228,345	$ 184,277	$ -	$ -	$ 21,636	$ 19,278
Noncurrent assets	$ 17,342	$ -	$ -	$ -	$ -	$ -
Current liabilities	-	-	(517)	(484)	-	-
Noncurrent liabilities	-	(11,052)	(4,522)	(4,344)	(10,283)	(16,245)
Net amount recognized	$ 17,342	$ (11,052)	$ (5,039)	$ (4,828)	$ (10,283)	$ (16,245)
Amounts Not Yet Recognized as a Component of Cost and Recognized as Regulatory Asset or Liability (1):						
Unrecognized transition obligation	$ -	$ -	$ -	$ -	$ (2,001)	$ (2,668)
Unrecognized prior service (cost) credit	23,836	26,033	(88)	(107)	-	-
Unrecognized actuarial loss	(85,661)	(94,247)	(852)	(442)	(9)	(5,474)
Regulatory asset	(61,825)	(68,214)	(940)	(549)	(2,010)	(8,142)
Cumulative employer contribution in excess of cost	79,167	57,162	(4,099)	(4,279)	(8,273)	(8,103)
Net amount recognized	$ 17,342	$ (11,052)	$ (5,039)	$ (4,828)	$ (10,283)	$ (16,245)

(1) 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 OCI as a regulatory asset or liability.

Net periodic benefit cost for the years ended October 31, 2010, 2009 and 2008 includes the following components.

In thousands	Qualified Pension 2010	Qualified Pension 2009	Qualified Pension 2008	Nonqualified Pension 2010	Nonqualified Pension 2009	Nonqualified Pension 2008	Other Benefits 2010	Other Benefits 2009	Other Benefits 2008
Service cost	$ 8,069	$ 5,733	$ 7,634	$ 38	$ 25	$ 27	$ 1,337	$ 885	$ 1,250
Interest cost	10,898	11,240	11,408	243	325	277	1,906	2,267	2,011
Expected return on plan assets	(18,773)	(16,755)	(16,895)	-	-	-	(1,381)	(1,104)	(1,461)
Amortization of transition obligation	-	-	-	-	-	-	667	667	667
Amortization of prior service (cost) credit	(2,198)	(2,198)	(1,893)	20	20	-	-	-	-
Amortization of actuarial loss (gain)	1,998	-	-	9	(20)	-	236	-	-
Net periodic benefit (income) cost	(6)	(1,980)	254	310	350	304	2,765	2,715	2,467
Other changes in plan assets and benefit obligation recognized through regulatory asset or liability:									
Prior service cost (credit)	-	-	(4,133)	-	-	127	-	-	-
Net (gain) loss	(6,587)	39,631	42,446	420	923	(532)	(5,229)	6,464	1,237
Amounts recognized as a component of net periodic benefit cost:									
Transition obligation	-	-	-	-	-	-	(667)	(667)	(667)
Amortization of net (loss) gain	(1,998)	-	-	(9)	20	-	(236)	-	-
Prior service (cost) credit	2,198	2,198	1,893	(20)	(20)	-	-	-	-
Total recognized in regulatory asset (liability)	(6,387)	41,829	40,206	391	923	(405)	(6,132)	5,797	570
Total recognized in net periodic benefit cost and regulatory asset (liability)	$ (6,393)	$ 39,849	$ 40,460	$ 701	$ 1,273	$ (101)	$ (3,367)	$ 8,512	$ 3,037

The 2011 estimated amortization of the following items is recorded as a regulatory asset or liability instead of accumulated OCI discussed above and expected refunds for our plans are as follows.

In thousands	Qualified Pension	Nonqualified Pension	Other Benefits
Amortization of transition obligation	$ -	$ -	$ 667
Amortization of unrecognized prior service (cost) credit	(2,198)	20	-
Amortization of unrecognized actuarial loss	3,113	41	-
Refunds expected	915	61	667

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 Investors Service's AA or better-rated non-callable bonds that produces similar results to a hypothetical bond portfolio. As of October 31, 2010, the benchmark by plan was as follows.

Pension plan	5.47%
NCNG SERP	4.33%
Directors' SERP	4.61%
Piedmont SERP	3.49%
OPEB	4.85%

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.

The weighted average assumptions used in the measurement of the benefit obligation as of October 31, 2010 and 2009 are presented below.

	Qualified Pension		Nonqualified Pension		Other Benefits	
	2010	2009	2010	2009	2010	2009
Discount rate	5.47%	5.99%	4.37%	5.28%	4.85%	5.58%
Rate of compensation increase	3.87%	3.92%	N/A	N/A	N/A	N/A

The weighted average assumptions used to determine the net periodic benefit cost as of October 31, 2010, 2009 and 2008 are presented below.

	Qualified Pension			Nonqualified Pension		
	2010	2009	2008	2010	2009	2008
Discount rate	5.99%	8.15%	6.43%	5.28%	8.46%	6.06%
Expected long-term rate of return on plan assets	8.00%	8.00%	8.00%	N/A	N/A	N/A
Rate of compensation increase	3.92%	3.97%	3.99%	N/A	N/A	N/A

	Other Benefits		
	2010	2009	2008
Discount rate	5.58%	8.50%	6.25%
Expected long-term rate of return on plan assets	8.00%	8.00%	8.00%
Rate of compensation increase	N/A	N/A	N/A

In November 2010, we contributed $22 million to the qualified pension plan. We anticipate that we will contribute the following amounts to our plans in 2011.

In thousands	
Nonqualified pension plans	$ 517
MPP plan	345
OPEB plan	1,400

The Pension Protection Act of 2006 (PPA) specified new funding requirements for single employer defined benefit pension plans. The PPA established a 100% funding target for plan years beginning after December 31, 2007, and we are in compliance.

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

In thousands	Qualified Pension	Nonqualified Pension	Other Benefits
2011	$ 19,122	$ 517	$ 2,193
2012	12,122	489	2,185
2013	13,289	486	2,210
2014	12,550	454	2,422
2015	13,613	453	2,524
2016 - 2020	82,692	1,934	13,978

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, 2010 and 2009 are presented below.

	2010	2009
Health care cost trend rate assumed for next year	7.80%	8.00%
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	2027	2027

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.

In thousands	1% Increase	1% Decrease
Effect on total of service and interest cost components of net periodic postretirement health care benefit cost for the year ended October 31, 2010	$ 57	$ (55)
Effect on the health care cost component of the accumulated postretirement benefit obligation as of October 31, 2010	732	(723)

Fair Value Measurements

The qualified pension plan's asset allocations by level within the fair value hierarchy at October 31, 2010 are presented below. The plan's assets were accounted for at fair value and are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and their placement within the fair value hierarchy levels. For further information on a description of the fair value hierarchy, see Note 1.F. to the consolidated financial statements.

	Qualified Pension Plan				
In thousands	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value	% of Total
Cash	$ 1,969	$ -	$ -	$ 1,969	1%
Fixed Income Securities:					50%
U.S. treasuries	-	26,886	-	26,886	12%
Long duration bonds (1)	60,393	-	-	60,393	26%
Corporate bonds	-	13,063	-	13,063	6%
High yield bonds (2)	11,509	-	-	11,509	5%
Derivatives	(27)	1,694	-	1,667	1%
Equity Securities: (3)					39%
Large cap core index (4)	10,815	-	-	10,815	5%
Large cap value	10,640	-	-	10,640	5%
Large cap growth	12,601	-	-	12,601	5%
Small cap	21,748	-	-	21,748	9%
International value	17,170	-	-	17,170	7%
International growth	17,243	-	-	17,243	8%
Real Estate:					5%
Global REIT	12,070	-	-	12,070	5%
Other Investments:					5%
Hedge fund of funds (5)	-	4,795	5,196	9,991	5%
Private equity fund of funds (6)	-	-	580	580	-%
Total assets at fair value	$ 176,131	$ 46,438	$ 5,776	$ 228,345	100%
Percent of fair value hierarchy	77%	20%	3%	100%	

(1) This category represents actively managed long duration fixed income funds.
(2) This category represents actively managed high yield fixed income funds.
(3) This category represents actively managed equity funds and separate accounts with diversified investment strategies with the exception of the Large Cap Core Index Fund category.
(4) This category represents low-cost equity index funds not actively managed that track the S&P 500 Index.
(5) This category represents investments across a variety of markets through investment funds or managed accounts that invest in equities, equity-related instruments, fixed income and other debt-related instruments.
(6) This category represents exposure to a diversified private equity fund of funds investment. The target allocation is 5% but is still being funded through capital calls. Until a 5% allocation can be achieved, the balance of the 5% allocation is invested in a low-cost equity fund managed to track the S&P 500 index.

The following is a reconciliation of the assets in the qualified pension plan that are classified as Level 3 in the fair value hierarchy.

In thousands	Hedge Fund of Funds	Private Equity Fund of Funds	Total
Beginning balance at October 31, 2009	$ -	$ -	$ -
Actual return on plan assets:			
Relating to assets still held at the reporting date	307	(4)	303
Relating to assets sold during the period	-	-	-
Purchases, sales and settlements (net)	4,889	584	5,473
Transfer in/out of Level 3	-	-	-
Ending balance at October 31, 2010	$ 5,196	$ 580	$ 5,776

The OPEB plan's asset allocations by level within the fair value hierarchy at October 31, 2010 are presented below. The plan's assets were accounted for at fair value and are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and their placement within the fair value hierarchy levels. For further information on a description of the fair value hierarchy, see Note 1.F. to the consolidated financial statements.

In thousands	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value	% of Total
	Other Benefits (1)				
Cash	$ 526	$ -	$ -	$ 526	3%
Fixed Income Securities:					45%
U.S. treasuries	2,164	-	-	2,164	10%
Corporate bonds (2) / Asset-backed securities	7,603	-	-	7,603	35%
Equity Securities:					47%
Large cap value	1,131	-	-	1,131	5%
Large cap growth	1,152	-	-	1,152	5%
Small cap value	1,158	-	-	1,158	5%
Small cap growth	1,162	-	-	1,162	5%
Large cap index	2,019	-	-	2,019	10%
International blend	3,650	-	-	3,650	17%
Real Estate:					5%
Global REIT	1,071	-	-	1,071	5%
Total assets at fair value	$ 21,636	$ -	$ -	$ 21,636	100%
Percent of fair value hierarchy	100%	-	-	100%	

(1) The plan assets are invested in mutual funds.
(2) This category represents primarily investment grade corporate securities even though the plan maintains a 5% allocation to a high yield bond fund.

401(k) Plan

We maintain a 401(k) plan that is a profit-sharing plan under Section 401(a) of the Internal Revenue Code of 1986, as amended (the Tax Code), which includes qualified cash or deferred arrangements under Tax Code Section 401(k). The 401(k) plan is subject to the provisions of the Employee Retirement Income Security Act. Eligible 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 and cash incentive payments to the plan, and we match a portion of their contributions. Employee contributions vest immediately, and company contributions vest after six months of service.

Effective January 1, 2008, we made changes to our 401(k) plan. Prior to January 1, 2008, we matched 50% of employee contributions up to the first 10% of pay contributed. Beginning January 1, 2008 (January 1, 2009 for employees covered under the bargaining unit contract in Nashville, Tennessee), employees receive a company match of 100% up to the first 5% of eligible pay contributed. Employees may contribute up to 50% of eligible pay to the 401(k) on a pre-tax basis, up to the Tax Code annual contribution limit. We automatically enroll all affected non-participating employees in the 401(k) plan at a 2% contribution rate unless the employee chooses not to participate by notifying our record keeper. For employees who are automatically enrolled in the 401(k) plan, we automatically increase their contributions by 1% each year to a maximum of 5% unless the employee chooses to opt out of the automatic increase by contacting our record keeper. If the employee does not make an investment election, employee contributions and matches are automatically invested in a diversified portfolio of stocks and bonds. Participants may invest in Piedmont stock up to a maximum of 20% of their account. Employees may change their contribution rate and investments at any time. For the years ended October 31, 2010, 2009 and 2008, we made matching contributions to participant accounts as follows.

In thousands	2010	2009	2008
401(k) matching contributions	$ 5,269	$ 4,698	$ 4,252

As a result of a plan merger effective in 2001, participants' accounts in our employee stock ownership plan (ESOP) were transferred into our 401(k) plans. Former ESOP participants may remain invested in Piedmont common stock in their 401(k) 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 statements of stockholders' equity as an increase in retained earnings.

9. Employee Share-Based Plans

Under Board of Directors approved incentive compensation plans, eligible officers and other participants are awarded units that pay out depending upon the level of performance achieved by Piedmont during three-year performance periods. Distribution of those awards may be made in the form of shares of common stock and withholdings for payment of applicable taxes on the compensation. These plans require that a minimum threshold performance level be achieved in order for any award to be distributed. For the years ended October 31, 2010, 2009 and 2008, we recorded compensation expense, and as of October 31, 2010 and 2009, we have accrued amounts for these awards 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.

We have three awards under approved incentive compensation plans with three-year performance periods ending October 31, 2010, October 31, 2011 and October 31, 2012. Fifty percent of the units awarded will be based on achievement of a target annual compounded increase in basic 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 total annual shareholder return (increase in our common stock price plus dividends reinvested over the specified period of time) in comparison to a peer group consisting of natural gas distribution companies. The total shareholder return performance measure will be our 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.

Also under our approved incentive compensation plan, 65,000 unvested shares of our common stock were granted to our President and Chief Executive Officer in September 2006. During the five-year vesting period, any dividends paid on these shares are accrued and converted into additional shares at the closing price on the date of the dividend payment. In accordance with the vesting schedule, 20% and 30% of the shares vested on September 1, 2009 and 2010, respectively. The remaining 50% of the shares will vest on September 1, 2011.

The compensation expense related to the incentive compensation plans for the years ended October 31, 2010, 2009 and 2008, and the amounts recorded as liabilities as of October 31, 2010 and 2009 are presented below.

In thousands	2010	2009	2008
Compensation expense	$ 6,118	$ 2,487	$ 7,027
Tax benefit	1,756	207	1,555
Liability	9,914	8,173	

Based on current accrual assumptions, the expected payout for the approved incentive compensation plans ending October 31, 2010, 2011 and 2012 will occur in the following fiscal years.

In thousands	2011	2012	2013
Amount of payout	$ 7,094	$ 1,594	$ 1,227

On a quarterly basis, we issue shares of common stock under the ESPP and have accounted for the issuance as an equity transaction. The exercise 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 to the consolidated financial statements, we repurchase shares on the open market and such shares are then cancelled and become authorized but unissued shares. Currently, it is our policy to issue new shares for share-based awards. Shares of common stock to be issued under approved incentive compensation plans are contingently issuable shares and are included in our calculation of fully diluted earnings per share.

10. Income Taxes

The components of income tax expense for the years ended October 31, 2010, 2009 and 2008 are presented below.

In thousands	2010 Federal	2010 State	2009 Federal	2009 State	2008 Federal	2008 State
Charged (Credited) to operating income:						
Current	$ 18,133	$ 3,928	$ (7,774)	$ 181	$ 27,971	$ 6,679
Deferred	33,432	6,866	65,828	12,047	24,285	4,237
Tax Credits:						
Utilization	105	-	130	-	-	-
Amortization	(382)	-	(333)	-	(358)	-
Total	51,288	10,794	57,851	12,228	51,898	10,916
Charged (Credited) to other income (expense):						
Current	22,519	3,755	7,764	1,064	10,040	1,786
Deferred	2,963	557	2,492	483	(1,025)	(123)
Total	25,482	4,312	10,256	1,547	9,015	1,663
Total	$ 76,770	$ 15,106	$ 68,107	$ 13,775	$ 60,913	$ 12,579

A reconciliation of income tax expense at the federal statutory rate to recorded income tax expense for the years ended October 31, 2010, 2009 and 2008 is presented below.

In thousands	2010	2009	2008
Federal taxes at 35%	$ 81,841	$ 71,647	$ 64,225
State income taxes, net of federal benefit	9,819	8,954	8,176
Amortization of investment tax credits	(382)	(333)	(358)
Other, net	598	1,614	1,449
Total	$ 91,876	$ 81,882	$ 73,492

As of October 31, 2010 and 2009, deferred income taxes consisted of the following temporary differences.

In thousands	2010	2009
Deferred tax assets:		
Benefit of loss carryforwards	$ 2,474	$ 17,995
Employee benefits and compensation	13,082	17,233
Revenue requirement	10,530	7,647
Utility plant	9,183	9,197
Other	4,958	7,881
Total deferred tax assets	40,227	59,953
Valuation Allowance	(1,324)	(1,400)
Total deferred tax assets, net	38,903	58,553
Deferred tax liabilities:		
Utility plant	370,348	334,878
Revenues and cost of gas	14,976	40,043
Equity method investments	27,244	22,597
Deferred costs	46,387	49,279
Other	14,106	3,456
Total deferred tax liabilities	473,061	450,253
Net deferred income tax liabilities	$ 434,158	$ 391,700

As of October 31, 2010 and 2009, total net deferred income tax assets were net of a valuation allowance to reduce amounts to the amounts that we believe will be more likely than not realized. We and our wholly owned subsidiaries file a consolidated federal income tax return and various state income tax returns. As of October 31, 2010 and 2009, we had federal net operating loss carryforwards of $6.5 million and $45.6 million, respectively, which expire from 2023 through 2029. As of October 31, 2010 and 2009, we had state net operating loss carryforwards of $7.1 million and $58.2 million, respectively, which expire from 2018 through 2024. We may use the loss carryforwards to offset taxable income. Of the loss carryforwards, $6.5 million are subject to an annual limitation of $.3 million.

Our returns for the tax years ended October 31, 2006 through 2007 are currently under examination by the Internal Revenue Service. We do not expect the audit to have a material effect on our financial position, results of operations or cash flows. We are no longer subject to federal income tax examinations for tax years ending before and including October 31, 2005, and with few exceptions, state income tax examinations by tax authorities for years ended before and including October 31, 2005.

A reconciliation of changes in the deferred tax valuation allowance for the years ended October 31, 2010, 2009 and 2008 is presented below.

In thousands	2010	2009	2008
Balance at beginning of year	$ 1,400	$ 1,114	$ 394
Charged (credited) to income tax expense	(76)	286	720
Balance at end of year	$ 1,324	$ 1,400	$ 1,114

A reconciliation of the unrecognized tax benefits for the years ended October 31, 2010 and 2009 is presented below.

In thousands	2010	2009
Balance, beginning of year	$ 293	$ 506
Decrease from settlements with taxing authorities	-	125
Decrease from expiration of statute of limitations	293	88
Balance, end of year	$ -	$ 293

The amount of unrecognized tax benefits at 2009 which would impact our effective income tax rate, if recognized, was $.2 million.

We recognize accrued interest and penalties related to unrecognized tax benefits in operating expenses in the consolidated statements of income, which is consistent with the recognition of these items in prior reporting periods. We recorded immaterial amounts of interest related to unrecognized tax benefits during the years ended October 31, 2010 and 2009.

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. 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, 2010, 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. (Cardinal), a North Carolina limited liability company. The other members are subsidiaries of The Williams Companies, Inc. and SCANA 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 nonrecourse to the members and is secured by Cardinal's assets and by each member's equity investment in Cardinal.

On October 22, 2009, we reached an agreement with Progress Energy Carolinas, Inc. to provide natural gas delivery service to a power generation facility to be built at their Wayne County, North Carolina site. To provide the additional delivery service, we have executed an agreement with Cardinal, which was approved by the NCUC in May 2010, to expand our firm capacity requirement by 149,000 dekatherms per day to serve Progress Energy Carolinas. This will require Cardinal to spend as much as $53.1 million for a new compressor station and expanded meter stations in order to increase the capacity of its system by up to 199,000 dekatherms per day of firm capacity. As an equity venture partner of Cardinal, we will invest as much as $11.4 million in Cardinal's system expansion. The members' capital will be replaced with permanent financing with a target overall capital structure of 45-50% debt and 50-55% equity after the project is placed into service, scheduled to be July 1, 2012. In addition, Piedmont's service subscription to Cardinal following the system expansion will increase from approximately 37% to approximately 53%. The NCUC issued a formal certificate order for Progress Energy Carolinas for their Wayne County generation project on October 1, 2009.

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, 2010, 2009 and 2008, these transportation costs and the amounts we owed Cardinal as of October 31, 2010 and 2009 are as follows.

In thousands	2010	2009	2008
Transportation costs	$ 4,104	$ 4,104	$ 4,116
Trade accounts payable	349	349	

Summarized financial information provided to us by Cardinal for 100% of Cardinal as of September 30, 2010 and 2009, and for the twelve months ended September 30, 2010, 2009 and 2008 is presented below.

In thousands	2010	2009	2008
Current assets	$ 9,239	$ 9,078	
Non-current assets	75,508	78,089	
Current liabilities	3,977	3,990	
Non-current liabilities	26,592	29,075	
Revenues	13,633	13,633	$ 13,670
Gross profit	13,633	13,633	13,670
Income before income taxes	6,375	6,893	7,050

Pine Needle LNG Company, L.L.C.

We own 40% of the membership interests in Pine Needle LNG Company, L.L.C., (Pine Needle), 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 an interstate LNG 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 loss" in the consolidated balance sheets. Pine Needle's long-term debt is nonrecourse to the members and 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, 2010, 2009 and 2008, these gas storage costs and the amounts we owed Pine Needle as of October 31, 2010 and 2009 are as follows.

In thousands	2010	2009	2008
Gas storage costs	$ 12,158	$ 12,364	$ 11,516
Trade accounts payable	985	1,081	

Summarized financial information provided to us by Pine Needle for 100% of Pine Needle as of September 30, 2010 and 2009, and for the twelve months ended September 30, 2010, 2009 and 2008 is presented below.

In thousands	2010	2009	2008
Current assets	$ 15,593	$ 10,618	
Non-current assets	78,863	78,452	
Current liabilities	3,923	8,485	
Non-current liabilities	35,007	20,526	
Revenues	18,808	18,744	$ 18,694
Gross profit	18,808	18,744	18,694
Income before income taxes	8,317	8,381	8,227

SouthStar Energy Services LLC

We own 15% of the membership interests in SouthStar Energy Services LLC (SouthStar), a Delaware limited liability company. The other member is Georgia Natural Gas Company (GNGC), a wholly-owned subsidiary of AGL Resources, Inc. SouthStar primarily sells natural gas to residential, commercial and industrial customers in the southeastern United States and Ohio with most of its business being conducted in the unregulated retail gas market in Georgia. On January 1, 2010, we sold half of our 30% membership interest in SouthStar to GNGC and retained a 15% earnings and membership share in SouthStar after the sale. At closing, we received $57.5 million from GNGC resulting in an after-tax gain of $30.3 million, or $.42 per diluted share for 2010. GNGC has no further rights to acquire our remaining 15% interest. We will continue to account for our 15% membership interest in SouthStar using the equity method, as we retain board representation with voting rights equal to GNGC on significant governance matters and policy decisions, and thus, exercise significant influence over the operations of SouthStar.

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 and natural gas consumption is higher. 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 and weather changes on the timing of its earnings, wholesale price and weather 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 loss" 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, 2010, 2009 and 2008, our operating revenues from these sales and the amounts SouthStar owed us as of October 31, 2010 and 2009 are as follows.

In thousands	2010	2009	2008
Operating revenues	$ 5,083	$ 8,226	$ 14,624
Trade accounts receivable	713	639	

Summarized financial information provided to us by SouthStar for 100% of SouthStar as of September 30, 2010 and 2009, and for the twelve months ended September 30, 2010, 2009 and 2008 is presented below.

In thousands	2010	2009	2008
Current assets	$ 167,218	$ 148,402	
Non-current assets	9,382	9,454	
Current liabilities	62,899	50,010	
Non-current liabilities	160	-	
Revenues	843,483	854,455	$ 941,123
Gross profit	183,748	169,639	143,534
Income before income taxes	107,096	98,308	73,224

Hardy Storage Company, LLC

Piedmont Hardy Storage Company, LLC, 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. Hardy Storage has firm service contracts with customers for 100% of its storage capacity of the facility, of which Piedmont subscribes to approximately 40%.

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. 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.

The members of Hardy Storage each guaranteed 50% of the construction financing as well as a separate guaranty of 50% of construction expenditures should contingency wells be required based on the performance of the facility over the first three years after the in-service date. The Guaranty of Principal and Residual Guaranty were executed by a wholly owned subsidiary of Piedmont, Piedmont Energy Partners, Inc. (PEP). Our share of the guaranty was capped at $111.5 million and expired upon the closing of permanent financing. Securing our guaranty was a pledge of intercompany notes issued by Piedmont to its non-utility subsidiaries held under its wholly owned subsidiary. Also pledged was our membership interest in Hardy Storage.

On March 17, 2010, Hardy Storage paid $3.6 million on the interim notes to enable completion of its conversion of the interim notes to long-term project financing. The new long-term notes are for $119.8 million due in 2023 at 5.88%. As a result of the conversion, our Guaranty of Principal and Residual Guaranty, as executed in connection with the interim financing, terminated with no payments having been made. The long-term project financing is non-recourse to the members of Hardy Storage and their parent entities.

Prior to the long-term financing, we had recorded a liability of $1.2 million for the fair value of the guaranty based on the present value of 50% of the construction financing outstanding at the end of each quarter with the risk of the project evaluated at each quarter end, with a corresponding increase to our investment account in the venture. Upon completion of the permanent financing in March 2010, the liability was reversed, and our investment account was adjusted accordingly to reflect the elimination of the guaranty.

The detail of the guaranty as of October 31, 2009 is as follows.

<u>In thousands</u>

Guaranty liability- PEP	$	1,234
Amount outstanding under the construction financing - Hardy Storage		123,410

During 2010, we made no equity contributions to Hardy Storage and received distributions totaling $12.9 million. As of October 31, 2010, we have made net equity contributions for the project totaling $11.8 million.

We have related party transactions as a customer of Hardy Storage and record in cost of gas the storage costs charged by Hardy Storage. For the years ended October 31, 2010, 2009 and 2008, these gas storage costs and the amounts we owed Hardy Storage as of October 31, 2010 and 2009 are as follows.

In thousands	2010	2009	2008
Gas storage costs	$ 9,386	$ 9,340	$ 9,219
Trade accounts payable	808	781	

Summarized financial information provided to us by Hardy Storage for 100% of Hardy Storage as of October 31, 2010 and 2009, and for the twelve months ended October 31, 2010, 2009 and 2008 is presented below.

In thousands	2010	2009	2008
Current assets	$ 13,070	$ 37,136	
Non-current assets	170,693	166,663	
Current liabilities	15,280	127,288	
Non-current liabilities	109,495	-	
Revenues	23,562	23,465	$ 23,658
Gross profit	23,562	23,465	23,658
Income before income taxes	8,249	8,155	9,297

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. 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" and "Non-operating income."

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, 2010, 2009 and 2008, and as of October 31, 2010 and 2009 are presented below.

In thousands	Regulated Utility	Non-Utility Activities	Total
2010			
Revenues from external customers	$ 1,552,295	$ -	$ 1,552,295
Margin	552,592	-	552,592
Operations and maintenance expenses	219,829	301	220,130
Depreciation	98,494	29	98,523
Income from equity method investments	-	28,854	28,854
Gain on sale of interest in equity method investment	-	49,674	49,674
Interest expense	43,711	-	43,711
Operating income (loss) before income taxes	200,360	(697)	199,663
Income before income taxes	155,923	77,907	233,830
Total assets	2,784,087	80,808	2,864,895
Equity method investments in non-utility activities	-	80,287	80,287
Construction expenditures	199,059	-	199,059

In thousands	Regulated Utility	Non-Utility Activities	Total
2009			
Revenues from external customers	$ 1,638,116	$ -	$ 1,638,116
Margin	561,574	-	561,574
Operations and maintenance expenses	208,105	326	208,431
Depreciation	97,425	29	97,454
Income from equity method investments	-	33,464	33,464
Interest expense	46,675	34	46,709
Operating income (loss) before income taxes	221,454	(503)	220,951
Income before income taxes	171,752	32,954	204,706
Total assets	2,919,260	104,891	3,024,151
Equity method investments in non-utility activities	-	104,429	104,429
Construction expenditures	129,006	-	129,006

In thousands	Regulated Utility	Non-Utility Activities	Total
2008			
Revenues from external customers	$ 2,089,108	$ -	$ 2,089,108
Margin	552,973	-	552,973
Operations and maintenance expenses	210,757	160	210,917
Depreciation	93,121	29	93,150
Income from equity method investments	-	27,718	27,718
Interest expense	59,273	79	59,352
Operating income (loss) before income taxes	215,925	(277)	215,648
Income before income taxes	156,400	27,099	183,499
Construction expenditures	181,012	-	181,012

Reconciliations to the consolidated financial statements for the years ended October 31, 2010, 2009 and 2008, and as of October 31, 2010 and 2009 are as follows.

In thousands	2010	2009	2008
Operating Income:			
Segment operating income before income taxes	$ 199,663	$ 220,951	$ 215,648
Utility income taxes	(62,082)	(70,079)	(62,814)
Non-utility activities before income taxes	697	503	277
Total	$ 138,278	$ 151,375	$ 153,111
Net Income:			
Income before income taxes for reportable segments	$ 233,830	$ 204,706	$ 183,499
Income taxes	(91,876)	(81,882)	(73,492)
Total	$ 141,954	$ 122,824	$ 110,007
Consolidated Assets:			
Total assets for reportable segments	$ 2,864,895	$ 3,024,151	
Eliminations/Adjustments	188,380	94,668	
Total	$ 3,053,275	$ 3,118,819	

13. Subsequent Events

We monitor significant events occurring after the balance sheet date and prior to the issuance of the financial statements to determine the impacts, if any, of events on the financial statements to be issued. All subsequent events of which we are aware were evaluated. For information on subsequent event disclosure related to regulatory matters, see Note 2 to the consolidated financial statements.

14. 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 2010						
January 31	$ 673,736	$ 222,942	$ 87,801	$ 113,749	$ 1.55	$ 1.55
April 30	472,846	168,678	52,225	46,825	0.65	0.65
July 31	211,603	77,897	(3,471)	(9,518)	(0.13)	(0.13)
October 31	194,110	83,075	1,723	(9,102)	(0.13)	(0.13)
Fiscal Year 2009						
January 31	$ 779,644	$ 220,683	$ 88,131	$ 80,876	$ 1.10	$ 1.10
April 30	455,432	169,953	55,351	53,525	0.73	0.73
July 31	180,201	80,839	1,585	(7,300)	(0.10)	(0.10)
October 31	222,839	90,099	6,308	(4,277)	(0.06)	(0.06)

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

Our 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 as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act as of the end of the period covered by this Form 10-K. Such disclosure controls and procedures are designed to provide reasonable assurance that the information we are required to disclose in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods required by the United States Securities and Exchange Commission'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 such evaluation, the President and Chief Executive Officer and the Senior Vice President and Chief Financial Officer concluded that, as of the end of the period covered by this Form 10-K, our disclosure controls and procedures were effective at the reasonable assurance level.

We routinely review our internal control over financial reporting and from time to time make changes intended to enhance the effectiveness of our internal control over financial reporting. There were no changes to our internal control over financial reporting as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act during the fourth quarter of fiscal 2010 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

December 23, 2010

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 Ethics and Business Conduct 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. Based upon such evaluation, our management concluded that as of October 31, 2010, our internal control over financial reporting was effective.

The Company's independent registered public accounting firm, Deloitte & Touche LLP, has issued its report on the effectiveness of the Company's internal control over financial reporting as of October 31, 2010.

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the internal control over financial reporting of Piedmont Natural Gas Company, Inc. and subsidiaries (the "Company") as of October 31, 2010, 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 assertion 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 opinion.

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 and corrected 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, 2010, 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 as of and for the year ended October 31, 2010 of the Company and our report dated December 23, 2010 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Charlotte, North Carolina
December 23, 2010

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 "Information Regarding the Board of Directors" and "Executive Officers" in our Proxy Statement for the 2011 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 2011 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 2011 Annual Meeting of Shareholders, which section is incorporated in this annual report on Form 10-K by reference.

We have adopted a Code of Ethics and Business Conduct that is applicable to all our directors, officers and employees, including our principal executive officer, principal financial officer and principal accounting officer. We have also adopted Special Provisions Relating to the Company's Principal Executive Officer and Senior Financial Officers (Special Provisions) that are part of our Corporate Governance Guidelines and that apply to our principal executive officer, principal financial officer and principal accounting officer. The Code of Ethics and Business Conduct and Special Provisions are available on the "For Investors-Corporate Governance" section of our website at www.piedmontng.com. If we amend or grant a waiver, including an implicit waiver, from the Code of Ethics and Business Conduct or Special Provisions 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 "For Investors-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 2011 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 2011 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 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 2011 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 2011 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 2 – Ratification of the Appointment of Deloitte & Touche LLP As Independent Registered Public Accounting Firm For the 2011 Fiscal Year" in our Proxy Statement for the 2011 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, 2010, are included in Item 8 of this report as follows:

Consolidated Balance Sheets - October 31, 2010 and 2009
Consolidated Statements of Income - Years Ended
October 31, 2010, 2009 and 2008
Consolidated Statements of Cash Flows - Years Ended
October 31, 2010, 2009 and 2008
Consolidated Statements of Stockholders' Equity – Years Ended
October 31, 2010, 2009 and 2008
Notes to Consolidated Financial Statements

(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 10.22 are management contracts or compensatory plans or arrangements.

3.1 Restated Articles of Incorporation of Piedmont Natural Gas Company, Inc., dated as of March 2009 (Exhibit 3.1, Form 10-Q for the quarter ended July 31, 2009).

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 (Exhibit 3.3, Form 10-K for the fiscal year ended October 31, 2007).
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 (Exhibit 4.2, Form 10-K for the fiscal year ended October 31, 2007).
4.3	Indenture, dated as of April 1, 1993, between Piedmont and The Bank of New York Mellon Trust Company, N.A. (as successor to Citibank, N.A.), Trustee (Exhibit 4.1, Form S-3 Registration Statement No. 33-59369).
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	Form of Master Global Note, executed September 9, 1999 (Exhibit 4.4, Form S-3 Registration Statement No. 333-26161).
4.11	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).

4.12 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).

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

4.14 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).

4.15 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).

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

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

4.18 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).

4.19 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).

4.20 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 Establishment of Measures for Long-Term Incentive Plan 10 (filed in Form 8-K dated October 20, 2006, as Item 1.01).

10.3 Employment Agreement with David J. Dzuricky, dated December 1, 1999 (Exhibit 10.37, Form 10-K for the fiscal year ended October 31, 1999).

10.4 Employment Agreement with Thomas E. Skains, dated December 1, 1999 (Exhibit 10.40, Form 10-K for the fiscal year ended October 31, 1999).

10.5 Employment Agreement with Franklin H. Yoho, dated March 18, 2002 (Exhibit 10.23, Form 10-K for the fiscal year ended October 31, 2002).

10.6 Employment Agreement with Michael H. Yount, dated May 1, 2006 (Exhibit 10.1, Form 10-Q for the quarter ended April 30, 2006).

10.7 Employment Agreement with Kevin M. O'Hara, dated May 1, 2006 (Exhibit 10.2, Form 10-Q for the quarter ended April 30, 2006).

10.8 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).

10.9 Schedule of Severance Agreements with Executives (Exhibit 10.2a, Form 10-Q for the quarter ended July 31, 2007).

10.10 Piedmont Natural Gas Company, Inc. Incentive Compensation Plan (Exhibit 10.1, Form 8-K dated March 3, 2006).

10.11 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).

10.12 Form of Performance Unit Award Agreement (Exhibit 10.1, Form 10-Q for the quarter ended January 31, 2010).

10.13 Resolution of Board of Directors, February 26, 2010, establishing compensation for non-management directors (Exhibit 10.1, Form 10-Q for the quarter ended April 30, 2010).

10.14 Incentive Compensation Plan Interpretive Guidelines as of September 7, 2007 (Exhibit 10.24, Form 10-K for the fiscal year ended October 31, 2007).

10.15 Piedmont Natural Gas Company, Inc. Voluntary Deferral Plan, dated as of December 8, 2008, effective November 1, 2008 (Exhibit 10.1, Form 10-Q for quarter ended January 31, 2009).

10.16 Piedmont Natural Gas Company, Inc. Defined Contribution Restoration Plan, dated as of December 8, 2008, effective January 1, 2009 (Exhibit 10.2, Form 10-Q for quarter ended January 31, 2009).

10.17 Piedmont Natural Gas Company Employee Stock Purchase Plan, amended and restated as of April 1, 2009 (Exhibit 4.1, Form 8-K dated April 13, 2009).

10.18 Amendment No. 1 to Director Retirement Benefits Agreements with outside directors, dated as of December 31, 2008 (Exhibit 10.1, Form 10-Q for quarter ended July 31, 2009).

10.19 Instrument of Amendment for Piedmont Natural Gas Company, Inc. 401(k) Plan dated as of December 17, 2009 (Exhibit 10.2, Form 10-Q for the quarter ended January 31, 2010).

10.20 Form of Amendment No. 1 to Employment Agreement between Piedmont Natural Gas Company, Inc. and Thomas E. Skains, dated as of June 4, 2010 (Substantially identical agreements have been entered into as of the same date with David J. Dzuricky, Kevin M. O'Hara, Michael H. Yount and Franklin H. Yoho) (Exhibit 10.1, Form 10-Q for the quarter ended July 31, 2010).

10.21 Employment Agreement between Piedmont Natural Gas Company, Inc. and Karl W. Newlin, dated as of June 4, 2010 (Exhibit 10.2, Form 10-Q for the quarter ended July 31, 2010).

10.22 Severance Agreement between Piedmont Natural Gas Company, Inc. and Karl W. Newlin, dated as of June 4, 2010 (Exhibit 10.3, Form 10-Q for the quarter ended July 31, 2010).

Other Contracts:

10.23 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).

10.24 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).

10.25 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).

10.26 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).

10.27 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).

10.28 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).

10.29 Operating Agreement of Hardy Storage Company, LLC, dated as of November 12, 2004 (Exhibit 10.3, Form 8-K dated November 16, 2004).

10.30 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).

10.31 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).

10.32 Credit Agreement dated as of April 25, 2006 among Piedmont Natural Gas Company, Inc. and Bank of America, N.A. as Administrative Agent, Swing Line Lender and L/C Issuer, and The Other Lenders Party Hereto (Exhibit 10.4, Form 10-Q for the quarter ended July 31, 2010).

10.33 Revolving Credit Facility between Piedmont Natural Gas Company, Inc. and Bank of America, N.A., dated October 27, 2008 (Exhibit 10.32, Form 10-K for the fiscal year ended October 31, 2008).

10.34 Revolving Credit Facility between Piedmont Natural Gas Company, Inc. and Branch Banking and Trust Company, dated October 29, 2008 (Exhibit 10.33, Form 10-K for the fiscal year ended October 31, 2008).

10.35 Credit Agreement dated as of December 3, 2008 among Piedmont Natural Gas Company, Inc., Bank of America, N.A., as Administrative Agent, and the Other Lenders Party Thereto (Exhibit 10.5, Form 10-Q for the quarter ended July 31, 2010).

10.36	Amended and Restated Revolving Credit Facility dated December 1, 2008 between Piedmont Natural Gas Company, Inc. and Bank of America, N.A. (Exhibit 10.4, Form 10-Q for the quarter ended January 31, 2009).
10.37	Amended and Restated Revolving Credit Facility dated December 1, 2008 between Piedmont Natural Gas Company, Inc. and Branch Banking and Trust Company (Exhibit 10.5, Form 10-Q for the quarter ended January 31, 2009).
10.38	Second Amendment to Amended and Restated Limited Liability Company Agreement of SouthStar Energy Services LLC by and between Georgia Natural Gas Company and Piedmont Energy Company, dated July 2, 2009 (Exhibit 10.2, Form 10-Q for the quarter ended July 31, 2009).
10.39	Settlement Agreement by and between Georgia Natural Gas Company and Piedmont Energy Company, dated July 29, 2009 (Exhibit 10.1, Form 8-K dated August 4, 2009).
10.40	Third Amendment to Amended and Restated Limited Liability Company Agreement of SouthStar Energy Services LLC by and between Georgia Natural Gas Company and Piedmont Energy Company, dated July 29, 2009 (Exhibit 10.2, Form 8-K dated August 4, 2009).
10.41	Assignment and Assumption between Citibank, N.A. and Northern Trust Company, dated as of September 18, 2009 (Exhibit 10.37, Form 10-K for the fiscal year ended October 31, 2009).
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.
101.INS	XBRL Instance Document (1)
101.SCH	XBRL Taxonomy Extension Schema (1)
101.CAL	XBRL Taxonomy Calculation Linkbase (1)
101.DEF	XBRL Taxonomy Definition Linkbase (1)
101.LAB	XBRL Taxonomy Extension Label Linkbase (1)
101.PRE	XBRL Taxonomy Extension Presentation Linkbase (1)

(1) Furnished, not filed.

Attached as Exhibit 101 to this Annual Report are the following documents formatted in extensible business reporting language (XBRL): (1) Document and Entity Information; (2) Consolidated Balance Sheets as of October 31, 2010 and 2009; (3) Consolidated Statements of Income for the years ended October 31, 2010, 2009 and 2008; (4) Consolidated Statements of Cash Flows for the years ended October 31, 2010, 2009 and 2008; (5) Consolidated Statements of Stockholders' Equity for the years ended October 31, 2010, 2009 and 2008; and (6) Notes to Consolidated Financial Statements.

Pursuant to Rule 406T of Regulation S-T, these interactive data files are deemed not filed as part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933 or Section 18 of the Securities Exchange Act of 1934 and otherwise not subject to liability. We also make available on our web site the Interactive Data Files submitted as Exhibit 101 to this Annual Report.

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 23, 2010

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	Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)
Date: December 23, 2010	
/s/ David J. Dzuricky David J. Dzuricky	Senior Vice President and Chief Financial Officer (Principal Financial Officer)
Date: December 23, 2010	
/s/ Jose M. Simon Jose M. Simon	Vice President and Controller (Principal Accounting Officer)
Date: December 23, 2010	

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