PIEDMONT NATURAL GAS CO INC
Form 10-Q
June 09, 2006

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549
FORM 10-Q

(Mark One)

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

For the quarterly period ended April 30, 2006

or

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

For the Transition period from ____________________ to ____________________

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

North Carolina	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

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

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

Large Accelerated Filer þ Accelerated Filer o Non-accelerated Filer o

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

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

Class	Outstanding at June 2, 2006
Common Stock, no par value	75,277,520

PART 1. FINANCIAL INFORMATION

Item 1. Financial Statements
Piedmont Natural Gas Company, Inc. and Subsidiaries
Condensed Consolidated Balance Sheets (Unaudited)
(In thousands)

	April 30, 2006	October 31, 2005
ASSETS		
Utility Plant, at original cost	$ 2,699,460	$ 2,611,577
Less accumulated depreciation	700,299	672,502
Utility plant, net	1,999,161	1,939,075
Other Physical Property (net of accumulated depreciation of $1,969 in 2006 and $1,888 in 2005)	727	731
Current Assets:		
Cash and cash equivalents	20,330	7,065
Restricted cash		13,108
Trade accounts receivable (less allowance for doubtful accounts of $4,815 in 2006 and $1,188 in 2005)	182,027	107,535
Income taxes receivable	13,318	21,570
Other receivables	1,532	12,102
Unbilled utility revenues	27,598	48,414
Gas in storage	107,902	151,865
Gas purchase options, at fair value	1,471	22,843
Amounts due from customers	68,501	52,161
Prepayments	24,009	62,821
Other	5,346	5,427
Total current assets	452,034	504,911
Investments, Deferred Charges and Other Assets:		
Equity method investments in non-utility activities	80,331	71,520
Goodwill	47,383	47,383
Unamortized debt expense	4,973	4,822
Other	31,666	34,048
Total investments, deferred charges and other assets	164,353	157,773
Total	$ 2,616,275	$ 2,602,490

CAPITALIZATION AND LIABILITIES

Capitalization:		
Stockholders equity:		
Common stock, no par value, shares authorized: 200,000 in 2006 and 100,000 in 2005; outstanding: 75,255 in 2006 and 76,698 in 2005	$ 528,082	$ 562,880
Retained earnings	403,411	323,565
Accumulated other comprehensive income (loss)	(956)	(2,253)
Total stockholders equity	930,537	884,192
Long-term debt	625,000	625,000
Total capitalization	1,555,537	1,509,192
Current Liabilities:		
Current maturities of long-term debt	35,000	35,000
Notes payable	252,000	158,500
Trade accounts payable	73,710	182,847
Other accounts payable	28,118	45,325
Income taxes accrued		6,201
Deferred income taxes	38,182	23,128
General taxes accrued	7,906	16,450
Amounts due to customers	1,614	17,124
Other	47,139	43,989
Total current liabilities	483,669	528,564
Deferred Credits and Other Liabilities:		
Deferred income taxes	217,273	213,050
Unamortized federal investment tax credits	3,682	3,951
Regulatory cost of removal obligations	300,249	288,989
Other	55,865	58,744
Total deferred credits and other liabilities	577,069	564,734
Total	$ 2,616,275	$ 2,602,490

See notes to condensed consolidated financial statements.

Piedmont Natural Gas Company, Inc. and Subsidiaries
Condensed Consolidated Statements of Income (Unaudited)
(In thousands)

	Three Months Ended April 30		Six Months Ended April 30	
	2006	2005	2006	2005
Operating Revenues	$ 483,198	$ 508,035	$ 1,404,545	$ 1,188,591
Cost of Gas	329,188	367,378	1,041,163	845,314
Margin	154,010	140,657	363,382	343,277
Operating Expenses:				
Operations and maintenance	59,720	52,324	112,942	102,577
Depreciation	21,758	20,989	43,645	41,737
General taxes	8,061	7,332	16,771	15,773
Income taxes	20,271	19,098	64,663	63,357
Total operating expenses	109,810	99,743	238,021	223,444
Operating Income	44,200	40,914	125,361	119,833
Other Income (Expense):				
Income from equity method investments	20,165	14,647	25,916	20,460
Gain on sale of marketable securities		1,525		1,525
Allowance for equity funds used during construction		359		616
Non-operating income	266	106	285	521
Non-operating expense	(115)	(233)	(182)	(337)
Income taxes	(7,900)	(6,387)	(10,125)	(8,704)
Total other income (expense)	12,416	10,017	15,894	14,081
Utility Interest Charges	12,874	11,201	25,516	23,006
Income Before Minority Interest in Income of Consolidated Subsidiary	43,742	39,730	115,739	110,908
Less Minority Interest in Income (Loss) of Consolidated Subsidiary		98		(1)

Net Income	$ 43,742	$ 39,632	$ 115,739	$ 110,909
Average Shares of Common Stock:				
Basic	76,133	76,703	76,413	76,706
Diluted	76,371	76,915	76,651	76,920
Earnings Per Share of Common Stock:				
Basic	$ 0.57	$ 0.52	$ 1.51	$ 1.45
Diluted	$ 0.57	$ 0.52	$ 1.51	$ 1.44
Cash Dividends Per Share of Common Stock	$ 0.24	$ 0.23	$ 0.47	$ 0.445

See notes to condensed consolidated financial statements.

Piedmont Natural Gas Company, Inc. and Subsidiaries
Condensed Consolidated Statements of Cash Flows (Unaudited)
(In thousands)

	Six Months Ended April 30	
	2006	2005 (As Restated- See Note 15)
Cash Flows from Operating Activities:		
Net income	$ 115,739	$ 110,909
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	45,717	44,365
Amortization of investment tax credits	(269)	(272)
Allowance for doubtful accounts	3,627	5,997
Allowance for funds used during construction	(1,498)	(1,704)
Earnings from equity method investments	(25,916)	(20,460)
Distributions of earnings from equity method investments	24,473	21,164
Gain on sale of marketable securities		(1,525)
Deferred income taxes	18,448	20,582
Change in assets and liabilities	(109,120)	40,477
Net cash provided by operating activities	71,201	219,533
Cash Flows from Investing Activities:		
Utility construction expenditures	(100,753)	(84,399)
Reimbursements from bond fund	13,134	19,283
Contributions to equity method investments	(5,569)	(319)
Distributions of capital from equity method investments	158	794
Decrease (increase) in restricted cash	13,108	(147)
Proceeds from sale of marketable securities		2,394
Other	1,280	700
Net cash used in investing activities	(78,642)	(61,694)
Cash Flows from Financing Activities:		
Increase (decrease) in notes payable, net of expenses of $370 in 2006	93,130	(109,500)
Issuance of common stock through dividend reinvestment and employee stock plans	10,312	13,083
Repurchases of common stock	(46,779)	(12,979)
Dividends paid	(35,957)	(34,120)
Net cash provided by (used in) financing activities	20,706	(143,516)
Net Increase in Cash and Cash Equivalents	13,265	14,323
Cash and Cash Equivalents at Beginning of Period	7,065	5,676

Cash and Cash Equivalents at End of Period	$	20,330	$	19,999
Noncash Investing and Financing Activities:				
Utility construction expenditures	$	(5,150)	$	(1,701)

See notes to condensed consolidated financial statements.

Piedmont Natural Gas Company, Inc. and Subsidiaries
Condensed Consolidated Statements of Comprehensive Income (Unaudited)
(In thousands)

	Three Months Ended April 30		Six Months Ended April 30	
	2006	2005	2006	2005
Net Income	$ 43,742	$ 39,632	$ 115,739	$ 110,909
Other Comprehensive Income:				
Minimum pension liability adjustment, net of tax of ($1,778)				(2,748)
Reclassification adjustment of realized gain on marketable securities included in net income, net of tax of ($611)		(945)		(945)
Unrealized gain on marketable securities, net of tax of $220				348
Unrealized gain from hedging activities of equity method investments, net of tax of $664 and $492 for the three months ended April 30, 2006 and 2005, respectively, and $2,088 and $1,433 for the six months ended April 30, 2006 and 2005, respectively	1,042	730	3,283	2,229
Reclassification adjustment of realized gain from hedging activities of equity method investments included in net income, net of tax of ($1,049) and ($912) for the three months ended April 30, 2006 and 2005, respectively, and ($1,260) and ($1,129) for the six months ended April 30, 2006 and 2005	(1,653)	(1,418)	(1,986)	(1,689)
Total Comprehensive Income	$ 43,131	$ 37,999	$ 117,036	$ 108,104

See notes to condensed consolidated financial statements.

Piedmont Natural Gas Company, Inc. and Subsidiaries
Notes to Condensed Consolidated Financial Statements (Unaudited)

1. The condensed consolidated financial statements have not been audited. These financial statements should be read in conjunction with the Consolidated Financial Statements and Notes included in our Form 10-K for the year ended October 31, 2005.

2. In our opinion, the unaudited condensed consolidated financial statements include all normal recurring adjustments necessary for a fair statement of financial position at April 30, 2006 and October 31, 2005, the results of operations for the three months and six months ended April 30, 2006 and 2005, and cash flows for the six months ended April 30, 2006 and 2005. Our business is seasonal in nature. The results of operations for the three months and six months ended April 30, 2006, do not necessarily reflect the results to be expected for the full year.

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

3. We follow Statement of Financial Accounting Standards (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation (Statement 71). Statement 71 provides that rate-regulated public utilities account for and report assets and liabilities consistent with the economic effect of the manner in which independent third-party regulators establish rates. In applying Statement 71, we capitalize certain costs and benefits as regulatory assets and liabilities, respectively, in order to provide for recovery from or refund to utility customers in future periods. The amounts recorded as regulatory assets in the condensed consolidated balance sheets as of April 30, 2006 and October 31, 2005, were $100.2 million and $85.8 million, respectively. The amounts recorded as regulatory liabilities in the condensed consolidated balance sheets as of April 30, 2006 and October 31, 2005, were $327.9 million and $333.3 million, respectively.

Significant inter-company transactions have been eliminated in consolidation where appropriate; however, we have not eliminated inter-company profit on sales to affiliates and costs from affiliates in accordance with Statement 71. See Note 9 for information on related party transactions.

4. On November 3, 2005, the North Carolina Utilities Commission (NCUC) issued an order in a general rate case proceeding approving, among other things, an annual increase in margin of $20.2 million and authorizing new rates effective November 1, 2005. The order provided for the elimination of the weather normalization adjustment (WNA) mechanism in North Carolina and the establishment of a Customer Utilization Tracker (CUT). The CUT is experimental and can be effective for no more than three years, subject to review and approval in a future general rate case proceeding. The CUT provides for the recovery of our approved margin per customer independent of weather or other usage and consumption patterns of residential and commercial customers. The CUT tracks our margin earned monthly and will result in semi-annual rate adjustments to refund any over-collection or recover any under-collection. On March 17, 2006, we made our first rate adjustment filing to collect, beginning April 1, $11.8 million attributable to the period ended January 31, 2006.

On January 3, 2006, the North Carolina Office of the Attorney General filed a notice of appeal in the general rate case proceeding challenging the lawfulness of the NCUC s authorization and approval of the CUT. On April 6, the Attorney General filed a Notice of Appeal and Exceptions to the NCUC s March 28, 2006, order approving the first adjustment filing under the CUT. This appeal is not substantively different from the appeal of the CUT mechanism. We believe the CUT is lawful, just and reasonable and reflects good public policy, and we intend to vigorously defend the NCUC s action authorizing and approving the CUT. We have entered into settlement negotiations with the Attorney General s office. We are unable to predict the outcome of the appeals, the settlement discussions or any potential impact to our rates, charges or terms and conditions of service should the NCUC orders be reversed or remanded.

5. On April 7, 2006, we entered into an accelerated share repurchase program whereby we purchased and retired 1 million shares of our common stock from an investment bank at the closing price that day of $23.87 per share. Total consideration paid to purchase the shares of $23.9 million, including $30,000 in commissions and other fees, was recorded in Stockholders Equity as a reduction in Common Stock.

As part of the accelerated share repurchase, we simultaneously entered into a forward sale contract with the investment bank that was expected to mature in approximately 50 trading days. Under the terms of the forward sale contract, the investment bank is required to purchase, in the open market, 1 million shares of our common stock during the term of the contract to fulfill its obligation related to the shares it borrowed from third parties and sold to us. At settlement, we, at our option, are required to either pay cash or issue registered or unregistered shares of our common stock to the investment bank if the investment bank s weighted average purchase price is higher than the April 7, 2006, closing price. The investment bank is required to pay us either cash or shares of our common stock, at our option, if the investment bank s weighted average price for the shares purchased is lower than the April 7, 2006, closing price. The amount of the payment is the difference between the investment bank s weighted average price per share and $23.87 per share multiplied by 1 million shares.

We accounted for the forward sale contract as an equity instrument under the provisions of Emerging Issues Task Force (EITF) Issue No. 00-19, Accounting for Derivative Financial Instruments Indexed to, and Potentially Settled in, a Company s Own Stock. As the fair value of the forward sale contract at inception was zero, no accounting for the forward sale contract is required until settlement, as long as the forward sale continues to meet the requirements for classification as an equity instrument. As of April 30, 2006, the investment bank had purchased 386,100 shares at a cumulative weighted average price of $24.32 per share. Subsequent to the quarter ended April 30, 2006, the investment bank purchased the remaining 613,900 shares which resulted in a cumulative weighted average price of $24.26 per share. At settlement on June 6, we paid cash of $.4 million to the investment bank, recorded in Common Stock in Stockholders Equity, since the weighted average purchase price was higher than the April 7, 2006, closing price of $23.87.

6. We compute basic earnings per share using the weighted average number of shares of common stock outstanding during each period. A reconciliation of basic and diluted earnings per share for the three months and six months ended April 30, 2006 and 2005, is presented below.

	Three Months		Six Months	
In thousands except per share amounts	2006	2005	2006	2005
Net Income	$ 43,742	$ 39,632	$ 115,739	$ 110,909
Average shares of common stock outstanding for basic earnings per share	76,133	76,703	76,413	76,706
Contingently issuable shares:				
Long-Term Incentive Plan	234	212	236	214
Accelerated Share Repurchase Program	4		2	
Average shares of dilutive stock	76,371	76,915	76,651	76,920
Earnings Per Share:				
Basic	$ .57	$ .52	$ 1.51	$ 1.45

Diluted	$	.57	$	.52	$	1.51	$	1.44

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7. Components of the net periodic benefit cost for our defined-benefit pension plans and our postretirement health care and life insurance benefits plan for the three months and six months ended April 30, 2006 and 2005, are presented below.

	Pension Benefits		Other Benefits	
In thousands	2006	2005	2006	2005
Three Months				
Service cost	$ 3,149	$ 2,312	$ 409	$ 311
Interest cost	3,971	2,628	629	480
Expected return on plan assets	(4,987)	(3,402)	(421)	(230)
Amortization of transition obligation			240	196
Amortization of prior-service cost	268	191		287
Amortization of actuarial (gain) loss	224	78	(82)	
Net periodic benefit cost	$ 2,625	$ 1,807	$ 775	$ 1,044
Six Months				
Service cost	$ 6,298	$ 4,624	$ 818	$ 622
Interest cost	7,942	5,256	1,258	960
Expected return on plan assets	(9,974)	(6,804)	(842)	(460)
Amortization of transition obligation			480	392
Amortization of prior-service cost	536	382		574
Amortization of actuarial (gain) loss	448	156	(164)	
Net periodic benefit cost	$ 5,250	$ 3,614	$ 1,550	$ 2,088

We estimate that we will contribute $15 million to the pension plans and $2.6 million to the other postretirement benefits plan in 2006.

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

We evaluate the performance of the regulated utility segment based on operating income. We evaluate the performance of the non-utility activities segment based on earnings from the ventures. The basis of segmentation and the basis of the measurement of segment profit or loss are the same as reported in the consolidated financial statements for the year ended October 31, 2005.

Operations by segment for the three months and six months ended April 30, 2006 and 2005, are presented below.

	Regulated Utility		Non-utility Activities		Total	
In thousands	2006	2005	2006	2005	2006	2005
Three Months						
Revenues from external customers	$ 483,198	$ 508,035	$	$	$ 483,198	$ 508,035
Operating income (loss)	64,471	60,012	(33)	(124)	64,438	59,888
Income from equity method investments			20,165	14,647	20,165	14,647
Income before income taxes and minority interest	51,882	49,232	20,031	15,983	71,913	65,215
Six Months						
Revenues from external customers	$1,404,545	$1,188,591	$	$	$1,404,545	$1,188,591
Operating income (loss)	190,024	183,190	(205)	(258)	189,819	182,932
Income from equity method investments			25,916	20,460	25,916	20,460
Income before income taxes and minority interest	165,023	161,378	25,504	21,591	190,527	182,969

Reconciliations to the condensed consolidated statements of income for the three months and six months ended April 30, 2006 and 2005, are presented below.

	Three Months		Six Months	
In thousands	2006	2005	2006	2005
Operating Income:				
Segment operating income	$ 64,438	$ 59,888	$ 189,819	$ 182,932
Utility income taxes	(20,271)	(19,098)	(64,663)	(63,357)
Non-utility activities	33	124	205	258
Operating income	$ 44,200	$ 40,914	$ 125,361	$ 119,833
Net Income:				
Income before income taxes and minority interest for reportable segments	$ 71,913	$ 65,215	$ 190,527	$ 182,969
Income taxes	(28,171)	(25,485)	(74,788)	(72,061)
Less minority interest		98		(1)
Net income	$ 43,742	$ 39,632	$ 115,739	$ 110,909

9. The condensed 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 condensed consolidated balance sheets. Earnings or losses from equity method investments are included in Income from equity method investments in the condensed consolidated statements of income.

We own 21.49% of the membership interests in Cardinal Pipeline Company, L.L.C., a North Carolina limited liability company. Cardinal owns and operates an intrastate natural gas pipeline in North Carolina and is regulated by the NCUC. We have related party transactions as a transportation customer of Cardinal, and we record in cost of gas the transportation costs charged by Cardinal. These gas costs for the three months and six months ended April 30, 2006 and 2005, are presented below.

	Three Months		Six Months	
In thousands	2006	2005	2006	2005
Transportation Costs	$ 1,142	$ 1,142	$ 2,323	$ 2,323

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As of April 30, 2006 and October 31, 2005, we owed Cardinal $.4 million.
We own 40% of the membership interests in Pine Needle LNG Company, L.L.C., a North Carolina limited liability company. Pine Needle owns an interstate liquefied natural gas (LNG) storage facility in North Carolina and is regulated by the Federal Energy Regulatory Commission (FERC). 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. These gas costs for the three months and six months ended April 30, 2006 and 2005, are presented below.

	Three Months		Six Months	
In thousands	2006	2005	2006	2005
Storage Costs	$ 3,059	$ 3,011	$ 6,222	$ 6,114

As of April 30, 2006 and October 31, 2005, we owed Pine Needle $1 million and $1.1 million, respectively.
We own 30% of the membership interests in SouthStar Energy Services LLC, a Delaware limited liability company. Under the terms of an amended and restated limited liability company operating agreement effective January 1, 2004, earnings and losses are allocated 25% to us and 75% to the other member. SouthStar sells natural gas to residential, commercial and industrial customers in the southeastern United States; however, SouthStar conducts most of its business in the unregulated retail gas market in Georgia. We have related party transactions as we sell wholesale gas supplies to SouthStar, and we record in operating revenues the amounts billed to SouthStar. Our operating revenues from these sales for the three months and six months ended April 30, 2006 and 2005, are presented below.

	Three Months		Six Months	
In thousands	2006	2005	2006	2005
Operating Revenues	$ 7,346	$ 2,485	$ 15,913	$ 6,009

As of April 30, 2006 and October 31, 2005, SouthStar owed us $1.5 million and $.9 million, respectively.
10. We have purchased and sold financial options for natural gas in all three states for our gas purchase portfolios. The gains or losses on financial derivatives utilized in the regulated utility segment ultimately will be included in our rates to customers. Current period changes in the assets and liabilities from these risk management activities are recorded as a component of gas costs in amounts due to/from customers in accordance with Statement 71. Accordingly, there is no earnings impact on the regulated utility segment as a result of the use of these financial derivatives. The fair value of gas purchase options decreased from $22.8 million as of October 31, 2005, to $1.5 million as of April 30, 2006, primarily due to options being exercised or options expiring during the period and being replaced with options having lower market values.
11. On April 24, 2006, we replaced our expiring $250 million 364-day committed lines of credit with a syndicated five-year revolving credit facility that includes annual renewal options. The credit facility has aggregate commitments totaling $350 million, which may be increased up to $600 million. This facility includes letters of credit. We pay an annual fee of $35,000 plus six basis points for any unused amount up to $350 million. Outstanding short-term borrowings increased from $158.5 million as of October 31, 2005, to $252 million as of April 30, 2006, as cash requirements during the period resulted in higher outstanding borrowings. During the three months ended April 30, 2006, short-term borrowings ranged from $140 million to $333 million, and interest rates ranged from 4.72% to 5.29% (weighted average of 4.98%). During the six months ended April 30, 2006, short-term borrowings ranged from $115 million to $378.5 million, and interest

rates ranged from 4.07% to 5.29% (weighted average of 4.76%). Our credit facility s financial covenants require us to maintain a ratio of total debt to total capitalization of no greater than 70%.

12. On April 13, 2006, we announced plans to restructure our management group. The restructuring plans are part of an ongoing, larger effort aimed at streamlining business processes, capturing operational and organizational efficiencies and improving customer service. The restructuring began with an offer of early retirement for 23 employees in our management group, and will eventually include the further consolidation and reorganization of management positions and functions. The program s cost is estimated to be $7 to 8 million.

During the quarter ended April 30, 2006, we recognized a liability and an expense of $4.4 million which was included in operations and maintenance expense for the cost of the early retirement program. Due to the short discount period, the liability for the program was recorded at its gross value. Additional costs will be accrued in the third quarter ending July 31 as the restructuring effort is completed for all management positions.

13. At our annual meeting of shareholders held March 3, 2006, shareholders approved the Piedmont Natural Gas Company, Inc. Incentive Compensation Plan (Plan) effective November 1, 2005. The Plan permits the grant of annual incentive awards, performance awards, restricted stock, stock options and stock appreciation rights to eligible employees and members of the Board of Directors. As of April 30, 2006, no awards have been granted under the Plan.

14. In March 2005, the Financial Accounting Standards Board (FASB) issued Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations (FIN 47), to clarify the term conditional asset retirement as used in SFAS No. 143, Accounting for Asset Retirement Obligations. FIN 47 requires that a liability be recognized for the fair value of a conditional asset retirement obligation when incurred, if the fair value of the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional asset retirement obligation would be factored into the measurement of the liability when sufficient information exists. This interpretation is effective no later than the end of fiscal years ending after December 15, 2005. Accordingly, we will adopt FIN 47 no later than our fourth fiscal quarter in 2006. We are currently assessing the impact FIN 47 may have on our consolidated balance sheet; however, we believe the adoption of FIN 47 will not have a material impact on our financial position, results of operations or cash flows.

In April 2006, the FASB issued FASB Staff Position No. FIN 46(R)-6, Determining the Variability to Be Considered in Applying FASB Interpretation No. 46(R) (FIN 46(R)-6). FIN 46(R)-6 addresses how a reporting enterprise should determine the variability to be considered in applying FASB Interpretation No. 46(R) (revised December 2003), Consolidation of Variable Interest Entities (VIEs) (FIN 46(R)), by evaluating the entity s design. FIN 46(R)-6 provides guidance regarding how contracts or arrangements that create or reduce variability should be considered when determining whether entities qualify as VIEs. This interpretation addresses consolidation by business enterprises of entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. Under FIN 46(R)-6, consolidation of a VIE by the primary beneficiary is required if it is determined that the VIE does not effectively disperse risks among the parties involved. The primary beneficiary is the party that has either a majority of the expected losses or a majority of the expected residual returns of such entity, as defined. The guidance of FIN 46(R)-6 must be applied on a prospective basis in reporting periods beginning after June 15, 2006, which would be our fourth fiscal quarter. The new requirements do not need to be applied to existing entities unless a reconsideration event occurs. We are currently evaluating the impact of adopting FIN 46(R)-6.

15. Subsequent to the issuance of our condensed consolidated financial statements for the period ended April 30, 2005, management identified errors in the condensed consolidated statement of cash flows relating to

distributions of earnings received from equity method investees, changes in restricted cash and the amounts reported as construction expenditures. As a result, the accompanying condensed consolidated statement of cash flows for the six months ended April 30, 2005, has been restated from the amounts previously reported to correct the presentation of these items. The restatement did not affect previously reported operating income, net income, earnings per share or stockholders equity.

A summary of the significant effects of the restatement of the condensed consolidated statement of cash flows for the six months ended April 30, 2005, is as follows:

In thousands	As Previously Reported	As Restated
Cash flows from operating activities:		
Distributions of earnings from equity method investments	$	$ 21,164
Net cash provided by operating activities	196,521	219,533
Cash flows from investing activities:		
Distributions of capital from equity method investments	21,958	794
Decrease (increase) in restricted cash		(147)
Net cash used in investing activities	(38,682)	(61,694)

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion gives effect to the restatement of the condensed consolidated statement of cash flows discussed in Note 15 to the condensed consolidated financial statements.

Overview

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

The regulated utility segment is the largest segment of our business with approximately 95% of our consolidated assets. This segment is regulated by three state regulatory commissions that approve rates and tariffs that are designed to give us the opportunity to generate revenues to cover our gas and non-gas costs and to earn a fair rate of return for our shareholders. Factors critical to the success of the regulated utility include a safe, reliable natural gas distribution system and the ability to recover the costs and expenses of the business in rates charged to customers. For the six months ended April 30, 2006, 87% of our earnings before taxes came from our regulated utility segment.

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

Weather conditions directly influence the volumes of natural gas delivered by the regulated utility. Significant portions of our revenues are generated during the winter season. During warm winters or unevenly cold winters, heating customers may significantly reduce their consumption of natural gas. Through October 31, 2005, we had weather normalization adjustment (WNA) mechanisms in all states 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 a general rate case proceeding during 2005, the NCUC ordered the establishment of a Customer Utilization Tracker (CUT) and the elimination of the WNA effective November 1, 2005. The CUT provides for the recovery of our approved margin per customer independent of weather or other usage and consumption patterns of residential and commercial customers. For further information, see Our Business in Management s Discussion and Analysis of Financial Condition and Results of Operations.

Over the past few years, there have been significant increases in the wholesale cost of natural gas. The relationship between supply and demand has the greatest impact on wholesale gas prices. Increased prices of natural gas are being driven by increased demand that is exceeding the growth in accessible supply. Continued high gas prices could shift our customers preference away from natural gas toward other energy sources, particularly in the industrial market. High gas prices could also affect consumption levels as customers react to high bills. We expect that the wholesale price of natural gas will remain high and volatile until natural gas supply and demand are in better balance.

The majority of our natural gas supplies come from the Gulf Coast region. We believe that diversification of our supply portfolio is in our customers best interest. We have a firm transportation contract pending for additional pipeline capacity that will provide access to Canadian and Rocky Mountain gas supplies via the Chicago hub, primarily to serve our Tennessee markets. It is anticipated that this new capacity will be available for the 2006-2007 winter. We have also executed an agreement with Hardy Storage Company LLC for market-area storage capacity in West Virginia with an anticipated in-service date in 2007.

Although we have been operating in a relatively low-interest-rate environment for both short- and long-term debt financing during the past few years, the federal funds rate has steadily increased and is the highest it has been in over four years. As interest rates rise, we will continue to see increases in rates on our borrowings.

Part of our strategic plan is to manage our gas distribution business through sound rate and regulatory initiatives, control of our operating costs and implementation of new technologies. We are working to enhance the value and growth of our utility assets by good management of capital spending, including improvements for current customers and the pursuit of customer growth opportunities in our service areas. We strive for quality customer service by investing in systems, 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 strategic plan includes a focus on maintaining a debt-to-capitalization ratio within a range of 45 to 50%. We will continue to stress the importance of maintaining a strong balance sheet and investment-grade credit ratings to support our operating and investment needs.

As part of an ongoing, larger effort aimed at streamlining business processes, capturing operational and organizational efficiencies and improving customer service, we announced plans to restructure our management group on April 13, 2006. We expect the restructuring to generate savings of $5 to 6 million annually beginning in fiscal 2007. For further information, see Note 12 to the condensed consolidated financial statements.

Results of Operations

Operating Revenues

Operating revenues decreased $24.8 million for the three months ended April 30, 2006, compared with the similar period in 2005 primarily due to the following:

$43.2 million decrease resulting from a 12% decrease, 7.2 million dekatherms, in volumes delivered primarily due to warmer weather and customer conservation.

$16 million increase from the CUT mechanism.

$6.1 million reduction in WNA credits from the similar prior period.

Operating revenues increased $216 million for the six months ended April 30, 2006, compared with the similar period in 2005 primarily due to the following increases:

$268.8 million from increased commodity gas costs passed through to customers.

$20.1 million from rate design changes in North Carolina and South Carolina effective November 1, 2005.

$25.6 million net increase in North Carolina resulting from $29.3 million from the CUT mechanism compared with $3.7 million of WNA surcharges for the similar prior period. For further discussion of the regulatory mechanisms effective November 1, 2005, see Our Business in Management s Discussion and Analysis of Financial Condition and Results of Operations.

These increases were partially offset by a decrease of $113.3 million resulting from a 10% decrease, 12.8 million dekatherms, in volumes delivered primarily due to warmer weather and customer conservation.

Cost of Gas

Cost of gas decreased $38.2 million for the three months ended April 30, 2006, compared with the similar period in 2005 primarily due to decreases of $31.4 million resulting from a decrease in volumes delivered of 7.2 million dekatherms and $3.2 million from secondary market transactions. These decreases were partially offset by an increase of $2 million from increased commodity gas costs.

Cost of gas increased $195.8 million for the six months ended April 30, 2006, compared with the similar period in 2005 primarily due to increases of $268.8 million from increased commodity gas costs and $9.3 million from secondary market transactions. These increases were partially offset by a decrease of $88.2 million resulting from a decrease in volumes delivered of 12.8 million dekatherms.

Under purchased gas adjustment (PGA) procedures in all three states, we revise rates periodically without formal rate proceedings to reflect changes in the wholesale cost of gas. Charges 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 added to or deducted from cost of gas and included in Amounts due from customers or Amounts due to customers in the condensed consolidated balance sheets.

In North Carolina and South Carolina, recoveries of gas costs are subject to annual gas cost recovery proceedings to determine the prudence of our gas purchases. We have been found prudent in all such past proceedings.

Margin

Margin increased $13.4 million for the three months ended April 30, 2006, and $20.1 million for the six months ended April 30, 2006, compared with the similar periods in 2005 primarily due to growth in the residential and commercial customer base and the impact of changes in rate design and regulatory mechanisms effective November 1, 2005. These increases were partially offset by decreased consumption primarily due to warmer weather and customer conservation. Implementation of the CUT has partially mitigated both these factors in North Carolina.

Operations and Maintenance Expenses

Operations and maintenance expenses increased $7.4 million for the three months ended April 30, 2006, compared with the similar period in 2005 primarily due to the following increases:

- $4.4 million in restructuring costs associated with the early retirement program.
- $2 million in outside services for the customer service contact center.
- $.9 million in payroll costs due to an increase in the costs associated with customer service and accrued long-term incentive plan liability.
- $.7 million in employee benefits expense primarily due to increases in pension and group health insurance costs, partially offset by decreases in postretirement health care and life insurance costs.
- $.6 million in rents and leases due to the new corporate office space and telecommunications costs.
- $.4 million in conservation programs ordered by the NCUC.

These increases were partially offset by a decrease of $1.3 million in the provision for uncollectibles. Effective November 1, 2005, the NCUC approved the recovery of all uncollected gas costs through the gas cost deferred account. As a result, only the portion of accounts written off relating to non-gas costs, or margin, is included in base rates and, accordingly, only this portion is included in the provision for uncollectibles expense. A similar mechanism has been in place for our Tennessee operations since March 2004 whereby uncollected gas costs in excess of, or less than, those allowed in base rates are recovered from, or refunded to, customers through PGA procedures.

Operations and maintenance expenses increased $10.4 million for the six months ended April 30, 2006, compared with the similar period in 2005 primarily due to the following increases:

- $4.4 million in restructuring costs associated with the early retirement program.
- $2.6 million in outside services for the customer service contact center and for the move to the new corporate office building.
- $1.5 million in payroll costs due to an increase in the costs associated with customer service and accrued long-term incentive plan liability.
- $1.5 million in employee benefits expense primarily due to increases in pension and group health insurance costs, partially offset by decreases in postretirement health care and life insurance costs.
- $1.4 million in rents and leases due to the new corporate office space and telecommunications costs.
- $.4 million in conservation programs ordered by the NCUC.
- $.5 million in regulatory expense primarily due to fees to our state regulatory commissions that are based on revenues.

These increases were partially offset by a decrease of $2.1 million in the provision for uncollectibles.

Depreciation

Depreciation expense increased $.8 million for the three months ended April 30, 2006, and $1.9 million for the six months ended April 30, 2006, compared with the similar periods in 2005 primarily due to increases in plant in service.

General Taxes

General taxes increased $.7 million for the three months ended April 30, 2006, and $1 million for the six months ended April 30, 2006, compared with the similar periods in 2005 primarily due to increases in property

taxes resulting from higher tax values and tax rates.

Other Income (Expense)

Income from equity method investments increased $5.5 million for the three months and six months ended April 30, 2006, compared with the similar periods in 2005 primarily due to increases in earnings from SouthStar.

Gain on Sale of Marketable Securities

For the three months and six months ended April 30, 2005, the gain on sale of marketable securities resulted from the sale in February 2005 of 37,244 common units of Energy Transfer Partners, L.P., which we acquired in connection with the sale of our propane interests in January 2004. Total proceeds from the sale were $2.4 million and resulted in a before-tax gain of $1.5 million.

Utility Interest Charges

Utility interest charges increased $1.7 million for the three months ended April 30, 2006, compared with the similar period in 2005 primarily due to the following:

- $2.4 million increase in interest on short-term debt due to higher balances outstanding at interest rates that were approximately two percentage points higher in the current period. See further discussion in Financial Condition and Liquidity.

- $.6 million decrease in net interest expense on amounts due to/from customers due to higher net receivables in 2006.

Utility interest charges increased $2.5 million for the six months ended April 30, 2006, compared with the similar period in 2005 primarily due to the following:

- $4.2 million increase in interest on short-term debt due to higher balances outstanding at interest rates that were approximately two percentage points higher in the current period.

- $1.4 million decrease in net interest expense on amounts due to/from customers due to higher net receivables in 2006.

Our Business

Piedmont Natural Gas Company, Inc., is an energy services company primarily engaged in the distribution of natural gas to 990,000 residential, commercial and industrial customers in portions of North Carolina, South Carolina and Tennessee, including 61,000 customers served by municipalities who are our wholesale customers. We are invested in joint venture, energy-related businesses, including unregulated retail natural gas marketing, interstate natural gas storage and intrastate natural gas transportation.

We continually assess the nature of our business and explore alternatives to traditional utility regulation. Non-traditional ratemaking initiatives and market-based pricing of products and services provide additional challenges and opportunities for us. We also regularly evaluate opportunities for obtaining natural gas supplies from different production regions and supply sources to maximize our natural gas portfolio flexibility and reliability, including the diversification of our supply portfolio through pipeline capacity arrangements that access new sources of supply and market-area storage and that diversify supply concentration away from the Gulf Coast region. We have a firm transportation contract pending with Midwestern Gas Transmission Company for 120,000 dekatherms per day of additional pipeline capacity that will provide access to Canadian and Rocky Mountain gas supplies via the Chicago hub, primarily to serve our Tennessee markets. It is anticipated to be in-service for the 2006-2007 winter. We have also executed an agreement with Hardy Storage Company LLC for market-area storage capacity in West Virginia with an anticipated in-service date in 2007. We have a 50% equity interest in this project.

We have two reportable business segments, regulated utility and non-utility activities. For further information on business segments, see Note 8 to the condensed consolidated financial statements.

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

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

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

On January 3, 2006, the North Carolina Office of the Attorney General filed a notice of appeal in the general rate case proceeding challenging the lawfulness of the NCUC s authorization and approval of the CUT. On April 6, the Attorney General filed a Notice of Appeal and Exceptions to the NCUC s March 28, 2006, order approving the first adjustment filing under the CUT. This appeal is not substantively different from the appeal of the CUT mechanism. We believe the CUT is lawful, just and reasonable and reflects good public policy, and we intend to vigorously defend the NCUC s action authorizing and approving the CUT. We have entered into settlement negotiations with the Attorney General s office. We are unable to predict the outcome of the appeals, the settlement discussions or any potential impact to our rates, charges or terms and conditions of service should the NCUC orders be reversed or remanded.

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

Financial Condition and Liquidity

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

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

During the peak heating season, our accounts payable increase to reflect amounts due to our natural gas suppliers for commodity and pipeline capacity. The value of the gas can vary significantly from period to period due to volatility in the price of natural gas. Our natural gas costs and amounts due to/from customers represent the difference between natural gas costs that we have paid to suppliers and amounts that we have collected from customers. These natural gas costs can cause cash flows to vary significantly from period to period.

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 consumption. Temperatures above normal can lead to reduced operating cash flows, thereby increasing the need for short-term borrowings to meet current cash requirements.

Net cash provided by operating activities was $71.2 million and $219.5 million for the six months ended April 30, 2006 and 2005, respectively. Our cash needs for working capital have increased substantially as a result of significant increases in the wholesale prices of natural gas. Net cash provided by operating activities reflects a $4.8 million increase in net income for the six months ended April 30, 2006, compared with the similar 2005 period, as well as changes in working capital as described below:

Trade accounts receivable and unbilled utility revenues increased $19.4 million, primarily due to higher commodity gas costs in the 2005-2006 winter heating season even though the current winter period was 9% warmer than normal and 5% warmer than the similar prior period.

Inventories decreased $10 million primarily due to reduced withdrawals as warmer weather was experienced during the current period.

Trade accounts payable generated a use of cash of $104 million in the current period compared with a source of cash of $16.6 million in the prior period primarily due to an increase in wholesale natural gas prices.

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 currently have petitions before our regulatory commissions that would place further credit requirements on the retail natural gas marketers using our system.

The regulated utility competes with other energy products, such as electricity and propane, in the residential and commercial customer markets. The most significant product competition is with electricity for space heating, water heating and cooking. Numerous factors can influence customer demand for natural gas, such as price volatility, the availability of natural gas in relation to other energy forms, general economic conditions, weather, energy conservation, the ability to convert from natural gas to other energy sources, and legislation. 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. With a tighter balance between domestic supply and demand, the cost of natural gas from non-domestic sources may play a greater role in establishing the future market price of natural gas. The price of oil depends upon a number of factors beyond our control, including the relationship between supply and demand and the policies of foreign and domestic governments and organizations. Our liquidity could be impacted, either positively or negatively, as a result of alternate fuel decisions made by industrial customers.

Cash Flows from Investing Activities. Net cash used in investing activities was $78.6 million and $61.7 million for the six months ended April 30, 2006 and 2005, respectively. Net cash used in investing activities was primarily for utility construction expenditures. Gross utility construction expenditures for the six months ended April 30, 2006, were $100.8 million, a 19% increase over the $84.4 million in 2005, primarily due to expenditures for the automated meter reading project. Reimbursements from the bond fund decreased $6.1 million from 2005 as construction of gas infrastructure in eastern North Carolina is nearing completion. Due to projected growth in our service areas, significant utility construction expenditures are expected to continue and are a part of our long-range forecasts that are prepared at least annually and typically cover a forecast period of five years.

During the six months ended April 30, 2006, we contributed $5.6 million to Hardy Storage Company LLC, an investee of one of our subsidiaries, for construction of the storage facility. We will make an additional cash contribution in the third quarter of 2006 of $18.1 million.

During the six months ended April 30, 2006, the restrictions on cash totaling $13.1 million were removed in connection with implementing the NCUC order in the general rate proceeding discussed in Note 4 to the condensed consolidated financial statements. As ordered by the NCUC, such cash had been held in an expansion fund to extend natural gas service to unserved areas of the state.

Cash Flows from Financing Activities. Net cash provided by (used in) financing activities was $20.7 million and ($143.5) million for the six months ended April 30, 2006 and 2005, respectively. Funds are primarily provided from bank borrowings and the issuance of common stock through dividend reinvestment and employee stock plans, net of purchases under the common stock repurchase program. We sell common stock

and long-term debt to cover cash requirements when market and other conditions favor such long-term financing.
As of April 30, 2006, we had committed lines of credit of $350 million with the ability to expand up to $600 million. Outstanding short-term borrowings increased from $158.5 million as of October 31, 2005, to $252 million as of April 30, 2006, as working capital needs during the period resulted in higher outstanding borrowings under our short-term lines of credit. During the six months ended April 30, 2006, short-term borrowings ranged from $115 million to $378.5 million, and interest rates ranged from 4.07% to 5.29% (weighted average of 4.76%).
As of April 30, 2006, we had a line of credit for letters of credit of $5 million under our new syndicated five-year revolving credit facility, of which $1.2 million were issued and outstanding. These letters of credit are used to guarantee claims from self-insurance under our general liability policies.
The level of short-term borrowings can vary significantly due to changes in the wholesale prices of natural gas and to the level of purchases of natural gas supplies to serve customer demand and for storage. Short-term debt may increase when wholesale prices for natural gas increase because we must pay suppliers for the gas before we collect our costs from customers through their monthly bills. Gas prices could continue to increase and fluctuate. If wholesale gas prices remain high, we may incur more short-term debt to pay for natural gas supplies and other operating costs since collections from customers could be slower and some customers may not be able to pay their gas bills on a timely basis.
During the six months ended April 30, 2006, we issued $10.3 million of common stock through dividend reinvestment and stock purchase plans. On April 7, 2006, we entered into an accelerated share repurchase (ASR) program and repurchased and retired 1 million shares of common stock for $23.9 million. Through the ASR program, we will repurchase and subsequently retire approximately four million shares of common stock over a four-year period, including the 1 million shares repurchased in April 2006. These repurchases are in addition to shares that are repurchased on a normal basis through the open market program. Under the Common Stock Open Market Purchase Program, we paid $46.8 million during the six months ended April 30, 2006, for 2 million shares of common stock, including the shares under the ASR, that are available for reissuance to these plans. During the six months ended April 30, 2005, .6 million shares were repurchased for $13 million.
We have paid quarterly dividends on our common stock since 1956. The amount of cash dividends that may be paid is restricted by provisions contained in certain note agreements under which long-term debt was issued. As of April 30, 2006, none of our retained earnings was restricted. On June 7, 2006, the Board of Directors declared a quarterly dividend on common stock of $.24 per share, payable July 14 to shareholders of record at the close of business on June 22.
As of April 30, 2006, our capitalization, including current maturities of long-term debt, consisted of 41% in long-term debt and 59% in common equity. Our long-term targeted capitalization ratio is 45-50% in long-term debt and 50-55% in common equity.
In July 2006, we expect to make the scheduled payment of $35 million on the 9.44% senior notes. Depending upon our needs for long-term financing and current market conditions, we expect to issue approximately $200 million of long-term debt in our fiscal third quarter in 2006 under a shelf registration which has a remaining balance of $309.4 million.
Credit ratings impact our ability to obtain short-term and long-term financing and the cost of such financings. In determining our credit ratings, the rating agencies consider a number of quantitative factors, including debt

to total capitalization, operating cash flows relative to outstanding debt, operating cash flow coverage of interest and pension liabilities and funding status. Rating agencies also consider qualitative factors, such as the consistency of our earnings over time, the quality of management and business strategy, the risks associated with our utility and non-utility businesses and the regulatory commissions that establish rates in the states where we operate.

As of April 30, 2006, all of our long-term debt was unsecured. Our long-term debt is rated A by Standard & Poor s Ratings Services and A3 by Moody s Investors. Currently, with respect to our long-term debt, the credit agencies maintain their stable outlook. There is no guarantee that a rating will remain in effect for any given period of time or that a rating will not be lowered or withdrawn by a rating agency if, in its judgment, circumstances warrant a change.

We are subject to default provisions related to our long-term debt and short-term borrowings. Failure to satisfy any of the default provisions would result in total outstanding issues of debt becoming due. There are cross-default provisions in all our debt agreements. As of April 30, 2006, we are in compliance with all default provisions.

Estimated Future Contractual Obligations

During the three months ended April 30, 2006, there were no material changes to our estimated future contractual obligations that were disclosed in our Form 10-K for the year ended October 31, 2005, in Management s Discussion and Analysis of Financial Condition and Results of Operations.

Off-balance Sheet Arrangements

Piedmont has no off-balance sheet arrangements other than operating leases that were discussed in Note 7 to the consolidated financial statements in our Form 10-K for the year ended October 31, 2005.

Critical Accounting Policies and Estimates

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

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

Management is responsible for the selection of the critical accounting estimates presented in our Form 10-K for the year ended October 31, 2005, in Management s Discussion and Analysis of Financial Condition and Results of Operations. Management has discussed these critical accounting estimates with the Audit Committee of the Board of Directors. There have been no changes in our critical accounting policies and estimates since October 31, 2005.

Recent Accounting Pronouncements

In March 2005, the FASB issued Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations (FIN 47), to clarify the term conditional asset retirement as used in SFAS No. 143, Accounting for Asset Retirement Obligations. FIN 47 requires that a liability be recognized for the fair value of a conditional asset retirement obligation when incurred, if the fair value of the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional asset retirement obligation would be factored into the measurement of the liability when sufficient information exists. This interpretation is effective no later than the end of fiscal years ending after December 15, 2005. Accordingly, we will adopt FIN 47 no later than our fourth fiscal quarter in 2006. We are currently assessing the impact FIN 47 may have on our consolidated balance sheet; however, we believe the adoption of FIN 47 will not have a material impact on our financial position, results of operations or cash flows.

In April 2006, the FASB issued FASB Staff Position No. FIN 46(R)-6, Determining the Variability to Be Considered in Applying FASB Interpretation No. 46(R) (FIN 46(R)-6). FIN 46(R)-6 addresses how a reporting enterprise should determine the variability to be considered in applying FASB Interpretation No. 46(R) (revised December 2003), Consolidation of Variable Interest Entities (VIEs) (FIN 46(R)), by evaluating the entity s design. FIN 46(R)-6 provides guidance regarding how contracts or arrangements that create or reduce variability should be considered when determining whether entities qualify as VIEs. This interpretation addresses consolidation by business enterprises of entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. Under FIN 46(R)-6, consolidation of a VIE by the primary beneficiary is required if it is determined that the VIE does not effectively disperse risks among the parties involved. The primary beneficiary is the party that has either a majority of the expected losses or a majority of the expected residual returns of such entity, as defined. The guidance of FIN 46(R)-6 must be applied on a prospective basis in reporting periods beginning after June 15, 2006, which would be our fourth fiscal quarter. The new requirements do not need to be applied to existing entities unless a reconsideration event occurs. We are currently evaluating the impact of adopting FIN 46(R)-6.

Recent Developments

In May 2006, the Internal Revenue Service began an audit of the Company s income tax return for the tax years ended October 31, 2003 and 2004. We are unable to predict the impact that the audit may have on our financial position or results of operations.

Forward-Looking Statements

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, including those that affect allowed rates of return, terms and conditions of service, rate structures and financings. We monitor our effectiveness in achieving the allowed rates of return and initiate rate proceedings or operating changes as needed. In addition, we purchase natural gas transportation and storage services from interstate and intrastate pipeline companies whose rates and services are regulated.

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

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

The potential loss of large-volume industrial customers to alternate fuels or to bypass, or the shift by such customers to special competitive contracts at lower per-unit margins.

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

The capital-intensive nature of our business. In order to maintain growth, we must add to our natural gas distribution system each year. The cost of this construction may be affected by the cost of obtaining governmental approvals, compliance with federal and state pipeline safety and integrity regulations, development project delays and changes in project costs. Weather, general economic conditions and the cost of funds to finance our capital projects can materially alter the cost of a project. Our internally generated cash flows are not adequate to finance the full cost of this construction. 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 availability and cost of natural gas. To meet firm customer requirements, we must acquire sufficient gas supplies and pipeline capacity to ensure delivery to our distribution system while also ensuring that our supply and capacity contracts allow us to remain competitive. Natural gas is an unregulated commodity market subject to supply and demand and price volatility. Producers, marketers and pipelines are subject to operating and financial risks associated with exploring, drilling, producing, gathering, marketing and transporting natural gas and have risks that increase our exposure to supply and price fluctuations.

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

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

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

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

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

All of these factors are difficult to predict and some 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, t of such words and similar expressions are intended to identify forward-looking statements.

Factors relating to regulation and management also may be described or incorporated by reference in future filings with the SEC. Some of the factors that may cause actual results to differ have been described above. Others may be described elsewhere in this report. There may also be other factors besides those described above that could cause actual conditions, events or results to differ from those in the 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 web site 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 web site as soon as reasonably practicable after the report is filed with or furnished to the SEC.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

We hold all financial instruments discussed in this item for purposes other than trading. We are potentially exposed to market risk due to changes in interest rates and the cost of gas. Our exposure to interest rate changes relates primarily to short-term debt. We are exposed to interest rate changes to long-term debt when we are in the market to issue long-term debt. As of April 30, 2006, all of our long-term debt was at fixed rates. Exposure to gas cost variations relates to the wholesale supply, demand and price of natural gas.

Interest Rate Risk

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

As of April 30, 2006, we had $252 million of short-term debt outstanding. A change of 100 basis points in the underlying interest rate for our short-term debt would have caused a change in interest expense of approximately $1.3 million during the six months ended April 30, 2006.

As of April 30, 2006, all of our long-term debt was at fixed interest rates and, therefore, not subject to interest rate risk.

Commodity Price Risk

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

Additional information concerning market risk is set forth in Financial Condition and Liquidity in

Management s Discussion and Analysis of Financial Condition and Results of Operations in Item 2 of this Form 10-Q.

Item 4. 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-Q. Based on such evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, as of the end of the period covered by this Form 10-Q, our disclosure controls and procedures were effective in that they provide reasonable assurances 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.

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 second quarter of fiscal 2006 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

In addition to the appeals to two NCUC orders filed by the North Carolina Office of the Attorney General discussed in Note 4 to the condensed consolidated financial statements, we have only routine litigation in the normal course of business. We do not expect the outcomes to such routine litigation to have any material impact on our financial position, results of operations or cash flows.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

c) Issuer Purchases of Equity Securities.

The following table provides information with respect to purchases of common stock under the Common Stock Open Market Purchase Program during the three months ended April 30, 2006.

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
Beginning of the period				8,386,474
February 2006	382,400	$23.96	382,400	8,004,074
March 2006	70,000	23.38	70,000	7,934,074
April 2006	1,203,000	23.91	1,203,000	6,731,074
Total	1,655,400	23.90	1,655,400	

The Common Stock Open Market Purchase Program was announced on June 4, 2004, to purchase up to three million shares of common stock for reissuance under our dividend reinvestment, stock purchase and incentive compensation plans. On December 16, 2005, the Board of Directors approved an increase in the number of shares in this program from three million to six million to reflect the two-for-one stock split in 2004. The Board also approved the purchase of up to four million additional shares of common stock and amended the program to provide for purchases 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. Included in the shares purchased in April 2006 are 1 million shares purchased under our ASR as described in Note 5 to the condensed consolidated financial statements.

The amount of cash dividends that may be paid is restricted by provisions contained in certain note agreements under which long-term debt was issued. As of April 30, 2006, none of our retained earnings was restricted.

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

We held our Annual Meeting of Shareholders on March 3, 2006, to elect three directors, to ratify the selection of our independent registered public accounting firm, to amend our Articles of Incorporation to increase the number of authorized shares and to approve the Incentive Compensation Plan effective as of November 1, 2005. The record date for determining the shareholders entitled to receive notice of and to vote at the meeting was January 10, 2006. We solicited proxies for the meeting according to section 14(a) of the Securities and Exchange Act of 1934. There was no solicitation in opposition to management s solicitations.

Shareholders elected all of the nominees for director as listed in the proxy statement by the following votes:

	Shares Voted FOR	Shares Voted WITHHELD	Shares NOT VOTED
For terms expiring in 2009:			
John W. Harris	63,467,254	2,514,304	10,631,127
Aubrey B. Harwell, Jr.	65,266,914	714,644	10,631,127
David E. Shi	65,267,043	714,515	10,631,127

The current terms of directors Jerry W. Amos, D. Hayes Clement and Thomas E. Skains will expire at our annual meeting in 2007. The current terms of directors Malcolm E. Everett III, Muriel W. Helms, Frank B. Holding, Jr., and Minor M. Shaw will expire at our annual meeting in 2008.

Shareholders ratified the selection by the Board of Directors of the firm of Deloitte & Touche LLP as our independent registered public accounting firm for the fiscal year ending October 31, 2006, by the following vote:

Shares Voted FOR	Shares Voted AGAINST	Shares Voted ABSTAINING	Broker Non-Votes	Shares NOT VOTED
65,123,220	584,617	273,721		10,631,127

Shareholders approved an amendment to Article 3 of our Articles of Incorporation to increase the number of authorized shares of common stock from 100 million to 200 million shares.

Shares Voted FOR	Shares Voted AGAINST	Shares Voted ABSTAINING	Broker Non-Votes	Shares NOT VOTED
61,288,917	4,078,458	614,167	16	10,631,127

Shareholders approved the Incentive Compensation Plan effective as of November 1, 2005.

Shares Voted FOR	Shares Voted AGAINST	Shares Voted ABSTAINING	Broker Non-Votes	Shares NOT VOTED
39,134,264	4,869,328	1,784,183	20,193,783	10,631,127

Item 6. Exhibits

3.1 Articles of Incorporation of the Company, as amended (Exhibit 4.1, Form S-8 Registration Statement No. 333-132738).

Exhibits 10.1 through 10.7 are management contracts or compensatory plans, contracts or arrangements.

10.1 Employment Agreement dated as of May 1, 2006, between Piedmont Natural Gas Company, Inc. and Michael H. Yount.

10.2 Employment Agreement dated as of May 1, 2006, between Piedmont Natural Gas Company, Inc. and Kevin M. O Hara.

10.3 Severance Agreement dated as of May 1, 2006, between Piedmont Natural Gas Company, Inc. and Michael H. Yount.

10.4 Severance Agreement dated as of May 1, 2006, between Piedmont Natural Gas Company, Inc. and Kevin M. O Hara.

10.5 Severance Agreement dated as of May 1, 2006, between Piedmont Natural Gas Company, Inc. and June B. Moore.

10.6 Severance Agreement dated as of May 1, 2006, between Piedmont Natural Gas Company, Inc. and Jane R. Lewis-Raymond.

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

31.1 Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 of the Chief Executive Officer.

31.2 Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 of the Chief Financial Officer.

32.1 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 of the Chief Executive Officer.

32.2 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 of the Chief Financial Officer.

SIGNATURES

Pursuant to the requirements of 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)

Date June 9, 2006

/s/ David J. Dzuricky

David J. Dzuricky
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Date June 9, 2006

/s/ Barry L. Guy

Barry L. Guy
Vice President and Controller
(Principal Accounting Officer)

Piedmont Natural Gas Company, Inc.
Form 10-Q
For the Quarter Ended April 30, 2006
Exhibits

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