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

FORM 10-Q

(Mark One)

[✓] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Quarterly Period Ended June 30, 2006

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 1-14174

AGL RESOURCES INC.

(Exact name of registrant as specified in its charter)

Georgia	**58-2210952**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

Ten Peachtree Place NE, Atlanta, Georgia 30309
(Address and zip code of principal executive offices)

404-584-4000
(Registrant's telephone number, including area code)

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 is a large accelerated filer, an accelerated filer, or a non-accelerated filer. (Check one):

Large accelerated filer [✓]   Accelerated filer [ ]   Non-accelerated filer [ ]

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

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

Class	Outstanding as of July 31, 2006
Common Stock, $5.00 Par Value	77,878,889

AGL RESOURCES INC.

Quarterly Report on Form 10-Q

For the Quarter Ended June 30, 2006

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PART I – Financial Information
Item 1. Financial Statements

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

In millions, except share data	June 30, 2006	December 31, 2005	June 30, 2005
Current assets			
Cash and cash equivalents	$37	$30	$45
Receivables (less allowance for uncollectible accounts of $21 at June 30, 2006, $15 at Dec. 31, 2005 and $18 at June 30, 2005)	584	1,220	565
Inventories	642	543	381
Unrecovered environmental remediation costs – current	30	31	24
Unrecovered pipeline replacement program costs – current	27	27	24
Energy marketing and risk management assets	96	103	48
Other	92	78	113
Total current assets	1,508	2,032	1,200
Property, plant and equipment			
Property, plant and equipment	4,876	4,791	4,665
Less accumulated depreciation	1,510	1,458	1,396
Property, plant and equipment-net	3,366	3,333	3,269
Deferred debits and other assets			
Goodwill	422	422	401
Unrecovered pipeline replacement program costs	259	276	333
Unrecovered environmental remediation costs	155	165	188
Other	80	85	116
Total deferred debits and other assets	916	948	1,038
Total assets	$5,790	$6,313	$5,507
Current liabilities			
Payables	$566	$1,039	$589
Short-term debt	455	522	172
Accrued expenses	108	105	95
Energy marketing and risk management liabilities	46	117	46
Accrued pipeline replacement program costs – current	32	30	41
Accrued environmental remediation costs – current	12	13	10
Other	131	133	203
Total current liabilities	1,350	1,959	1,156
Accumulated deferred income taxes	444	423	425
Long-term liabilities			
Accrued pipeline replacement program costs	217	235	277
Accumulated removal costs	159	156	154
Accrued pension obligations	92	88	89
Accrued environmental remediation costs	89	84	86
Accrued postretirement benefit costs	51	54	58
Other	149	162	152
Total long-term liabilities	757	779	816
Commitments and contingencies (Note 8)			
Minority interest	34	38	32
Capitalization			
Long-term debt	1,632	1,615	1,621
Common shareholders' equity, $5 par value; 750,000,000 shares authorized	1,573	1,499	1,457
Total capitalization	3,205	3,114	3,078
Total liabilities and capitalization	$5,790	$6,313	$5,507

See Notes to Condensed Consolidated Financial Statements (Unaudited).

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(UNAUDITED)

In millions, except per share amounts	Three months ended June 30, 2006	Three months ended June 30, 2005	Six months ended June 30, 2006	Six months ended June 30, 2005
Operating revenues	$436	$431	$1,480	$1,343
Operating expenses				
Cost of gas	219	209	874	781
Operation and maintenance	113	113	230	228
Depreciation and amortization	34	33	68	66
Taxes other than income	10	10	20	21
Total operating expenses	376	365	1,192	1,096
Operating income	60	66	288	247
Other income (expense)	-	1	(2)	2
Interest expense	(29)	(26)	(59)	(52)
Minority interest	-	(3)	(19)	(16)
Earnings before income taxes	31	38	208	181
Income taxes	12	14	79	69
Net income	$19	$24	$129	$112
Basic earnings per common share	$0.25	$0.31	$1.66	$1.45
Diluted earnings per common share	$0.25	$0.30	$1.65	$1.44
Cash dividends paid per common share	$0.37	$0.31	$0.74	$0.62
Weighted-average number of common shares outstanding				
Basic	77.7	77.1	77.8	77.0
Diluted	78.1	77.8	78.2	77.7

See Notes to Condensed Consolidated Financial Statements (Unaudited).

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME
(UNAUDITED)

In millions, except per share amount	Common Stock Shares	Common Stock Amount	Premium on common shares	Retained earnings	Accumulated other comprehensive income	Shares Held in Treasury	Total
Balance as of December 31, 2005	77.8	$389	$655	$508	$(53)	$-	$1,499
Comprehensive income:							
Net income	-	-	-	129	-	-	129
Unrealized gain from hedging activities (net of taxes of $2)	-	-	-	-	3	-	3
Total comprehensive income							132
Dividends on common shares ($0.74 per share)	-	-	-	(58)	-	-	(58)
Benefit, dividend reinvestment and share purchase plans	0.5	2	3	-	-	8	13
Purchase of treasury shares	(0.4)					(15)	(15)
Stock-based compensation expense (net of tax benefit of $1)	-	-	2	-	-	-	2
Balance as of June 30, 2006	77.9	$391	$660	$579	$(50)	$(7)	$1,573

See Notes to Condensed Consolidated Financial Statements (Unaudited).

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

In millions	Six months ended June 30, 2006	Six months ended June 30, 2005
Cash flows provided by (used in) operating activities		
Net income	$129	$112
Adjustments to reconcile net income to net cash flow provided by operating activities		
Depreciation and amortization	68	66
Minority interest	19	16
Deferred income taxes	21	(12)
Change in risk management assets and liabilities	(64)	12
Changes in certain assets and liabilities		
Receivables	636	324
Inventories	(99)	(49)
Payables	(473)	(139)
Other	-	15
Net cash flow provided by operating activities	237	345
Cash flows provided by (used in) investing activities		
Property, plant and equipment expenditures	(113)	(130)
Other	5	3
Net cash flow used in investing activities	(108)	(127)
Cash flows provided by (used in) financing activities		
Payment of notes payable to Trusts	(150)	-
Payments of short-term debt	(67)	(162)
Dividends paid on common shares	(58)	(48)
Distributions to minority interest	(22)	(19)
Purchase of treasury shares	(15)	-
Issuance of senior notes	175	-
Sale of treasury shares	8	-
Sale of common stock	7	7
Net cash flow used in financing activities	(122)	(222)
Net increase (decrease) in cash and cash equivalents	7	(4)
Cash and cash equivalents at beginning of period	30	49
Cash and cash equivalents at end of period	$37	$45
Cash paid during the period for		
Interest (net of allowance for funds used during construction)	$49	$39
Income taxes	$19	$23

See Notes to Condensed Consolidated Financial Statements (Unaudited).

AGL RESOURCES INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Note 1
Accounting Policies and Methods of Application

General

AGL Resources Inc. is an energy services holding company that conducts substantially all of its operations through its subsidiaries. Unless the context requires otherwise, references to “we,” “us,” “our” or the “company” are intended to mean consolidated AGL Resources Inc. and its subsidiaries (AGL Resources).

We have prepared the accompanying unaudited condensed consolidated financial statements under the rules of the Securities and Exchange Commission (SEC). Under such rules and regulations, we have condensed or omitted certain information and notes normally included in financial statements prepared in conformity with accounting principles generally accepted in the United States of America (GAAP). However, the condensed consolidated financial statements reflect all adjustments that are, in the opinion of management, necessary for a fair presentation of our financial results for the interim periods. You should read these condensed consolidated financial statements in conjunction with our consolidated financial statements and related notes included in our Annual Report on Form 10-K, as amended, for the year ended December 31, 2005, filed with the SEC on June 1, 2006.

Due to the seasonal nature of our business, our results of operations for the three and six months ended June 30, 2006 and 2005 and our financial position as of December 31, 2005 and June 30, 2006 and 2005 are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period.

Basis of Presentation

Our condensed consolidated financial statements include our accounts, the accounts of our majority-owned and controlled subsidiaries and the accounts of variable interest entities for which we are the primary beneficiary. All significant intercompany items have been eliminated in consolidation. Certain amounts from prior periods have been reclassified and revised to conform to the current period presentation. Specifically, $62 million of negative salvage previously presented at December 31, 2005 and June 30, 2005 in accumulated depreciation has been presented in accumulated removal costs for all balance sheet dates presented herein.

We currently own a noncontrolling 70% financial interest in SouthStar Energy Services LLC (SouthStar), and Piedmont Natural Gas Company (Piedmont) owns the remaining 30%. Our 70% interest is noncontrolling because all significant management decisions require approval by both owners.

We are the primary beneficiary of SouthStar’s activities and have determined that SouthStar is a variable interest entity as defined by Financial Accounting Standards Board (FASB) Interpretation No. 46, “Consolidation of Variable Interest Entities,” as revised in December 2003 (FIN 46R). We determined that SouthStar was a variable interest entity because our equal voting rights with Piedmont are not proportional to our economic obligation to absorb 75% of any losses or residual returns from SouthStar. In addition, SouthStar obtains substantially all its transportation capacity for delivery of natural gas through our wholly owned subsidiary, Atlanta Gas Light Company (Atlanta Gas Light).

Prior to our sale of our 50% interest in Saltville Gas Storage Company, LLC (Saltville) in August 2005, we used the equity method to account for and report our interest in Saltville. Saltville was a joint venture with Duke Energy Corporation to develop a high-deliverability natural gas storage facility in Saltville, Virginia. We used the equity method because we exercised significant influence over, but did not control, the entity and because we were not the primary beneficiary as defined by FIN 46R.

Inventories

Sequent Energy Management, L.P. (Sequent) and SouthStar Energy Services LLC (SouthStar) subsidiaries account for their inventories at the lower of weighted average cost or market. Sequent and SouthStar evaluate the average cost of their natural gas inventories against market prices and determine whether any declines in market prices below the average cost are other than temporary.

For any declines considered to be other than temporary, adjustments are recorded to reduce the weighted average cost of the gas inventory to market.

Consequently, as a result of declining natural gas prices Sequent recorded adjustments of $8 million for the three months and $13 million for the six months ended June 30, 2006 against its cost of sales to reduce the value of its inventory. Sequent was not required to make similar adjustments in the same periods last year.

Comprehensive Income

Our comprehensive income includes net income plus other comprehensive income (OCI), which includes other gains and losses affecting shareholders' equity that GAAP excludes from net income. Such items consist primarily of unrealized gains and losses on certain derivatives designated as cash flow hedges. The following tables illustrate our OCI activity for the three and six months ended June 30, 2006 and 2005.

In millions	Three months ended June 30, 2006	2005
Cash flow hedges (1):		
Net derivative unrealized losses arising during the period (net of taxes of $0 in 2006 and $0 in 2005)	$ (1)	$ (1)
Less reclassification of realized losses included in income (net of taxes of $1 in 2006 and $0 in 2005)	2	-
Total	$ 1	$ (1)

In millions	Six months ended June 30, 2006	2005
Cash flow hedges (1):		
Net derivative unrealized gains arising during the period (net of taxes of $4 in 2006 and $0 in 2005)	$ 6	$ 1
Less reclassification of realized gains included in income (net of taxes of $2 in 2006 and $3 in 2005)	(3)	(5)
Total	$ 3	$ (4)

(1) Taxes of $0 represent taxes that round to less than $1 million.

Earnings per Common Share

We compute basic earnings per common share by dividing our income available to common shareholders by the weighted-average number of common shares outstanding daily. Diluted earnings per common share reflect the potential reduction in earnings per common share that could occur when potential dilutive common shares are added to common shares outstanding.

We derive our potential dilutive common shares by calculating the number of shares issuable under restricted stock, restricted share units and stock options. The future issuance of shares underlying the restricted stock and restricted share units depends on the satisfaction of certain performance criteria. The future issuance of shares underlying the outstanding stock options depends upon whether the exercise prices of the stock options are less than the average market price of the common shares for the respective periods. The following table shows the calculation of our diluted shares, assuming restricted stock and restricted stock units currently awarded under the plan ultimately vest and stock options currently exercisable at prices below the average market prices are exercised.

In millions	Three months ended June 30, 2006	2005
Denominator for basic earnings per share (1)	77.7	77.1
Assumed exercise of restricted stock, restricted stock units and stock options	0.4	0.7
Denominator for diluted earnings per share	78.1	77.8

(1) Daily weighted-average shares outstanding

In millions	Six months ended June 30, 2006	2005
Denominator for basic earnings per share (1)	77.8	77.0
Assumed exercise of restricted stock, restricted stock units and stock options	0.4	0.7
Denominator for diluted earnings per share	78.2	77.7

(1) Daily weighted-average shares outstanding

Recent Accounting Pronouncements

Issued but not yet adopted In July 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. (FIN) 48, "Accounting for Uncertainty in Income Taxes - an Interpretation of Statement of Financial Accounting Standards No. 109" (FIN 48).

FIN 48 is applicable to all uncertain positions for taxes accounted for under Statement of Financial Accounting Standards (SFAS) No. 109, "Accounting for Income Taxes," (SFAS 109), and is not intended to be applied by analogy to other taxes, such as sales taxes, value-add taxes, or property taxes.

The scope of FIN 48 includes any position taken (or expected to be taken) on a tax return, including the decision to exclude from the return certain income or transactions. FIN 48 applies to positions such as (1) excluding income streams that might be deemed taxable by the taxing authorities, (2) asserting that a particular equity restructuring (e.g., a spin-off transaction) is tax-free when that position might be uncertain, or (3) the decision not to file a tax return in a particular jurisdiction for which such a return might be required.

FIN 48 requires that we make qualitative and quantitative disclosures, including discussion of reasonably possible changes that might occur in the recognized tax benefits over the next 12 months; a description of open tax years by major jurisdictions; and a roll-forward of all unrecognized tax benefits, presented as a reconciliation of the beginning and ending balances of the unrecognized tax benefits on a aggregated basis. FIN 48 is effective January 1, 2007 and would require us to record any change in net assets that results from the adoption of FIN 48 as an adjustment to the opening balance of retained earnings. We are evaluating the impact that the adoption of FIN 48 will have on our consolidated results of operations, cash flows and financial position.

Note 2
Risk Management

Our risk management activities are monitored by our Risk Management Committee (RMC). The RMC consists of members of senior management and is charged with reviewing our risk management activities and overseeing enforcement of our risk management policies. Our risk management policies limit the use of derivative financial instruments and physical transactions within predefined risk tolerances associated with pre-existing or anticipated physical natural gas sales and purchases and system use and storage. We use the following derivative financial instruments and physical transactions to manage commodity price risks:

- forward contracts
- futures contracts
- options contracts
- financial swaps
- storage and transportation capacity transactions

There have been no significant changes to our risk management activities, as described in Note 4 to our Consolidated Financial Statements in Item 8 of our Annual Report on Form 10-K, as amended, for the year ended December 31, 2005.

Note 3
Regulatory Assets and Liabilities

We have recorded regulatory assets and liabilities in our consolidated balance sheets in accordance with SFAS No. 71, “Accounting for the Effects of Certain Types of Regulation.” There have been no significant changes to our regulatory assets and liabilities since December 31, 2005, which was described in Note 5 to our Consolidated Financial Statements in Item 8 of our Annual Report on Form 10-K, as amended, for the year ended December 31, 2005. Our regulatory assets and liabilities, and associated liabilities for our unrecovered pipeline replacement program (PRP) costs and unrecovered environmental remediation costs (ERC), are summarized in the table below:

In millions	June 30, 2006	Dec. 31, 2005	June 30, 2005
Regulatory assets			
Unrecovered PRP costs	$286	$303	$357
Unrecovered ERC	185	196	212
Unrecovered postretirement benefit costs	13	14	14
Unrecovered seasonal rates	-	11	-
Energy marketing and risk management activities	9	17	9
Unrecovered purchased gas adjustment	1	8	2
Other	10	10	7
Total regulatory assets	$504	$559	$601
Regulatory liabilities			
Accumulated removal costs	$159	$156	$154
Deferred purchased gas adjustment	19	40	57
Deferred seasonal rates	9	-	9
Unamortized investment tax credit	18	19	20
Regulatory tax liability	15	15	11
Energy marketing and risk management	9	17	9
Other	5	6	-
Total regulatory liabilities	234	253	260
Associated liabilities			
PRP costs	249	265	318
ERC	101	97	96
Total associated liabilities	350	362	414
Total regulatory and associated liabilities	$584	$615	$674

Note 4
Employee Benefit Plans

Pension Benefits We sponsor two tax qualified defined benefit retirement plans for our eligible employees: the AGL Resources Inc. Retirement Plan and the NUI Corporation Retirement Plan. A defined benefit plan specifies the amount of benefits an eligible participant eventually will receive using information about the participant. The following are the combined cost components of our two pension plans for the periods indicated:

	Three months ended June 30,	
In millions	2006	2005
Service cost	$2	$2
Interest cost	6	6
Expected return on plan assets	(8)	(8)
Net amortization	-	-
Recognized actuarial loss	2	2
Net cost	$2	$2

	Six months ended June 30,	
In millions	2006	2005
Service cost	$4	$5
Interest cost	13	13
Expected return on plan assets	(16)	(16)
Net amortization	(1)	(1)
Recognized actuarial loss	4	3
Net cost	$4	$4

Our employees do not contribute to the retirement plans. We fund the plans by contributing at least the minimum amount required by applicable regulations and as recommended by our actuary. However, we may also contribute in excess of the minimum required amount. We calculate the minimum amount of funding using the projected unit credit cost method. We are not required to make any contribution to our pension plans in 2006.

Postretirement Benefits We sponsor two defined benefit postretirement health care plans for our eligible employees: the AGL Resources Inc. Postretirement Health Care Plan and the NUI Corporation Postretirement Health Care Plan. Eligibility for these benefits is based on age and years of service. The following are the combined cost components of these two postretirement benefit plans for the periods indicated:

	Three months ended June 30,	
In millions	2006	2005
Service cost	$-	$-
Interest cost	2	2
Expected return on plan assets	(1)	(1)
Prior service cost	(1)	(1)
Recognized actuarial loss	-	1
Net cost	$-	$1

	Six months ended June 30,	
In millions	2006	2005
Service cost	$-	$1
Interest cost	3	3
Expected return on plan assets	(2)	(2)
Prior service cost	(2)	(2)
Recognized actuarial loss	1	1
Net cost	$-	$1

Note 5
Stock-based Compensation Plans

Effective January 1, 2006, we adopted SFAS No. 123(R), “Share-Based Payment” (SFAS 123R), using the modified prospective application transition method; accordingly, financial results for the prior periods presented were not retroactively adjusted to reflect the effects of SFAS 123R.

Prior to January 1, 2006, we accounted for our share-based payment transactions in accordance with SFAS 123, as amended by SFAS No. 148, “Accounting for Stock-Based Compensation-Transition and Disclosure,” which allowed us to follow Accounting Principles Board (APB) Opinion No. 25, “Accounting for Stock Issued to Employees” (APB 25) and related interpretations in accounting for our stock-based compensation plans.

SFAS 123R requires us to measure and recognize stock-based compensation expense in our financial statements based on the estimated fair value at the date of grant for our share-based awards, which include performance shares and stock options. Performance share awards contain market conditions; both performance share and stock option awards contain a service condition. In accordance with SFAS 123R, we recognize compensation expense over the requisite service period for:

- awards granted on or after January 1, 2006; and

- unvested awards previously granted and outstanding as of January 1, 2006.

In addition, we estimate forfeitures over the requisite service period when recognizing compensation expense; these estimates are adjusted to the extent that actual forfeitures differ, or are expected to materially differ, from such estimates. Our net income for the three months ended June 30, 2006 includes $3 million of compensation costs and $1 million of income tax benefits related to our compensation awards. Our net income for the six months ended June 30, 2006 includes $5 million of compensation costs and $1 million of income tax benefits related to our compensation awards.

In 2005 we did not record compensation expense related to our stock option grants in our financial statements in accordance with APB 25. However, at the end of each reporting period, we recorded compensation expense over the requisite service period for our other stock-based and cash unit awards. Our net income for the three months ended June 30, 2005 includes $3 million of compensation costs and $1 million of income tax benefits related to those performance shares. Our net income for the six months ended June 30, 2005 includes $4 million of compensation costs and $3 million of income tax benefits related to those performance shares.

Prior to our adoption of SFAS 123R, benefits of tax deductions in excess of recognized compensation costs were reported as operating cash flows. SFAS 123R requires excess tax benefits to be reported as a financing cash inflow rather than as a reduction of taxes paid. For the six months ended June 30, 2006, our cash flow used in financing activities included an immaterial amount for benefits of tax deductions in excess of recognized compensation costs. For the same period last year, $3 million of such benefits was included in cash flow provided by operating activities.

If stock-based compensation expense for the three and six months ended June 30, 2005 had been recorded based on the fair value of the awards at the grant dates consistent with the method prescribed by SFAS 123, which was superseded by SFAS 123R, our net income and earnings per share for the three and six months ended June 30, 2005 would have been reduced to the amounts shown in the following table:

In millions, except per share amounts	Three months ended June 30, 2005
Net income, as reported	$24
Deduct: Total stock-based employee compensation expense determined under fair value-based method for all awards, net of related tax effect	(1)
Pro-forma net income	$23
Earnings per share:	
Basic – as reported	$0.31
Basic – pro-forma	$0.30
Diluted – as reported	$0.30
Diluted – pro-forma	$0.30

In millions, except per share amounts	Six months ended June 30, 2005
Net income, as reported	$112
Deduct: Total stock-based employee compensation expense determined under fair value-based method for all awards, net of related tax effect	(1)
Pro-forma net income	$111
Earnings per share:	
Basic – as reported	$1.45
Basic – pro-forma	$1.45
Diluted – as reported	$1.44
Diluted – pro-forma	$1.43

Incentive and Nonqualified Stock Options

We grant incentive and nonqualified stock options at the fair market value on the date of the grant. Stock options generally have a three-year vesting period. As of June 30, 2006, our Board of Directors had authorized 10 million shares to be granted as stock options. The vesting of incentive options is subject to a statutory limitation of $100,000 per year under Section 422 of the Internal Revenue Code. Nonqualified options generally become fully exercisable not earlier than six months after the date of grant and generally expire 10 years after the date of grant. Participants realize value from option grants only to the extent that the fair market value of our common stock on the date of exercise of the option exceeds the fair market value of the common stock on the date of the grant. Compensation expense associated with stock options generally is recorded over the option vesting period; however, for unvested options that are granted to employees who are retirement eligible, the remaining compensation expense is recorded in the current period rather than over the remaining vesting period.

As of June 30, 2006, we had $5 million of total unrecognized compensation costs related to stock options. These costs are expected to be recognized over the remaining average vesting period of approximately 2.2 years. Cash received from stock option exercises for the six months ended June 30, 2006 was $7 million, and the income tax benefit from stock option exercises was $1 million. The following table summarizes activity during the six months ended June 30, 2006 related to grants of stock options for key employees and nonemployee directors.

Stock Options

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Life (in years)	Aggregate Intrinsic Value (in millions)
Outstanding – December 31, 2005	2,221,245	$27.79	6.8	$23
Granted	903,752	35.79	9.6	
Exercised	(269,920)	25.07	5.5	
Forfeited	(209,853)	34.93	8.8	
Outstanding – June 30, 2006	2,645,224	$30.24	7.6	$21
Exercisable – June 30, 2006	1,257,148	$25.02	5.6	$17

Unvested Stock Options

	Number of Unvested Options	Weighted Average Exercise Price	Weighted Average Remaining Vesting Period (in years)	Weighted Average Fair Value
Outstanding – December 31, 2005	945,556	$33.64	1.6	$4.72
Granted	903,752	35.79	2.6	4.79
Forfeited	(200,534)	34.99	2.6	5.03
Vested	(260,698)	32.93	-	4.54
Outstanding – June 30, 2006	1,388,076	$34.97	2.2	$4.75

In accordance with the fair value method of determining compensation expense, we use the Black-Scholes option pricing model. Following is the per share value and information about the underlying assumptions used in developing the grant date value for each of the grants made during the three months ended June 30, 2006 and 2005.

	Three months ended June 30, 2006	Three months ended June 30, 2005
Expected life (years)	7	7
Risk-free interest rate (1)	5.0%	3.9%
Expected volatility (2)	15.5%	17.3%
Dividend yield	4.1%	3.5%
Fair value of options granted (3)	$5.18	$5.56

(1) US Treasury constant maturity – 7 years
(2) Volatility is measured over 7 years, the expected life of the options
(3) Represents per share value.

Intrinsic value for options is defined as the difference between the current market value and the grant price. Total intrinsic value of options exercised during the six month period ended June 30, 2005 and 2006 were $7 million and $4 million respectively. The company uses treasury shares purchased under the company's share repurchase program to satisfy share-based exercises to the extent that treasury shares are available. Otherwise, shares are issued out of our common stock.

Stock and Restricted Stock Awards

Stock Awards Under the 1996 Non-Employee Directors Equity Compensation Plan (Directors Plan), each nonemployee director receives an annual retainer. The amount and form of the annual retainer is fixed by resolution of the Board of Directors. Effective in January 2006, the annual retainer was increased from $60,000 to $90,000, of which (1) $30,000 is payable in cash or, at the election of each director, in shares of our common stock or is deferred and invested in common stock equivalents under the 1998 Common Stock Equivalent Plan for Non-Employee Directors (CSE Plan) and (2) $60,000 is payable, at the election of each director, in shares of our common stock or deferred under the CSE Plan. Upon initial election to our Board of Directors, each nonemployee director receives 1,000 shares of common stock as of the first day of his or her service. Shares issued under the Directors Plan are 100% vested and nonforfeitable as of the date of grant.

Restricted Stock Awards In general, we refer to an award of our common stock that is subject to time-based vesting or achievement of performance measures as "restricted stock." Restricted stock awards are subject to certain transfer restrictions and forfeiture upon termination of employment. In March 2006 we granted to a select group of executive officers a total of 40,000 shares of our restricted stock. The following table summarizes activity during the six months ended June 30, 2006
related to restricted stock awards for our key employees.

Restricted Stock Awards	Shares of Restricted Stock	Weighted Average Remaining Vesting Period (in years)	Weighted Average Fair Value
Outstanding – December 31, 2005	120,728	1.8	$34.33
Issued	192,945	2.7	35.63
Forfeited	(18,366)	2.6	33.62
Vested	(25,831)	-	34.47
Outstanding – June 30, 2006 (1)	269,476	2.4	$35.30

Performance Units

A performance unit is an award of the right to receive either (1) shares of company common stock or (2) cash, subject to the achievement of certain pre-established performance criteria. Performance units are subject to certain transfer restrictions and forfeiture upon termination of employment. In the first quarter of 2006, we granted restricted stock units and performance cash units to a select group of officers as described below.

Restricted Stock Units A restricted stock unit is an award that represents the opportunity to receive a specified number of shares of our common stock, subject to the achievement of certain pre-established performance criteria.

In February 2006, we granted to a select group of officers a total of 64,700 restricted stock units under the Long-Term Incentive Plan (1999) (LTIP), all of which were outstanding as of June 30, 2006. These restricted stock units have a 12-month performance measurement period.

Performance Cash Units A performance cash unit is an award that represents the opportunity to receive a cash award, subject to the achievement of certain pre-established performance criteria.

In January 2006, we granted performance cash units to a select group of officers under the LTIP. The performance cash units represent a maximum aggregate payout of $2 million. The performance cash units have a 36-month performance measurement period and a performance measure that relates to our average annual growth in basic earnings per share plus the average dividend yield. As of June 30, 2006 we had recorded a liability of less than $1 million for these performance cash units.

Stock Appreciation Rights (SARs)

SARs are awards payable in cash, having an exercise price equal to the fair market value of our common stock on the date of grant. SARs generally become fully exercisable not earlier than 12 months after the date of grant and generally expire six years after that date. Participants realize value from SAR grants only to the extent that the fair market value of our common stock on the date of exercise of the SAR exceeds the fair market value of the common stock on the date of the grant. At June 30, 2006, we had approximately 27,000 SARs outstanding.

Note 6
Common Shareholders' Equity

Share Repurchase Program

In February 2006, our Board of Directors authorized a plan to purchase up to 8 million shares of our outstanding common stock over a five-year period. These purchases are intended principally to offset share issuances under our employee and nonemployee director incentive compensation plans and our dividend reinvestment and stock purchase plans. Stock purchases under this program may be made in the open market or in private transactions at times and in amounts that we deem appropriate. There is no guarantee as to the exact number of shares that we may purchase, and we may terminate or limit the program at any time. We will hold the purchased shares as treasury shares. During the six months ended June 30, 2006, we repurchased 417,250 shares at a weighted average price of $35.74.

Note 7
Debt

Our issuance of long-term and short-term debt, including various forms of securities, is subject to customary approval or authorization by state and federal regulatory bodies, including state public service commissions and the SEC. Our financing consists of the short and long-term debt indicated in the following table.

			Outstanding as of:		
Dollars in millions	Year(s) due	Int. rate (1)	June 30, 2006	Dec. 31, 2005	June 30, 2005
Short-term debt					
Commercial paper	2006	5.4% (2)	$438	$485	$156
Sequent lines of credit	2006 - 2007	5.4 - 5.6% (3)	3	-	15
Pivotal Utility line of credit	2006	5.7% (4)	13	-	-
Capital leases	2006	4.9	1	1	1
SouthStar line of credit	2006	-	-	36	-
Total short-term debt		**5.4%** (5)	**$455**	**$522**	**$172**
Long-term debt - net of current portion					
Senior notes	2011-2034	4.5 - 7.1%	$1,150	$975	$975
Medium-term notes	2012-2027	6.6 - 9.1	208	208	208
Gas facility revenue bonds, net of unamortized issuance costs	2022-2033	3.3 – 5.7	199	199	199
Notes payable to Trusts	2037	8.2	77	232	232
Capital leases	2013	4.9	6	6	7
Interest rate swaps	2011	8.1	(8)	(5)	-
Total long-term debt		**6.1%** (5)	**$1,632**	**$1,615**	**$1,621**
Total short-term and long-term debt		**5.9%** (5)	**$2,087**	**$2,137**	**$1,793**

(1) As of June 30, 2006.
(2) The daily weighted average rate was 4.8% for the six months ended June 30, 2006.
(3) The daily weighted average rate was 5.3% for the six months ended June 30, 2006. This line of credit was extended until June 30, 2007.
(4) The daily weighted average rate was 5.3% for the six months ended June 30, 2006.
(5) Weighted average interest rate, including interest rate swaps if applicable and excluding debt issuance and other financing related costs.

Long-term debt In May 2001, AGL Capital Trust II (Trust) issued and sold $150 million of 8.00% capital securities and used the proceeds to purchase $150 million principal amount of 8.00% junior subordinated deferrable interest debentures from us. In May 2006, we used the proceeds from the sale of commercial paper to redeem the $150 million of junior subordinated debentures and to pay a $5 million note representing our investment in the Trust, previously included in notes payable to Trusts. In June 2006, we issued $175 million of 10-year senior notes at an interest rate of 6.375% and used the net proceeds of $174 million to repay the commercial paper.

In the third quarter of 2005 and the second quarter of 2006, in anticipation of our $175 million senior notes offering in June 2006, we entered into treasury lock derivative agreements to hedge our exposure to increases in interest rates. We received an $11 million settlement payment from our counterparties, which we will amortize over the next 10 years through interest expense. These derivatives reduced the annual interest rate on our 6.375% senior notes by approximately 60 basis points.

Note 8
Commitments and Contingencies

Contractual Obligations and Commitments We have incurred various contractual obligations and financial commitments in the normal course of our operations and financing activities. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements. These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related revenue-producing activities. There were no significant changes to our contractual obligations which were described in Note 10 to our Consolidated Financial Statements in Item 8 of our Annual Report on Form 10-K, as amended, for the year ended December 31, 2005.

We also have incurred various financial commitments in the normal course of business. Contingent financial commitments represent obligations that become payable only if certain predefined events occur, such as financial guarantees, and include the nature of the guarantee and the maximum potential amount of future payments that could be required of us as the guarantor. The following table illustrates our contingent financial commitments as of June 30, 2006.

		Commitments due before Dec. 31,	
In millions	Total	2006	2007 & thereafter
Standby letters of credit and performance and surety bonds	$21	$11	$10

Litigation We are involved in litigation arising in the normal course of business. There has been no significant change in the litigation which was described in Note 10 to our Consolidated Financial Statements in Item 8 of our Annual Report on Form 10-K, as amended, for the year ended December 31, 2005. We believe the ultimate resolution of such litigation will not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Note 9
Segment Information

Our four operating segments are:

- Distribution operations, which consists primarily of:
    - Atlanta Gas Light
    - Elizabethtown Gas
    - Virginia Natural Gas
    - Florida City Gas
    - Chattanooga Gas
    - Elkton Gas
- Retail energy operations, which consists of SouthStar
- Wholesale services, which consists primarily of Sequent
- Energy investments, which consists primarily of:
    - Pivotal Jefferson Island
    - Pivotal Propane
    - AGL Networks

We treat corporate, our fifth segment, as a non-operating business segment, and it includes AGL Resources Inc., AGL Services Company, investments in nonregulated financing subsidiaries and the effect of intersegment eliminations. We eliminated intersegment sales for the three and six months ended June 30, 2006 and 2005 from our condensed consolidated statements of income.

We evaluate segment performance based primarily on the non-GAAP measure of earnings before interest and taxes (EBIT), which includes the effects of corporate expense allocations. EBIT is a non-GAAP measure that includes operating income, other income and minority interest. Items that we do not include in EBIT are financing costs, including interest and debt expense and income taxes, each of which we evaluate on a consolidated level. We believe EBIT is a useful measurement of our performance because it provides information that can be used to evaluate the effectiveness of our businesses from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which we believe is directly relevant to the efficiency of those operations.

You should not consider EBIT an alternative to, or a more meaningful indicator of, our operating performance than operating income or net income as determined in accordance with GAAP. In addition, our EBIT may not be comparable to a similarly titled measure of another company. The reconciliations of EBIT to operating income and net income for the three and six months ended June 30, 2006 and 2005 are presented below.

	Three months ended June 30,	
In millions	2006	2005
Operating revenues	$436	$431
Operating expenses	376	365
Operating income	60	66
Other income	-	1
Minority interest	-	(3)
EBIT	60	64
Interest expense	29	26
Earnings before income taxes	31	38
Income taxes	12	14
Net income	$19	$24

	Six months ended June 30,	
In millions	2006	2005
Operating revenues	$1,480	$1,343
Operating expenses	1,192	1,096
Operating income	288	247
Other income	(2)	2
Minority interest	(19)	(16)
EBIT	267	233
Interest expense	59	52
Earnings before income taxes	208	181
Income taxes	79	69
Net income	$129	$112

Summarized income statement information and property, plant and equipment expenditures as of and for the three and six months ended June 30, 2006 and 2005 by segment are shown in the following tables:

Three months ended June 30, 2006

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intersegment eliminations	Consolidated AGL Resources
Operating revenues from external parties	$254	$153	$19	$10	$-	$436
Intersegment revenues (1)	39	-	-	-	(39)	-
Total operating revenues	293	153	19	10	(39)	436
Operating expenses						
Cost of gas	113	136	8	2	(40)	219
Operation and maintenance	84	16	9	4	-	113
Depreciation and amortization	29	1	1	1	2	34
Taxes other than income taxes	9	-	-	1	-	10
Total operating expenses	235	153	18	8	(38)	376
Operating income (loss)	58	-	1	2	(1)	60
Other income (expense)	1	-	-	-	(1)	-
Minority interest	-	-	-	-	-	-
EBIT	$59	$-	$1	$2	$(2)	$60
Property, plant and equipment expenditures	$45	$2	$-	$6	$13	$66

Three months ended June 30, 2005

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intersegment eliminations	Consolidated AGL Resources
Operating revenues from external parties	$245	$160	$9	$17	$-	$431
Intersegment revenues (1)	48	-	-	-	(48)	-
Total operating revenues	293	160	9	17	(48)	431
Operating expenses						
Cost of gas	114	136	-	5	(46)	209
Operation and maintenance	91	14	6	5	(3)	113
Depreciation and amortization	29	1	1	1	1	33
Taxes other than income taxes	8	-	-	1	1	10
Total operating expenses	242	151	7	12	(47)	365
Operating income (loss)	51	9	2	5	(1)	66
Other income	1	-	-	-	-	1
Minority interest	-	(3)	-	-	-	(3)
EBIT	$52	$6	$2	$5	$(1)	$64
Property, plant and equipment expenditures	$37	$1	$-	$3	$6	$47

(1) Wholesale services total operating revenues include intersegment revenues of $118 million and $162 million for the three months ending June 30, 2006 and 2005, respectively.

Six months ended June 30, 2006

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intersegment eliminations	Consolidated AGL Resources
Operating revenues from external parties	$850	$543	$67	$20	$-	$1,480
Intersegment revenues (1)	83	-	-	-	(83)	-
Total operating revenues	933	543	67	20	(83)	1,480
Operating expenses						
Cost of gas	508	432	13	4	(83)	874
Operation and maintenance	169	34	20	9	(2)	230
Depreciation and amortization	58	2	1	2	5	68
Taxes other than income taxes	17	-	-	1	2	20
Total operating expenses	752	468	34	16	(78)	1,192
Operating income (loss)	181	75	33	4	(5)	288
Other income (expense)	1	(2)	-	-	(1)	(2)
Minority interest	-	(19)	-	-	-	(19)
EBIT	$182	$54	$33	$4	$(6)	$267
Property, plant and equipment expenditures	$78	$3	$1	$7	$24	$113

Six months ended June 30, 2005

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intersegment eliminations	Consolidated AGL Resources
Operating revenues from external parties	$820	$474	$20	$29	$-	$1,343
Intersegment revenues (1)	107	-	-	-	(107)	-
Total operating revenues	927	474	20	29	(107)	1,343
Operating expenses						
Cost of gas	495	384	-	8	(106)	781
Operation and maintenance	184	27	13	8	(4)	228
Depreciation and amortization	57	1	1	3	4	66
Taxes other than income taxes	17	-	-	1	3	21
Total operating expenses	753	412	14	20	(103)	1,096
Operating income (loss)	174	62	6	9	(4)	247
Other income	1	-	-	1	-	2
Minority interest	-	(16)	-	-	-	(16)
EBIT	$175	$46	$6	$10	$(4)	$233
Property, plant and equipment expenditures	$109	$1	$2	$6	$12	$130

(1) Wholesale services total operating revenues include intersegment revenues of $294 million and $249 million for the six months ending June 30, 2006 and 2005, respectively.

Balance sheet information at June 30, 2006 and 2005 and December 31, 2005 by segment is shown in the following tables:

As of June 30, 2006

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intersegment eliminations (2)	Consolidated AGL Resources
Goodwill	$408	$-	$-	$14	$-	$422
Identifiable and total assets (1)	$4,457	$190	$814	$333	$(4)	$5,790

As of December 31, 2005

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intersegment eliminations (2)	Consolidated AGL Resources
Goodwill	$408	$-	$-	$14	$-	$422
Identifiable and total assets (1)	$4,782	$342	$1,058	$350	$(219)	$6,313

As of June 30, 2005

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intersegment eliminations (2)	Consolidated AGL Resources
Goodwill	$387	$-	$-	$14	$-	$401
Identifiable assets (1)	$4,647	$169	$653	$319	$(321)	$5,467
Investment in joint ventures	35	-	-	28	(23)	40
Total assets	$4,682	$169	$653	$347	$(344)	$5,507

(1) Identifiable assets are those assets used in each segment's operations.
(2) Our corporate segment's assets consist primarily of intersegment eliminations, cash and cash equivalents and property, plant and equipment.

Note 10
Subsequent Event

On July 24, 2006, the Virginia State Corporation Commission (Virginia Commission) issued its order approving Virginia Natural Gas' performance-based rate (PBR) plan with modifications. These modifications, which were made by the Virginia Commission, include a requirement to construct and report on the progress of a pipeline connecting Virginia Natural Gas' northern and southern systems and reporting requirements to monitor compliance with the terms of the PBR plan. The estimated cost to construct the pipeline is $48-$60 million. Virginia Natural Gas has 30 days from the date of the order to accept the terms of the PBR plan as modified by the Virginia Commission. If Virginia Natural Gas does not accept the terms of the PBR plan as modified, the Virginia Commission's order requires that Virginia Natural Gas' rates be reduced by approximately $10 million effective July 24, 2006. If Virginia Natural Gas accepts the Virginia Commission's order, the PBR plan, as modified, will be effective August 1, 2006 with base rates frozen at current levels for five years.

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

FORWARD-LOOKING STATEMENTS

Certain expectations and projections regarding our future performance referenced in this Management's Discussion and Analysis of Financial Condition and Results of Operations section and elsewhere in this report, as well as in other reports and proxy statements we file with the Securities and Exchange Commission (SEC), are forward-looking statements. Officers and other employees may also make verbal statements to analysts, investors, regulators, the media and others that are forward-looking.

Forward-looking statements involve matters that are not historical facts, and because these statements involve anticipated events or conditions, forward-looking statements often include words such as "anticipate," "assume," "can," "could," "estimate," "expect," "forecast," "future," "indicate," "intend," "may," "outlook," "plan," "predict," "project," "seek," "should," "target," "will," "would," or similar expressions. Our expectations are not guarantees and are based on currently available competitive, financial and economic data along with our operating plans. While we believe that our expectations are reasonable in view of the currently available information, our expectations are subject to future events, risks and uncertainties, and there are several factors - many beyond our control - that could cause our results to differ significantly from our expectations.

Such events, risks and uncertainties include, but are not limited to, changes in price, supply and demand for natural gas and related products; the impact of changes in state and federal legislation and regulation; actions taken by government agencies on rates and other matters; concentration of credit risk; utility and energy industry consolidation; the impact of acquisitions and divestitures; direct or indirect effects on our business, financial condition or liquidity resulting from a change in our credit ratings or the credit ratings of our counterparties or competitors; interest rate fluctuations; financial market conditions and general economic conditions; uncertainties about environmental issues and the related impact of such issues; the impact of changes in weather on the temperature-sensitive portions of our business; the impact of natural disasters such as hurricanes on the supply and price of natural gas; acts of war or terrorism; and other factors that are described in detail in our filings with the SEC.

We caution readers that, in addition to the important factors described elsewhere in this report, the factors set forth in "Risk Factors" in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" of our Annual Report on Form 10-K, as amended for the year ended December 31, 2005, among others, could cause our business, results of operations or financial condition in 2006 and thereafter to differ significantly from those expressed in any forward-looking statements. There also may be other factors that we cannot anticipate or that are not described in our Form 10-K, as amended or in this report that could cause results to differ significantly from our expectations.

Forward-looking statements are only as of the date they are made, and we do not update these statements to reflect subsequent circumstances or events.

Overview

We are a Fortune 1000 energy services holding company whose principal business is the distribution of natural gas in six states - Florida, Georgia, Maryland, New Jersey, Tennessee and Virginia. Our six utilities serve approximately 2.3 million end-use customers, making us the largest distributor of natural gas in the southeastern and mid-Atlantic regions of the United States based on customer count. We also are involved in various related businesses, including retail natural gas marketing to end-use customers primarily in Georgia; natural gas asset management and related logistics activities for our own utilities as well as for other nonaffiliated companies; natural gas storage and related arbitrage activities; operation of high-deliverability underground natural gas storage assets; and construction and operation of telecommunications conduit and fiber infrastructure within selected metropolitan areas. We manage these businesses through four operating segments – distribution operations, retail energy operations, wholesale services and energy investments – and a nonoperating corporate segment.

The distribution operations segment is the largest component of our business and is regulated by regulatory agencies in six states. These agencies approve rates designed to provide us the opportunity to generate revenues to recover the cost of natural gas delivered to our customers and our fixed and variable costs such as depreciation, interest, maintenance and overhead costs, and to earn a reasonable return for our shareholders. With the exception of Atlanta Gas Light Company (Atlanta Gas Light), our largest utility, the earnings of our regulated utilities are weather sensitive to varying degrees. Although various regulatory mechanisms provide us a reasonable opportunity to recover our fixed costs regardless of natural gas volumes sold, the effect of weather manifests itself in terms of higher earnings during periods of colder weather and lower earnings in warmer weather. Atlanta Gas Light charges rates to its customers primarily on monthly fixed charges. Our retail energy operations segment, which consists of SouthStar, also is weather sensitive and uses a variety of hedging strategies to mitigate potential weather impacts. Our Sequent subsidiary within our wholesale services segment is weather sensitive, with typically increased earnings opportunities during periods of extreme weather conditions.

During the six months ended June 30, 2006, we derived approximately 88% of our earnings before interest and taxes (EBIT) from our regulated natural gas distribution business and the sale of natural gas to end-use customers primarily in Georgia through SouthStar. This statistic is significant because it represents the portion of our earnings that directly results from the underlying business of supplying natural gas to retail customers. Although SouthStar is not subject to the same regulatory framework as our utilities, it is an integral part of the retail framework for providing gas service to end-use customers in the state of Georgia. For more information regarding our measurement of EBIT, see Results of Operations – AGL Resources Inc.

The remaining 12% of our EBIT was principally derived from businesses that are complementary to our natural gas distribution business. We engage in natural gas asset management and the operation of high-deliverability natural gas underground storage as ancillary activities to our utility franchises. These businesses allow us to be opportunistic in capturing incremental value at the wholesale level, provide us with deepened business insight about natural gas market dynamics and facilitate our ability, in the case of asset management, to provide transparency to regulators as to how that value can be captured to benefit our utility customers through profit-sharing arrangements. Given the volatile and changing nature of the natural gas resource base in North America and globally, we believe that participation in these related businesses strengthens our business.

Regulatory Environment

In August 2005, the Energy Policy Act of 2005 (Energy Act) was enacted. The Energy Act authorized, among other things, the repeal of the Public Utility Holding Company Act of 1935, as amended (PUHCA). The effective date of the PUHCA repeal was February 8, 2006. The Energy Act gives the Federal Energy Regulatory Commission (FERC) increased authority over utility merger and acquisition activity, removes many of the geographic and structural restrictions on the ownership of public utilities and eliminates certain regulatory burdens. Some of the SEC reporting requirements, financing authorizations and affiliate relationship approvals that previously applied to us under the PUHCA were replaced by the requirements of the Energy Act.

In addition, the Energy Act requires a public utility holding company to maintain its books and records and make them available to the FERC and to comply with certain reporting requirements. However, the FERC may exempt a class of entities or class of transactions if the FERC finds that they are not relevant to the jurisdictional rate of a public utility or natural gas company. In February 2006, we requested exemption from the FERC, and in April 2006 our exemption from the regulations and reporting requirements under the Energy Act became effective.

Results of Operations

AGL Resources Inc.

Customer Gas Demand We experienced declines in per-household natural gas use that limited the potential increase in our residential natural gas demand and resulted in lower operating margins at our distribution operations and retail energy operations segments. Four key factors that have contributed to this decline are the addition of newer, more energy-efficient housing, efficiency improvements in residential appliances, warmer weather and historically higher natural gas prices.

Our customers have experienced sustained higher natural gas prices, including an average 34% increase in their natural gas bills during the most recent heating season (October 2005 – March 2006), in part driven by market concerns about the sufficiency of the supply of natural gas and other factors during the most recent winter heating season. Additionally, the mild weather experienced during the most recent heating season was on average 11% warmer than last year.

Seasonality The operating revenues and EBIT of our distribution operations, retail energy operations and wholesale services segments are seasonal. During the heating season natural gas usage and operating revenues are higher because generally more customers are connected to our distribution systems and because natural gas usage is higher in periods of colder weather than in periods of warmer weather. However, our base operating expenses, excluding cost of gas, interest expense and certain incentive compensation costs, are incurred relatively equally over any given year. Thus, our operating results vary significantly from quarter to quarter as a result of seasonality. Seasonality also affects the comparison of certain balance sheet items such as receivables, inventories and short-term debt across reporting periods.

Hedging Changes in commodity prices subject a significant portion of our operations to variability. Commodity prices tend to be higher in colder months. Our nonutility businesses principally use physical and financial arrangements to economically hedge the risks associated with both seasonal fluctuations in market conditions and changing levels of commodity prices and changing commodity prices. In addition, because these economic hedges are generally not designated for hedge accounting treatment, our reported earnings for the wholesale services and retail energy operations segments reflect changes in the fair values of certain derivatives; these values may change significantly from period to period.

Elizabethtown Gas utilizes certain derivatives in accordance with a hedging program directed by the New Jersey Board of Public Utilities to hedge the impact of market fluctuations in natural gas prices. These derivative products are marked to market each reporting period. In accordance with regulatory requirements, realized gains and losses related to these derivatives are reflected in purchased gas costs and ultimately included in billings to customers. Unrealized gains and losses are reflected as a regulatory asset (loss) or liability (gain), as appropriate, in our consolidated balance sheets.

Revenues We generate nearly all our operating revenues through the sale, distribution and storage of natural gas. We include in our consolidated revenues an estimate of revenues from natural gas distributed, but not yet billed, to residential and commercial customers from the latest meter reading date to the end of the reporting period.

Operating Margin and EBIT We evaluate the performance of our operating segments using the measures of operating margin and EBIT. We believe operating margin is a better indicator than revenues for the contribution resulting from customer growth in our distribution operations segment since the cost of gas can vary significantly and is generally passed directly to our customers. We also consider operating margin to be a better indicator in our retail energy operations, wholesale services and energy investments segments since it is a direct measure of gross profit before overhead costs. We believe EBIT is a useful measurement of our operating segments' performance because it provides information that can be used to evaluate the effectiveness of our businesses from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which is directly relevant to the efficiency of those operations.

Our operating margin and EBIT are not measures that are considered to be calculated in accordance with accounting principles generally accepted in the United States of America (GAAP). You should not consider operating margin or EBIT an alternative to, or a more meaningful indicator of, our operating performance than operating income or net income as determined in accordance with GAAP. In addition, our operating margin or EBIT measures may not be comparable to similarly titled measures of other companies.

Second quarter 2006 compared to second quarter 2005

The following table sets forth a reconciliation of our operating margin and EBIT to our operating income and net income, together with other consolidated financial information for the three months ended June 30, 2006 and 2005.

	Three months ended June 30,		
In millions, except per share amounts	2006	2005	Change
Operating revenues	$436	$431	$5
Cost of gas	219	209	10
Operating margin	217	222	(5)
Operating expenses	157	156	1
Operating income	60	66	(6)
Other income	-	1	(1)
Minority interest	-	(3)	3
EBIT	60	64	(4)
Interest expense	29	26	3
Earnings before income taxes	31	38	(7)
Income taxes	12	14	(2)
Net income	$19	$24	$(5)
Basic earnings per common share	$0.25	$0.31	$(0.06)
Diluted earnings per common share	$0.25	$0.30	$(0.05)
Weighted average number of common shares outstanding			
Basic	77.7	77.1	0.6
Diluted	78.1	77.8	0.3

Segment information Operating revenues, operating margin and EBIT information for each of our segments are contained in the following table for the three months ended June 30, 2006 and 2005:

(*in millions*)	Operating revenues	Operating margin	EBIT
2006			
Distribution operations	$293	$180	$59
Retail energy operations	153	17	-
Wholesale services	19	11	1
Energy investments	10	8	2
Corporate (1)	(39)	1	(2)
Consolidated	$436	$217	$60
2005			
Distribution operations	$293	$179	$52
Retail energy operations	160	24	6
Wholesale services	9	9	2
Energy investments	17	12	5
Corporate (1)	(48)	(2)	(1)
Consolidated	$431	$222	$64

(1) Includes intersegment eliminations

Our earnings per share and net income for the three months ended June 30, 2006 were lower than the prior year due to decreased earnings at retail energy operations, energy investments, wholesale services and corporate, offset by increased earnings at distribution operations. Additionally, interest expense was higher as compared to last year, offset by lower income taxes.

EBIT Consolidated EBIT for the second quarter of 2006 decreased by $4 million or 6% from the same period last year. EBIT decreased by $6 million at retail energy operations, $3 million at energy investments, $1 million at wholesale services and $1 million at corporate. This was partially offset by increased EBIT of $7 million at distribution operations.

Operating Margin Operating margin decreased $5 million or 2% from the same period last year. This decrease primarily reflects lower operating margins at retail energy operations of $7 million, driven by reduced consumption due to various factors including warmer weather and customer conservation. Additionally, the decrease includes lower operating margins of $4 million at energy investments due to dispositions during third quarter 2005 of businesses that were acquired with our 2004 acquisition of NUI, which are not reflected in our 2006 results. These decreases were offset by an increase in wholesale services' operating margin of $2 million primarily due to profits in its storage business. Distribution operations' operating margin increased $1 million primarily due to $2 million of increased gas storage carrying costs charged by Atlanta Gas Light in Georgia primarily due to higher inventory levels and the higher price of natural gas. This was slightly offset by reduced consumption of $1 million at Virginia Natural Gas due to conservation and warmer weather.

Operating Expenses Overall operating expenses increased $1 million due to increased expenses of $2 million at retail energy operations, $3 million at wholesale services and $3 million at corporate, offset by lower operating expenses at distribution operations of $6 million and energy investments of $1 million. The increase at retail energy operations was due primarily to higher bad debt expenses. The increase at wholesale services was due to increased compensation costs to support Sequent's growth. The decrease at distribution operations was primarily a result of reduced costs of $5 million from our 2005 restructurings.

Interest Expense The increase of $3 million or 12% was due primarily to higher average debt balances and higher short-term interest rates. Average debt balances increased by $262 million as shown in the table below. This was due primarily to higher inventory balances during 2006.

	Three months ended June 30,		
Dollars in millions	2006	2005	Change
Average debt outstanding (1)	$1,930	$1,668	$262
Average rate	6.0%	6.2%	(0.2)%

(1) Daily average of all outstanding debt.

Income Taxes The decrease in income tax expense of $2 million or 14% for 2006 compared to 2005 was primarily due to lower pre-tax income for the three months ended June 30, 2006.

Six months 2006 compared to six months 2005

The following table sets forth a reconciliation of our operating margin and EBIT to our operating income and net income, together with other consolidated financial information for the six months ended June 30, 2006 and 2005.

	Six months ended June 30,		
In millions, except per share amounts	2006	2005	Change
Operating revenues	$1,480	$1,343	$137
Cost of gas	874	781	93
Operating margin	606	562	44
Operating expenses	318	315	3
Operating income	288	247	41
Other (expense) income	(2)	2	(4)
Minority interest	(19)	(16)	(3)
EBIT	267	233	34
Interest expense	59	52	7
Earnings before income taxes	208	181	27
Income taxes	79	69	10
Net income	$129	$112	$17
Basic earnings per common share	$1.66	$1.45	$0.21
Diluted earnings per common share	$1.65	$1.44	$0.21
Weighted average number of common shares outstanding			
Basic	77.8	77.0	0.8
Diluted	78.2	77.7	0.5

Segment information Operating revenues, operating margin and EBIT information for each of our segments are contained in the following table for the six months ended June 30, 2006 and 2005:

In millions	Operating revenues	Operating margin	EBIT
2006			
Distribution operations	$933	$425	$182
Retail energy operations	543	111	54
Wholesale services	67	54	33
Energy investments	20	16	4
Corporate (1)	(83)	-	(6)
Consolidated	$1,480	$606	$267
2005			
Distribution operations	$927	$432	$175
Retail energy operations	474	90	46
Wholesale services	20	20	6
Energy investments	29	21	10
Corporate (1)	(107)	(1)	(4)
Consolidated	$1,343	$562	$233

(1) Includes intersegment eliminations

EBIT Consolidated EBIT for the six months ended June 30, 2006 increased by $34 million or 15% from the previous year. The increase reflects increased EBIT from wholesale services, retail energy operations and distribution operations. These increases were offset by lower EBIT at energy investments and corporate, as well as higher interest expense and income taxes.

Operating Margin Operating margin increased

$44 million, primarily reflecting improved margins at retail energy operations of $21 million due to improved optimization of storage and transportation assets and effective commodity risk management, offset by lower consumption in part due to warmer weather and other factors including conservation. Operating margin at wholesale services increased $34 million due to increased profits in its storage business. Distribution operations margins decreased by $7 million. The decrease included $9 million of lower operating margin primarily due to lower customer usage as a result of a warmer winter in 2006 than in 2005 and a decrease of $1 million as a result of the sale of our New Jersey and Florida appliance businesses.

These decreases were partially offset by increased operating margin at Atlanta Gas Light of $2 million primarily due to higher gas storage carrying charges due to higher inventory levels and the higher price of natural gas held in storage. Energy investments operating margin decreased $5 million primarily due to dispositions during third quarter 2005 of business that were acquired with our 2004 acquisition of NUI, which are not reflected in our 2006 results.

Operating Expenses Operating expenses increased $3 million due to increased operating expenses of $8 million at retail energy operations, $7 million at wholesale services and $2 million at corporate, offset by lower expenses in distribution operations of $14 million primarily due to our 2005 restructurings. Retail energy operations increase in operating expense was primarily due to higher bad debt expense resulting from higher commodity costs and an increase in aged accounts receivable balances resulting from increased number of customers on payment arrangements. The increase was also due to higher outside service costs associated with technology projects and higher compensation costs due to increased earnings. The increase at wholesale services was primarily due to higher compensation costs to support Sequent's growth and higher corporate overhead costs, offset by lower outside service costs.

Interest Expense Interest expense increased by $7 million from last year, primarily as a result of higher working capital requirements, primarily due to increased inventory balances. Most of our utilities experienced a warmer winter than in the prior year and consequently our utilities withdrew less volumes of natural gas inventory and Sequent operated with higher inventory balances during the current period as compared to 2005.

	Six months ended June 30,		
Dollars in millions	2006	2005	Change
Average debt outstanding (1)	$1,962	$1,743	$219
Average rate	6.0%	6.0%	-%

(1) Daily average of all outstanding debt.

If, for the six months ended June 30, 2006, market interest rates on our variable rate debt (average rate of 5.1% for the six month period) had been 100 basis points higher or lower, our year-to-date pretax interest expense would have changed by $3 million.

Income Taxes Income taxes increased by $10 million, primarily as a result of higher pre-tax income for the six months ended June 30, 2006. Our effective tax rate of 37.8% for the six months ended June 30, 2006 was slightly lower than the 38.3% effective tax rate in the same period last year, which slightly offset our increased income taxes driven by increased earnings before taxes.

Distribution Operations

Distribution operations includes our natural gas local distribution utility companies, which construct, manage and maintain natural gas pipelines and distribution facilities and serve approximately 2.3 million end-use customers. Our distribution utilities include:

- Atlanta Gas Light
- Elizabethtown Gas
- Virginia Natural Gas
- Florida City Gas
- Chattanooga Gas
- Elkton Gas

Each utility operates subject to regulations of the state regulatory agencies in its service territories with respect to rates charged to our customers, maintenance of accounting records and various other service and safety matters. Rates charged to our customers vary according to customer class (residential, commercial or industrial) and rate jurisdiction. Rates are set at levels that should generally allow for the recovery of all prudently incurred costs, including a return on rate base sufficient to pay interest on debt and provide a reasonable return on common equity. Rate base consists generally of the original cost of utility plant in service, working capital, inventories and certain other assets; less accumulated depreciation on utility plant in service, net of deferred income tax liabilities and certain other deductions. We continuously monitor the performance of our utilities to determine whether rates need to be adjusted through the regulatory process.

Updates The following is a summary of significant developments with regard to our distribution operations segment that have occurred since we filed our 2005 Annual Report on Form 10-K for the year ended December 31, 2005, as amended on June 1, 2006.

Virginia Natural Gas On July 24, 2006, the Virginia State Corporation Commission (Virginia Commission) issued its order approving Virginia Natural Gas' performance-based rate (PBR) plan with modifications. These modifications, which were made by the Virginia Commission, include a requirement to construct and report on the progress of a pipeline connecting Virginia Natural Gas' northern and southern systems and reporting requirements to monitor compliance with the terms of the PBR plan. The estimated cost to construct the pipeline is $48-$60 million. Virginia Natural Gas has 30 days from the date of the order to accept the terms of the PBR plan as modified by the Virginia Commission. If Virginia Natural Gas does not accept the terms of the PBR plan as modified, the Virginia Commission's order requires that Virginia Natural Gas' rates be reduced by approximately $10 million effective July 24, 2006. If Virginia Natural Gas accepts the Virginia Commission's order, the PBR plan, as modified, will be effective August 1, 2006 with base rates frozen at current levels for five years.

Chattanooga Gas On June 30, 2006, Chattanooga Gas filed a rate petition with the Tennessee Regulatory Authority (Tennessee Authority) that includes a proposed annual rate increase of approximately $6 million and a comprehensive rate design plan. The proposed rate increase is to cover Chattanooga Gas' rising costs of financing its operations and continued lower consumption of natural gas, the latter of which reduces the amount of costs Chattanooga Gas recovers from its customers. The comprehensive rate design plan includes an energy conservation program (ECP) and a conservation and usage adjustment (CUA). The ECP is designed to encourage energy conservation by customers, and the CUA is designed to mitigate the impacts to Chattanooga Gas as a result of expected increased energy conservation by customers. New rates would be effective January 1, 2007, subject to a final approval by the Tennessee Authority, which we expect by December 2006.

Results of Operations for our distribution operations segment for the three and six months ended June 30, 2006 and 2005 are shown in the following tables.

Second quarter 2006 compared to second quarter 2005

	Three months ended June 30,		
In millions	2006	2005	Change
Operating revenues	$293	$293	$-
Cost of gas	113	114	(1)
Operating margin	180	179	1
Operating expenses	122	128	(6)
Operating income	58	51	7
Other income	1	1	-
EBIT	$59	$52	$7

Heating degree days			% Warmer
Florida	3	41	93%
Georgia	98	199	51%
Maryland	422	571	26%
New Jersey	426	567	25%
Tennessee	130	236	45%
Virginia	224	354	37%

Operating Margin Operating margin increased $1 million in the three months ended June 30, 2006 as compared to the same period in 2005. The increase included a $2 million increase in gas storage carrying charges charged by Atlanta Gas Light in Georgia primarily due to higher inventory levels and the higher price of natural gas. This was slightly offset by reduced consumption of $1 million at Virginia Natural Gas due to conservation and warmer weather.

Operating Expenses Operating expenses decreased $6 million in 2006 as compared to the same period in 2005, primarily due to lower costs primarily related to our 2005 workforce and facilities restructuring.

Six months 2006 compared to six months 2005

In millions	Six months ended June 30, 2006	2005	Change
Operating revenues	$933	$927	$6
Cost of gas	508	495	13
Operating margin	425	432	(7)
Operating expenses	244	258	(14)
Operating income	181	174	7
Other income	1	1	-
EBIT	$182	$175	$7
Metrics			
Average end-use customers (in thousands)	2,271	2,263	0.4%
Operation and maintenance expenses per customer	$74	$81	(9%)
EBIT per customer	$80	$77	4%
Throughput (in millions of dekatherms)			
Firm	117	137	(15 %)
Interruptible	61	63	(3%)
Total	178	200	(11%)
Heating degree days			%Colder/ (Warmer)
Florida	493	401	23%
Georgia	1,491	1,595	(7%)
Maryland	2,676	3,255	(18%)
New Jersey	2,718	3,322	(18%)
Tennessee	1,688	1,781	(5%)
Virginia	1,866	2,329	(20%)

Operating Margin Operating margin decreased $7 million in the six months ended June 30, 2006 as compared to the same period in 2005. The decrease included $4 million of lower operating margin at Virginia Natural Gas and $3 million at Elizabethtown Gas due primarily to lower gas usage by customers as a result of a warmer winter in 2006 than in 2005. Florida City Gas' operating margin decreased $2 million due to lower customer usage. There was also an operating margin decrease of $1 million as a result of the sale of our New Jersey and Florida appliance businesses in the third and fourth quarters of 2005. These appliance businesses were part of the NUI acquisition in the fourth quarter of 2004. These decreases were offset by increased operating margin at Atlanta Gas Light of $2 million. This increase at Atlanta Gas Light included higher gas storage carrying charges of $3 million due to higher inventory levels and the higher price of natural gas held in storage and increased pipeline replacement program revenues of $1 million. Atlanta Gas Light's operating margin was reduced by $2 million due to the Georgia Public Service Commission's June 2005 Rate Order.

Operating Expenses Operating expenses decreased $14 million in 2006 as compared to the same period in 2005, primarily due to lower compensation expense, lower facilities expense and a gain in 2006 on the sale of properties, offset by increased bad debt expense.

Compensation and facilities expense decreased $12 million in 2006 as compared to the same period in 2005, primarily related to a restructure in 2005 of the workforce and elimination of unnecessary or redundant facilities. These decreases were offset by a $1 million increase in bad debt expense primarily at Virginia Natural Gas and Elizabethtown Gas due to higher gas prices in 2006. Operating expenses also reflect a $3 million gain on the sale of properties in Georgia.

Retail Energy Operations

Our retail energy operations segment consists of SouthStar, a joint venture owned 70% by our subsidiary, Georgia Natural Gas Company, and 30% by Piedmont Natural Gas Company, Inc. (Piedmont). SouthStar markets natural gas and related services to retail customers on an unregulated basis, principally in Georgia. Although our ownership interest in the SouthStar partnership is 70%, SouthStar's earnings are allocated by contract 75% to us and 25% to Piedmont.

Operating Margin SouthStar generates its operating margin primarily in three ways. The first is through the sale of natural gas to retail customers in the residential, commercial and industrial sectors, primarily in Georgia where SouthStar captures a spread between wholesale and retail natural gas prices. The second is through the collection of a monthly service fee and customer late payment fees. The combination of these two retail price components are evaluated by SouthStar to ensure such pricing is structured to cover related retail customer costs, such as bad debt expense, and lost and unaccounted for gas, among others and to provide a reasonable profit. SouthStar's operating margins are impacted by weather seasonality, natural gas prices, customer growth, and SouthStar's related market share in Georgia, which has historically ranged from 35% to 38%. SouthStar employs a strategy to attract and retain a higher quality customer base through the application of minimum credit requirements. This strategy results not only in higher operating margin contributions, as these customers tend to utilize higher volumes of natural gas, but also helps to mitigate bad debt expenses due to the higher credit quality of its customers.

The third way SouthStar generates margin is through the optimization of storage and transportation assets and effective commodity risk management. The efficient management of these assets and effective commodity risk management enable SouthStar to reduce its retail customer prices and realize profits. SouthStar is allocated storage and pipeline capacity on the Atlanta Gas Light distribution system that is utilized by SouthStar to provide gas supply to its customers in Georgia. Through hedging transactions, SouthStar manages exposures arising from changing commodity prices, utilizing natural gas storage transactions to capture margin from natural gas pricing differences that occur over time. SouthStar's risk management policies allow the use of derivative instruments for hedging and risk management purposes, but prohibit the use of derivative instruments for speculative purposes.

Updates The following is a summary of significant developments with regard to our retail energy operations segment that have occurred since we filed our 2005 Annual Report on Form 10-K for the year ended December 31, 2005, as amended on June 1, 2006.

Impact of High Natural Gas Prices

SouthStar's operating margin and EBIT from the sale of natural gas to retail customers during the three and six months ended June 30, 2006 were affected by lower customer usage, higher bad debt expenses and lost and unaccounted for gas as a result of higher natural gas prices in the 2005 – 2006 winter heating season. SouthStar's bad debt was $9 million for the six months ended June 30, 2006, a $5 million increase from the same period last year. The 2005 figures include an incremental $1 million relating to the application of aged customer deposits which reduced bad debt expense. Additionally, the increase in bad debt was impacted by an increase in the amount of accounts receivable balances past due more than 60 days. This was largely driven by SouthStar's offering of payment arrangements to customers in its efforts to help customers with higher natural gas bills. SouthStar expects that these efforts will help mitigate the overall impact of bad debt expense (exclusive of the 2005 $1 million effect from the application of aged customer deposits) as a percentage of operating revenues, which were 1.6% for the six months ended June 30, 2006 as compared to approximately 1.0% for the same period last year.

SouthStar also has experienced lower average usage per customer as compared to the same period last year due in part to a number of factors including warmer weather and the effects of customer conservation. Increased customer conservation is believed to be attributable to a number of factors including weather patterns, higher gas prices and the ongoing effects from replacement of natural gas appliances with more efficient units, among others. The impact was an $11 million decrease in operating margin for the six months ended June 30, 2006, as compared to last year and primarily occurred when natural gas prices were higher during the first quarter, and when weather was more than 50% warmer in second quarter of 2006 as compared to last year.

Results of operations for our retail energy operations segment for the three and six months ended June 30, 2006 and 2005 are shown in the following tables.

Second quarter 2006 compared to second quarter 2005

	Three months ended June 30,		
In millions	2006	2005	Change
Operating revenues	$153	$160	$(7)
Cost of sales	136	136	-
Operating margin	17	24	(7)
Operating expenses	17	15	2
Operating income	-	9	(9)
Minority interest (1)	-	(3)	3
EBIT	$-	$6	$(6)

(1) Minority interest adjusts our earnings to reflect our 75% share of SouthStar's earnings.

Operating Margin Operating margin decreased $7 million, or 29%, largely driven by lower retail margins of $5 million due to lower average usage and customer conservation in part due to weather that was more than 50% warmer than last year. Late payment fees were also lower due to increased payment arrangements. Operating margins also decreased by $2 million as compared to last year primarily due to higher storage carrying charges.

Operating Expenses Operating expenses increased $2 million or 13% primarily due to higher bad debt expense.

Minority Interest Minority interest decreased $3 million as a result of decreased operating income in the second quarter of 2006 as compared to 2005.

Six months 2006 compared to six months 2005

	Six months ended June 30,		
In millions	2006	2005	Change
Operating revenues	$543	$474	$69
Cost of sales	432	384	48
Operating margin	111	90	21
Operating expenses	36	28	8
Operating income	75	62	13
Other expense	2	-	2
Minority interest (1)	(19)	(16)	(3)
EBIT	$54	$46	$8
Metrics			
YTD average customers (in thousands)	538	536	0.4 %
Market share in Georgia	35%	35%	-%
Customer usage (in millions of dekatherms)	21.7	24.9	(13%)

(1) Minority interest adjusts our earnings to reflect our 75% share of SouthStar's earnings.

Operating Margin Operating margin increased $21 million or 23% largely driven by improved storage margins of $24 million, offset by lower retail operating margins of $3 million. Storage margins were driven by improved optimization of storage and transportation assets and effective commodity risk management. Retail operating margins decreased primarily due to lower average usage due to weather that was 7% warmer than last year, customer conservation and lower late payment fees of $1 million due to an increase in the number of customers on payment arrangements, offset by favorable retail price spreads.

Operating Expenses Operating expenses increased $8 million or 29% primarily due to higher bad debt expense of $5 million, higher variable benefit costs of $1 million as a result of continued earnings growth as compared to last year, $1 million of increased depreciation due to prior year system enhancements and higher outside service costs of $1 million driven by the current year implementation of a new Energy Trading and Risk Management system.

Minority Interest Minority interest increased $3 million as a result of increased operating income in 2006 as compared to 2005.

Wholesale Services

Wholesale services consists of Sequent, our subsidiary involved in asset management, transportation, storage, producer and peaking services and wholesale marketing. Our asset management business focuses on capturing economic value from idle or underutilized natural gas assets, which are typically amassed by companies via investments in, or contractual rights to, natural gas transportation and storage assets. Margin is typically created in this business by participating in transactions that balance the needs of varying markets and time horizons.

Sequent provides its customers with natural gas from the major producing regions and market hubs primarily in the eastern and mid-continental United States. In the second quarter, Sequent entered into an agreement which should facilitate the expansion of our operations into the western United States. Sequent also purchases transportation and storage capacity to meet its delivery requirements and customer obligations in the marketplace. Sequent's customers benefit from its logistics expertise and ability to deliver natural gas at prices that are advantageous relative to other alternatives available to its end-use customers.

Seasonality Fixed cost commitments are generally incurred evenly over the year, while margins generated through the use of the related assets are greatest in the winter heating season and occasionally in the summer due to peak usage by power generators in response to summer energy demands. This increases the seasonality of Sequent's business, generally resulting in higher margins in the first and fourth quarters.

Updates The following is a summary of significant developments with regard to our wholesale services segment that have occurred since we filed our 2005 Annual Report on Form 10-K for the year ended December 31, 2005, as amended on June 1, 2006.

Asset Management Transactions Our asset management customers include our own utilities, nonaffiliated utilities, municipal utilities and large industrial customers. The following table provides information about the fees and profits that Sequent has paid to its affiliated utilities during the periods indicated.

	Profits shared / fees paid		
In millions	2006 (1)	2005 (1)	2005 (2)
Atlanta Gas Light	$6	$3	$4
Chattanooga Gas	4	2	2
Elizabethtown Gas	4	-	-
Elkton Gas	-	-	-
Florida Gas	-	-	-
Virginia Natural Gas	-	-	5

(1) For the six months ended June 30.
(2) For the twelve months ended December 31.

Transportation Transactions In our wholesale marketing and risk management business, Sequent contracts for natural gas transportation capacity. We participate in transactions to manage the natural gas commodity and transportation costs that result in the lowest cost to serve our various markets. We seek to optimize this process on a daily basis as market conditions change by evaluating all the natural gas supplies, transportation alternatives and markets to which we have access and identifying the least-cost alternatives to serve our various markets. This enables us to capture geographic pricing differences across these various markets as delivered gas prices change. During the first quarter of 2006, we entered into a contract for 35,000 million British thermal units (MMBtu's) per day of firm transportation capacity for a term of five years with an estimated commencement date in late 2007. The contract contained a five year extension option, which we exercised during the second quarter of 2006. This contract is subject to our counterparty receiving regulatory approval of their construction project. Once the contract commences, our cost for the capacity will be approximately $3 million per year.

Energy Marketing and Risk Management Activities The tables below illustrate the change in the net fair value of Sequent's derivative instruments and energy-trading contracts during the three and six months ended June 30, 2006 and 2005, and provide details of the net fair value of contracts outstanding as of June 30, 2006. Sequent's storage positions are affected by changes in the NYMEX average price.

	Three months ended June 30,	
In millions	2006	2005
Net fair value of contracts outstanding at beginning of period	$20	$11
Contracts realized or otherwise settled during period	(5)	8
Change in net fair value of contracts	39	(11)
Net fair value of contracts outstanding at end of period	54	8
Less net fair value of contracts outstanding at beginning of period	20	11
Unrealized gain (loss) related to changes in the fair value of derivative instruments	$34	$(3)

	Six months ended June 30,	
In millions	2006	2005
Net fair value of contracts outstanding at beginning of period	$(13)	$17
Contracts realized or otherwise settled during period	22	17
Change in net fair value of contracts	45	(26)
Net fair value of contracts outstanding at end of period	54	8
Less net fair value of contracts outstanding at beginning of period	(13)	17
Unrealized gain (loss) related to changes in the fair value of derivative instruments	$67	$(9)

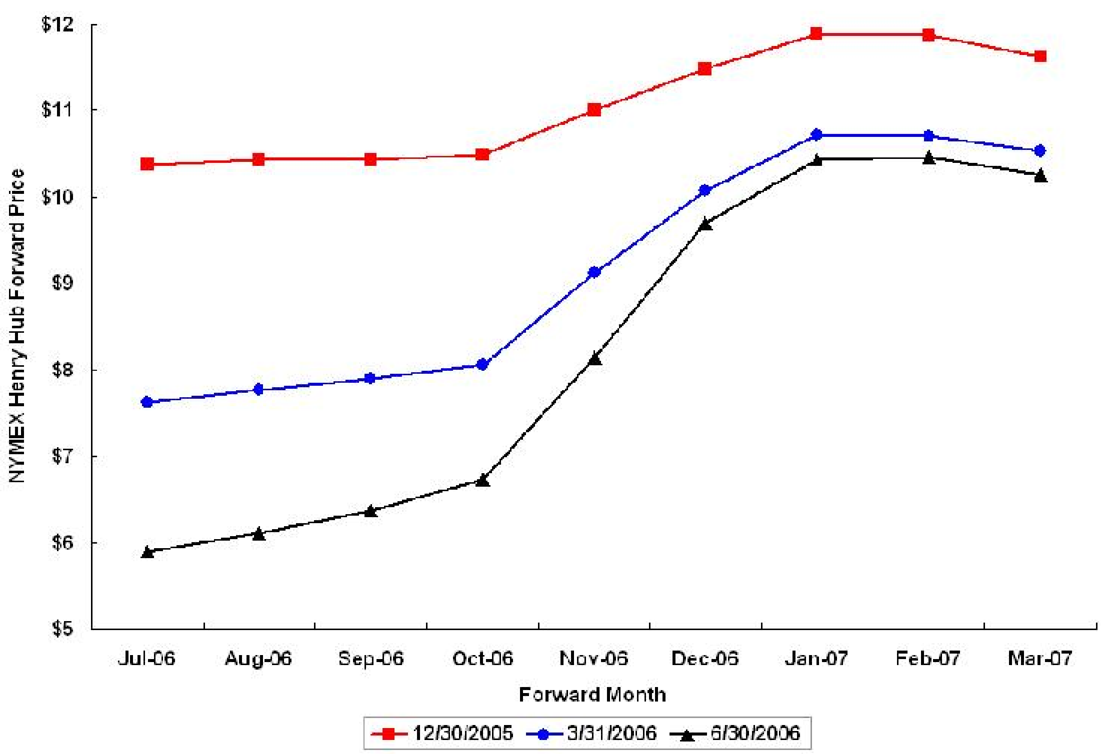
The sources of our net fair value at June 30, 2006 are as follows.

In millions	Prices actively quoted	Prices provided by other external sources
Maturity less than one year	$32	$20
Maturity 1-2 years	(1)	2
Maturity greater than three years	-	1
Total net fair value	$31	$23

The "prices actively quoted" category represents Sequent's positions in natural gas, which are valued exclusively using NYMEX futures prices. "Prices provided by other external sources" are transactions that represent the cost to transport the commodity from a NYMEX delivery point to the contract delivery point. Our basis spreads are primarily based on quotes obtained either directly from brokers or through electronic trading platforms.

At June 30, 2006, Sequent's commodity-related derivative financial instruments represented purchases (long) of 578 billion cubic feet (Bcf) and sales (short) of 639 Bcf, with approximately 97% and 96% scheduled to mature in less than 2 years and the remaining 3% and 4% in three to nine years, respectively. At June 30, 2006, the fair value of these derivatives was reflected in our condensed consolidated balance sheet as an asset of $93 million and a liability of $39 million.

Storage Inventory Outlook The following graph presents the NYMEX forward natural gas prices as of December 31, 2005, March 31, 2006 and June 30, 2006 for the period July 2006 through March 2007, and reflects the prices at which Sequent could buy natural gas at the Henry Hub for delivery in the same time period. The Henry Hub, located in Louisiana, is the largest centralized point for natural gas spot and futures trading in the United States. NYMEX uses the Henry Hub as the point of delivery for its natural gas futures contracts. Many natural gas marketers also use the Henry Hub as their physical contract delivery point or their price benchmark for spot trades of natural gas.



Sequent's expected withdrawals from physical salt dome and reservoir storage are presented in the table below along with its expected gross margin. Sequent's expected gross margin is net of the impact of regulatory sharing and reflects the amounts that we would expect to realize in future periods based on the inventory withdrawal schedule and forward natural gas prices at June 30, 2006. Sequent's storage inventory is fully hedged with futures as its NYMEX short positions are equal to the physical long positions, which results in an overall locked-in margin, timing notwithstanding. Sequent's physical salt dome and reservoir volumes are presented in NYMEX equivalent contract units of 10,000 MMBtu's.

	Q3 2006	Q4 2006	Q1 2007	Total
Physical withdrawal schedule *(in MMBtu)*				
Salt dome	-	317	53	370
Reservoir	739	527	580	1,846
	739	844	633	2,216
Expected gross margin *(in millions)*	$-	$13	$15	$28

As of June 30, 2006, the weighted average cost of natural gas in inventory was $6.775 for physical salt dome storage and $6.797 for physical reservoir storage. These costs reflect adjustments that were recorded at the end of the first and second quarters of 2006 in order to reduce the value of Sequent's natural gas inventory to market value at certain locations. Sequent reduced the inventory value by $5 million and $8 million after regulatory sharing at March 31 and June 30, respectively, or $13 million for the six months ended June 30, 2006. These adjustments negatively impacted Sequent's reported earnings; however, as the carrying value of the inventory was reduced, the expected gross margin in the table above increased by an equal and offsetting amount. We anticipate that $12 million of the aggregate $13 million of adjustments will be recovered during the current year as inventory is withdrawn from storage.

As noted above, Sequent's inventory level and pricing as of June 30, 2006 should result in a gross margin of approximately $13 million in 2006 and $15 million in 2007 if all factors remain the same. This could change significantly if Sequent adjusts its daily injection and withdrawal plans in response to changes in market conditions in future months. Based upon Sequent's storage positions at June 30, 2006, a $1.00 change in the forward NYMEX prices would result in an $18 million impact to Sequent's reported EBIT after regulatory sharing. However, most of Sequent's inventory is scheduled for withdrawal during 2006 and therefore the current year-end sensitivity to a $1.00 change in the 2007 forward NYMEX prices is expected to be $6 million after regulatory sharing.

Park and Loan Transactions Sequent enters into park and loan transactions with various pipelines. A park and loan transaction is a tariff transaction offered by pipelines in which the pipeline allows the customer to park gas on or borrow gas from the pipeline in one period and reclaim gas from or repay gas to the pipeline in a subsequent period. The economics of these transactions are evaluated and price risks are managed similar to the way traditional reservoir and salt dome storage transactions are evaluated and managed.

During the 2006 spring and summer months, natural gas prices have been significantly less than the future prices in the upcoming 2006/2007 winter months. As a result, Sequent has been entering into transactions to park natural gas with the pipelines during the summer and receive the natural gas back during the winter.

Sequent enters into forward NYMEX contracts to hedge its park and loan transactions. While the hedging instruments mitigate the price risk associated with the delivery and receipt of natural gas, they can also result in volatility in Sequent's reported results during the period before the initial delivery or receipt of natural gas. During this period if the forward NYMEX prices of the delivery and receipt months do not change in equal amounts, Sequent will report a net unrealized gain or loss.

As of June 30, 2006 Sequent reported unrealized losses of $4 million associated with its park and loan hedging instruments. The majority of these losses will be recovered during the third quarter as the initial delivery of natural gas occurs. Sequent did not report any significant gains or losses on park and loan hedges during 2005. Sequent expects its park and loan transactions to generate approximately $5 million in gross margin in the third and fourth quarters of 2006.

Results of Operations for Sequent's wholesale services segment for the three and six months ended June 30, 2006 and 2005 are as follows:

Second quarter 2006 compared to second quarter 2005

	Three months ended June 30,		
In millions	2006	2005	Change
Operating revenues	$19	$9	$10
Cost of sales	8	-	8
Operating margin	11	9	2
Operating expenses	10	7	3
Operating income	1	2	(1)
Other income	-	-	-
EBIT	$1	$2	$(1)

Metrics			
Physical sales volumes (Bcf/day)	2.09	2.13	(2)%

Operating Margin The $2 million increase in operating margin was a result of more opportunities for Sequent's asset management and trading operations to capture storage margins in both the current period and the forward markets. The improvement from the prior year period also was the result of changes in natural gas prices and the associated effect on the fair values of Sequent's derivatives and the recognition of these changes in earnings, partially offset by the impact of a lower-of-cost-or-market adjustment to Sequent's natural gas inventory.

During the second quarter of 2006, there was a decline in forward NYMEX prices, which resulted in the recognition of unrealized gains of $16 million associated with the financial instruments used to hedge Sequent's inventory held in storage. Partially offsetting the unrealized gains were $4 million of unrealized losses associated with the impact of forward NYMEX price fluctuations on the financial instruments used to hedge Sequent's park and loan transactions. During the second quarter of 2005, forward NYMEX prices also declined; however, the impact was only $6 million as the price change was less significant and Sequent's inventory levels were lower.

Also, due to the decline in natural gas prices during 2006, we were required to evaluate the weighted average cost of Sequent's natural gas inventory. As a result, Sequent recorded a lower-of-cost-or-market adjustment of $8 million after regulatory sharing, which is presented as "Cost of sales". Sequent was not required to make similar adjustments during 2005

Operating Expenses Sequent's operating expenses increased $3 million primarily due to higher costs associated with an increase in the number of employees to support Sequent's growth and associated incentive compensation costs, as well as higher corporate overhead costs. The increased expenses were partially offset by lower costs associated with outside services.

Six months 2006 compared to six months 2005

	Six months ended June 30,		
In millions	2006	2005	Change
Operating revenues	$67	$20	$47
Cost of sales	13	-	13
Operating margin	54	20	34
Operating expenses	21	14	7
Operating income	33	6	27
Other income	-	-	-
EBIT	$33	$6	$27

Metrics			
Physical sales volumes (Bcf/day)	2.10	2.24	(6)%

Operating Margin The $34 million increase in operating margin was a result of more opportunities for Sequent's asset management and trading operations to capture storage margins in both the current period and the forward markets. The improvement from the prior year period also was the result of changes in natural gas prices and the associated effect on the fair values of Sequent's derivatives and the recognition of these changes in earnings, partially offset by the impact of a lower-of-cost-or-market adjustment to Sequent's natural gas inventory.

During 2004, there was a significant decline in forward NYMEX prices, which resulted in the recognition of unrealized gains associated with the financial instruments used to hedge Sequent's inventory held in storage. The majority of this inventory was scheduled for withdrawal during the first quarter of 2005 and, as a result, $5 million of margin that was originally anticipated to be recognized during the first quarter of 2005 was recognized in 2004.

Also, as a result of an increase in forward NYMEX prices during the first quarter of 2005, the results for that period reflect the recognition of $8 million of unrealized losses associated with Sequent's inventory hedges. Forward prices did decline during the second quarter of 2005 and resulted in the recovery of $6 million of the previously recorded losses. In contrast, forward NYMEX prices continually declined during the first and second quarters of 2006, which resulted in the recognition of an aggregate of $22 million of unrealized gains associated with storage hedges. Partially offsetting the current year unrealized gains was $4 million of unrealized losses associated with the impact of forward NYMEX price fluctuations on Sequent's park and loan hedges and lower-of-cost-or-market adjustments of $13 million (included in cost of sales). Sequent was not required to make similar lower-of-cost-or-market adjustments during the six months ended June 30,2005.

Additionally, results for 2006 were positively impacted by the recognition of $10 million of additional economic value when inventory was withdrawn from storage. This value was carried-over from 2005 and was associated with previously recognized inventory hedge losses of $7 million and lower-of-cost-or-market adjustments of $3 million.

Operating Expenses Sequent's operating expenses increased $7 million primarily due to higher costs associated with an increase in the number of employees to support Sequent's growth and additional incentive compensation costs directly related to stronger financial performance in the first six months of 2006, as well as higher corporate overhead costs. The increased expenses were partially offset by lower costs associated with outside services.

Energy Investments

Our energy investments segment includes:

- Pivotal Jefferson Island Storage & Hub, LLC (Pivotal Jefferson Island)
- Pivotal Propane of Virginia, Inc. (Pivotal Propane)
- AGL Networks, LLC (AGL Networks)

Pivotal Jefferson Island - Operating Margin
Pivotal Jefferson Island generates operating margin primarily through entering into contracts with customers for the purchase of capacity in its salt dome caverns. Pivotal Jefferson Island's capacity in its currently operational caverns is fully subscribed, with the terms of subscription contracts expiring at staggered dates from 2007 to 2012. Pivotal Jefferson Island also generates operating margin from interruptible customers when market conditions and the amount of available physical space in the caverns are conducive for customers to store gas in the caverns.

Sale of assets Until their sale in August 2005, our energy investment segment included our 50% interest in Saltville Gas Storage Company, LLC (Saltville) and associated subsidiaries and our wholly-owned subsidiaries, Virginia Gas Pipeline and Virginia Gas Storage. These companies, which we acquired in our purchase of NUI in 2004, were sold for $66 million to a subsidiary of Duke Energy Corporation, the other 50% partner in the Saltville joint venture.

Results of operations for our energy investments segment for the three and six months ended June 30, 2006 and 2005 are as follows.

Second quarter 2006 compared to second quarter 2005

	Three months ended June 30,		
In millions	2006	2005	Change
Operating revenues	$10	$17	$(7)
Cost of sales	2	5	(3)
Operating margin	8	12	(4)
Operating expenses	6	7	(1)
Operating income	2	5	(3)
Other income	-	-	-
EBIT	$2	$5	$(3)

Operating Margin Operating margin decreased $4 million largely due to the loss of operating margin contributions from certain assets we acquired with the 2004 acquisition of NUI but later sold in 2005, as discussed above. These losses were partially offset by a $1 million increase in operating margin at Pivotal Jefferson Island as compared to the prior year, in part due to an increase in interruptible margin opportunities.

Operating Expenses Operating expenses decreased $1 million as compared to last year primarily due to decreased operating expenses resulting from the 2005 sales of certain assets that we originally acquired with the 2004 acquisition of NUI.

Six months 2006 compared to six months 2005

In millions	Six months ended June 30, 2006	2005	Change
Operating revenues	$20	$29	$(9)
Cost of sales	4	8	(4)
Operating margin	16	21	(5)
Operating expenses	12	12	-
Operating income	4	9	(5)
Other income	-	1	(1)
EBIT	$4	$10	$(6)

Operating Margin Operating margin decreased $5 million largely due to the loss of $6 million of operating margin contributions from certain assets we acquired with the 2004 acquisition of NUI but later sold in 2005. Pivotal Jefferson Island's operating margin increased slightly as compared to the prior year in part due to increased interruptible margin opportunities. AGL Networks' operating margin increased slightly and Pivotal Propane contributed a $1 million increase primarily in the first quarter of 2006 as it did not become operational until April 2005.

Operating Expenses Operating expenses were flat as compared to last year. Operating expenses at Pivotal Propane increased as it did not become operational until April 2005. Additionally, operating expenses at Pivotal Jefferson Island increased due to compressor related costs, and costs associated with our Pivotal Energy Development division were charged to the energy investments segment in 2006. These costs had been charged to our corporate segment in 2005. These costs were offset by decreased operating expenses resulting from the 2005 sale of certain assets that we originally acquired with the 2004 acquisition of NUI.

Other Income Other income decreased by $1 million due to the loss of earnings contributions from Saltville, which was sold in 2005.

Corporate

Our corporate segment includes our nonoperating business units, including AGL Services Company (AGSC) and AGL Capital Corporation (AGL Capital).

We allocate substantially all of AGSC's and AGL Capital's operating expenses and interest costs to our operating segments in accordance with state regulations. Our operating segments EBIT include the impact of these allocations. Our corporate segment also includes intersegment eliminations for transactions between our operating business segments.

Results of operations for our corporate segment for the three and six months ended June 30, 2006 and 2005 are listed in the tables below. The corporate segment is a non-operating segment, and as such, comparative EBIT variances for the indicated periods primarily reflect the relative change in various general and administrative expenses, such as payroll, benefits and incentives, insurance, fleet services and outside services.

Second quarter 2006 compared to second quarter 2005

.

In millions	Three months ended June 30, 2006	2005	Change
Operating revenues	$(39)	$(48)	$9
Cost of sales	(40)	(46)	6
Operating margin (1)	1	(2)	3
Operating expenses (2)	2	(1)	3
Operating loss	(1)	(1)	-
Other loss	(1)	-	(1)
EBIT	$(2)	$(1)	$(1)

(1) Includes intersegment eliminations

(2) The following table summarizes the major components of operating expenses, none of which are individually material, as compared to the prior year.

In millions	Three months ended June 30, 2006	2005	Change
Payroll	14	15	(1)
Benefits and incentives	6	6	-
Outside services	10	10	-
All other expenses	10	13	(3)
Allocations	(38)	(45)	7
Total operating expenses	2	(1)	3

Six months 2006 compared to six months 2005

	Six months ended June 30,		
In millions	2006	2005	Change
Operating revenues	$(83)	$(107)	$24
Cost of sales	(83)	(106)	23
Operating margin (1)	-	(1)	1
Operating expenses (2)	5	3	2
Operating loss	(5)	(4)	(1)
Other loss	(1)	-	(1)
EBIT	$(6)	$(4)	$(2)

(1) Includes intersegment eliminations
(2) The following table summaries the major components of operating expenses, none of which are individually material, as compared to the prior year.

	Six months ended June 30,		
In millions	2006	2005	Change
Payroll	27	28	(1)
Benefits and incentives	14	15	(1)
Outside services	21	19	2
All other expenses	24	28	(4)
Allocations	(81)	(87)	6
Total operating expenses	5	3	2

Liquidity and Capital Resources

To meet our capital and liquidity requirements, we rely on operating cash flow; short-term borrowings under our commercial paper program, which is backed by our supporting credit agreement (Credit Facility); borrowings under Sequent's, Pivotal Utility's and SouthStar's lines of credit; and borrowings or stock issuances in the long-term capital markets. Our issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by state and federal regulatory bodies, including state public service commissions and the SEC. Furthermore, a substantial portion of our consolidated assets, earnings and cash flow is derived from the operation of our regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to us is subject to regulation. The availability of borrowings under our Credit Facility is limited and subject to a total-debt-to-capital ratio financial covenant specified within the Credit Facility, which we currently meet.

We believe these sources will be sufficient for our working capital needs, debt service obligations and scheduled capital expenditures for the foreseeable future. The relatively stable operating cash flows of our distribution operations businesses currently contribute most of our cash flow from operations, and we anticipate this to continue in the future.

We will continue to evaluate the need to increase our available liquidity based on our view of working capital requirements, including the impact of changes in natural gas prices, liquidity requirements established by the rating agencies and other factors. Additionally, our liquidity and capital resource requirements may change in the future due to a number of other factors, some of which we cannot control. These factors include:

- the seasonal nature of the natural gas business and our resulting short-term borrowing requirements, which typically peak during colder months
- increased gas supplies required to meet our customers' needs during cold weather
- changes in wholesale prices and customer demand for our products and services
- regulatory changes and changes in ratemaking policies of regulatory commissions
- contractual cash obligations and other commercial commitments
- interest rate changes
- pension and postretirement funding requirements
- changes in income tax laws
- margin requirements resulting from significant increases or decreases in our commodity prices
- operational risks
- the impact of natural disasters, including weather

Seasonality The seasonal nature of our sales affects the comparison of certain balance sheet items at June 30, 2006, December 31, 2005 and June 30, 2005, such as receivables, inventories and short-term debt. We have presented the condensed consolidated balance sheet as of June 30, 2005 to provide comparisons of these items to December 31, 2005 and June 30, 2006.

Contractual Obligations and Commitments We have incurred various contractual obligations and financial commitments in the normal course of our operating and financing activities. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements. These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related revenue-producing activities.

We calculate any required pension contributions using the projected unit credit cost method. Under this method, we are not required to make any pension contributions in 2006. The following table illustrates our expected future contractual obligations as of June 30, 2006.

	Payments due before December 31,				
In millions	Total	2006	2007 & 2008	2009 & 2010	2011 & thereafter
Pipeline charges, storage capacity and gas supply (1) (2)	$1,725	$163	$562	$448	$552
Long-term debt	1,632	-	2	2	1,628
Interest charges on outstanding debt (3)	1,445	46	198	198	1,003
Short-term debt	455	455	-	-	-
PRP costs (4)	249	15	71	95	68
Operating leases (5)	149	14	46	32	57
Environmental remediation costs (4)	101	7	18	68	8
Commodity and transportation charges	2	2	-	-	-
Total	$5,758	$702	$897	$843	$3,316

(1) Charges recoverable through a PGA mechanism or alternatively billed to Marketers. Also includes demand charges associated with Sequent

(2) A subsidiary of NUI entered into two 20-year agreements for the firm transportation and storage of natural gas during 2003 with annual aggregate demand charges of approximately $5 million. As a result of our acquisition of NUI and in accordance with SFAS No. 141, "Business Combinations," we valued the contracts at fair value and established a long-term liability that will be amortized over the remaining lives of the contracts

(3) Floating rate debt is based on the interest rate as of June 30, 2006 and the maturity of the underlying debt instrument.

(4) Includes charges recoverable through rate rider mechanisms.

(5) We have certain operating leases with provisions for step rent or escalation payments and certain lease concessions. We account for these leases by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms, in accordance with SFAS No. 13, "Accounting for Leases." However, this accounting treatment does not affect the future annual operating lease cash obligations as shown herein.

We also have incurred various financial commitments in the normal course of business. Contingent financial commitments represent obligations that become payable only if certain predefined events occur, such as financial guarantees, and include the nature of the guarantee and the maximum potential amount of future payments that could be required of us as the guarantor. The following table illustrates our expected contingent financial commitments as of June 30, 2006.

		Commitments due before Dec. 31,	
In millions	Total	2006	2007 & thereafter
Standby letters of credit and performance and surety bonds	$21	$11	$10

Cash flow provided from operating activities For the first six months of 2006, our net cash flow provided from operating activities was $237 million, a decrease of $108 million or 31% from the same period last year.

The decrease was primarily a result of increased working capital requirements, which was primarily attributable to lower sales of gas from inventory of $50 million at our utilities and increased natural gas inventory injections at Sequent. Due to mild weather in the prior heating season our utilities and SouthStar sold less natural gas inventory than in the same period last year. Additionally, the decrease included lower recoveries of gas costs through the purchased gas adjustment mechanisms of our regulated utilities of $37 million, and higher payments for interest and taxes of $6 million with the remainder of the decrease attributable to higher working capital requirements related to higher commodity prices.

Cash flow used in investing activities Our cash used in investing activities consists primarily of property, plant and equipment expenditures. We made investments of $113 million in the six months ended June 30, 2006 and $130 million in the same period in 2005.

The decrease of $17 million is primarily due to the $32 million asset acquisition of a 250-mile pipeline in Georgia from Southern Natural Gas in 2005. This decrease was offset by higher expenditures of $12 million at our corporate segment on information technology projects and $5 million at Pivotal Jefferson Island as its cavern expansion project was started in 2006.

In 2006, we received approximately $5 million for the sale of land associated with former operating sites.

Cash flow used in financing activities Our financing activities primarily consist of borrowings and payments of short-term debt, distributions to minority interests, cash dividends on our common stock and issuances of common stock. Our capitalization and financing strategy is intended to ensure that we are properly capitalized with the appropriate mix of equity and debt securities. This strategy includes active management by us of the percentage of our total debt relative to our total capitalization, as well as the term and interest rate profile of our debt securities.

We also work to maintain or improve our credit ratings on our senior notes to effectively manage our existing financing costs and enhance our ability to raise additional capital on favorable terms. Factors we consider important in assessing our credit ratings include our balance sheet leverage, capital spending, earnings, cash flow generation, available liquidity and overall business risks. We do not have any trigger events in our debt instruments that are tied to changes in our credit ratings or our stock price and have not entered into any transaction that would require us to issue equity based on credit ratings or other trigger events. As of June 30 2006, our senior unsecured debt ratings are BBB+ from Standard & Poor’s Ratings Services (S&P), Baa1 from Moody’s Investors Service (Moody’s) and A- from Fitch Ratings (Fitch).

Our debt instruments and other financial obligations include provisions that, if not complied with, could require early payment, additional collateral support or similar actions. Our most important default events include maintaining covenants with respect to maximum leverage ratio, insolvency events, nonpayment of scheduled principal or interest payments, and acceleration of other financial obligations and change of control provisions. Our Credit Facility’s financial covenants require us to maintain a ratio of total debt to total capitalization of no greater than 70%; however, our goal is to maintain debt levels between 50% and 60% of total capitalization. We are currently in compliance with all existing debt provisions and covenants.

We believe that accomplishing these capitalization objectives and maintaining sufficient cash flow are necessary to maintain our investment-grade credit ratings and to allow us access to capital at reasonable costs. The components of our capital structure, as of the dates indicated, are summarized in the following table:

$ in millions	June 30, 2006		December 31, 2005		June 30, 2005	
Short-term debt	$454	12%	$521	14%	$171	5%
Current portion of long-term debt	1	-	1	-	1	-
Long-term debt (1)	1,632	45	1,615	45	1,621	50
Total debt	2,087	57	2,137	59	1,793	55
Common shareholders' equity	1,573	43	1,499	41	1,457	45
Total capitalization	$3,660	100%	$3,636	100%	$3,250	100%

(1) Net of interest rate swaps

In May 2006, we used the proceeds from the sale of commercial paper to redeem $150 million principal amount of junior subordinated debentures and to pay a $5 million note representing our investment in the related Trusts. We refinanced the commercial paper borrowings with long-term debt on June 27, 2006. See "Note 7 – Debt" in "Notes to Condensed Consolidated Financial Statements (Unaudited)" in Item 1 of Part I of this report.

Critical Accounting Policies and Estimates

The preparation of our financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. We evaluate our estimates on an ongoing basis, and our actual results may differ from these estimates. Our critical accounting policies used in the preparation of our consolidated financial statements are described in our Annual Report on Form 10-K, as amended, for the year ended December 31, 2005 and include the following:

- Pipeline Replacement Program
- Environmental Remediation Liabilities
- Derivatives and Hedging Activities
- Accounting for Contingencies
- Accounting for Pension and Other Postretirement Benefits

Each of our critical accounting policies and estimates involves complex situations requiring a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our financial statements. There have been no significant changes to our critical accounting policies from those disclosed in our Annual Report on Form 10-K as amended for the year ended December 31, 2005.

Accounting Developments

For information regarding accounting developments, see "Note 1 – Accounting Policies and Methods of Application," and "Note 5 - Stock-based Compensation Plans" in "Notes to Condensed Consolidated Financial Statements (Unaudited)" in Item 1 of Part I of this report.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to risks associated with commodity prices, interest rates and credit. Commodity price risk is defined as the potential loss that we may incur as a result of changes in the fair value of a particular instrument or commodity. Interest rate risk results from our portfolio of debt and equity instruments that we issue to provide financing and liquidity for our business. Credit risk results from the extension of credit throughout all aspects of our business but is particularly concentrated at Atlanta Gas Light in distribution operations and in wholesale services. Our risk management activities and related accounting treatments are described in further detail in "Note 2, - Risk Management" in "Notes to Condensed Consolidated Financial Statements (Unaudited)" in Item 1 of Part I of this report.

Commodity Price Risk

We employ a systematic approach to evaluating and managing the risks associated with our contracts related to wholesale marketing and risk management, including Value at Risk (VaR). A 95% confidence interval is used to evaluate our exposures. A 95% confidence interval means there is a 5% probability that the actual change in portfolio value will be greater than the calculated VaR value over the holding period. We currently use a 1-day holding period to evaluate our VaR exposure, and we calculate VaR based on the variance-covariance technique. Additionally, our calculation requires us to make a number of assumptions, regarding matters such as prices, volatilities, and positions. Our VaR may not be comparable to a similarly titled measure of another company because, although VaR is a common metric in the energy industry, there are no established industry standards for calculating VaR or for the assumptions underlying such calculations.

Retail Energy Operations SouthStar's use of derivatives is governed by a risk management policy, created and monitored by its risk management committee, which prohibits the use of derivatives for speculative purposes. A 95% confidence interval is used to evaluate its VaR. The following table provides the quarterly average on SouthStar's 1-day holding period VaR for the three and six months ended June 30, 2006 and 2005.

Three months ended June 30

In millions	**1-day**
Avg. 2006	$0.1
Avg. 2005	$0.1

Six months ended June 30

In millions	**1-day**
Avg. 2006	$0.1
Avg. 2005	$0.1

SouthStar generates operating margin from the active management of storage positions through a variety of hedging transactions and derivative instruments aimed at managing exposures arising from changing commodity prices. SouthStar uses these hedging instruments to lock in economic margins (as spreads between wholesale and retail commodity prices widen between periods) and thereby minimize its exposure to declining operating margins.

Wholesale Services This segment routinely utilizes various types of financial and other instruments to mitigate certain commodity price risks inherent in the natural gas industry. These instruments include a variety of exchange-traded and over-the-counter energy contracts, such as forward contracts, futures contracts, options contracts and financial swap agreements. The following table includes the fair values and average values of our energy marketing and risk management assets and liabilities as of June 30, 2006, December 31, 2005 and June 30, 2005. We base the average values on monthly averages for the six months ended June 30, 2006 and 2005.

	Average values at June 30,	
In millions	2006	2005
Asset	$83	$40
Liability	39	30

		Fair Values at	
In millions	June 30, 2006	Dec. 31, 2005	June 30, 2005
Asset	$93	$97	$50
Liability	39	110	42

Sequent's open exposure is managed in accordance with established policies that limit market risk and require daily reporting of potential financial exposure to senior management, including the chief risk officer. Because Sequent generally manages physical gas assets and economically protects its positions by hedging in the futures markets, its open exposure is generally immaterial, permitting Sequent to operate within relatively low VaR limits. Sequent employs daily risk testing, using both VaR and stress testing, to evaluate the risks of its open positions.

Sequent's management actively monitors open commodity positions and the resulting VaR. Sequent continues to maintain a relatively matched book, where its total buy volume is close to sell volume. Based on a 95% confidence interval and employing a 1-day holding period for all positions, Sequent's portfolio of positions for the three and six months ended June 30, 2006 and 2005 had the following VaRs.

	Three months ended June 30,	
In millions	2006	2005
Period end	$1.3	$0.1
Average	1.5	0.1
High	2.5	0.3
Low (1)	0.8	0.0

In millions	Six months ended June 30, 2006	2005
Period end	$1.3	$0.1
Average	1.2	0.1
High	2.5	0.4
Low (1)	0.7	0.0

(1) $0.0 values represent amounts less than $0.1 million.

During most of 2005 and the first six months of 2006, Sequent experienced increases in its high, average and period end 1-day VaR amounts compared to prior periods. These increases were directly associated with higher prices and related price volatility created by the Gulf Coast hurricanes during the third quarter of 2005 and their lingering effects through the fourth quarter of 2005 and the first six months of 2006. In addition, Sequent has entered into additional storage and transportation positions, some of which are longer dated and are not fully hedged due to a lack of liquidity in certain markets for the future periods. As a result, these positions increase our reported VaR amounts.

Sequent has refined the methodology associated with its VaR calculation to incorporate dynamic volatility factors and to exclude interruptible transportation positions. These changes had somewhat offsetting effects as the dynamic volatility factors increased our VaR and the exclusion of interruptible transportation positions reduced our VaR. This new methodology was applied on a prospective basis during the second quarter of 2006. While not considered material, Sequent's VaR amounts increased compared to prior periods as its calculation is now more sensitive to market volatility and the relative level of risk associated with increased storage and transportation positions. Due to the dynamic nature of measuring VaR, Sequent will continually evaluate the components of its VaR calculation and will make refinements as deemed necessary.

Interest Rate Risk

Interest rate fluctuations expose our variable-rate debt to changes in interest expense and cash flows. Our policy is to manage interest expense using a combination of fixed-rate and variable-rate debt. To facilitate the achievement of desired fixed-rate to variable-rate debt ratios, AGL Capital entered into interest rate swaps whereby it agreed to exchange, at specified intervals, the difference between fixed and variable amounts calculated by reference to agreed-on notional principal amounts. These swaps are designated to hedge the fair values of $100 million of the $300 million principal amount of senior notes due in 2011.

In the third quarter of 2005 and the second quarter of 2006, in anticipation of our $175 million senior notes offering in June 2006, we entered into treasury lock derivative agreements to hedge our exposure to increases in interest rates. We received an $11 million settlement payment from our counterparties, which we will amortize over the next 10 years through interest expense. These derivatives reduced the annual interest rate on our 6.375% senior notes by approximately 60 basis points.

Credit Risk

Wholesale Services Sequent has established credit policies to determine and monitor the creditworthiness of counterparties, as well as the quality of pledged collateral. Sequent also utilizes master netting agreements whenever possible to mitigate exposure to counterparty credit risk. When Sequent is engaged in more than one outstanding derivative transaction with the same counterparty and it also has a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of Sequent's credit risk. Sequent also uses other netting agreements with certain counterparties with whom it conducts significant transactions.

Master netting agreements enable Sequent to net certain assets and liabilities by counterparty. Sequent also nets across product lines and against cash collateral, provided the master netting and cash collateral agreements include such provisions. Additionally, Sequent may require counterparties to pledge additional collateral when deemed necessary. Sequent conducts credit evaluations and obtains appropriate internal approvals for its counterparty's line of credit before any transaction with the counterparty is executed. In most cases, the counterparty must have a minimum long-term debt rating of Baa3 from Moody's and BBB- from S&P. Generally, Sequent requires credit enhancements by way of guaranty, cash deposit or letter of credit for transactions with counterparties that do not meet the minimum ratings threshold.

Sequent, which provides services to marketers and utility and industrial customers, also has a concentration of credit risk as measured by its 30-day receivable exposure plus forward exposure. As of June 30, 2006, Sequent's top 20 counterparties represented approximately 59% of the total counterparty exposure of $258 million, derived by adding together the top 20 counterparties' exposures and dividing by the total of Sequent's counterparties' exposures.

As of June 30, 2006, Sequent's counterparties, or the counterparties' guarantors, had a weighted average S&P equivalent credit rating of A-, which is consistent with the prior year. The S&P equivalent credit rating is determined by a process of converting the lower of the S&P or Moody's ratings to an internal rating ranging from 9 to 1, with 9 being equivalent to AAA/Aaa by S&P and Moody's and 1 being D or Default by S&P and Moody's. A counterparty that does not have an external rating is assigned an internal rating based on the strength of the financial ratios of that counterparty.

To arrive at the weighted average credit rating, each counterparty's assigned internal rating is multiplied by the counterparty's credit exposure and summed for all counterparties. That sum is divided by the aggregate total counterparties' exposures, and this numeric value is then converted to an S&P equivalent. The following table shows Sequent's commodity receivable and payable positions as of June 30, 2006, December 31, 2005 and June 30, 2005.

In millions	Jun. 30, 2006	Dec. 31, 2005	Jun. 30, 2005
Gross receivables			
Receivables with netting agreements in place:			
Counterparty is investment grade	$305	$462	$262
Counterparty is non-investment grade	23	66	58
Counterparty has no external rating	65	113	66
Receivables without netting agreements in place:			
Counterparty is investment grade	8	34	10
Counterparty is non-investment grade	-	-	-
Counterparty has no external rating	-	-	-
Amount recorded on balance sheet	$401	$675	$396
Gross payables			
Payables with netting agreements in place:			
Counterparty is investment grade	$223	$456	$255
Counterparty is non-investment grade	57	56	62
Counterparty has no external rating	139	255	107
Payables without netting agreements in place:			
Counterparty is investment grade	11	4	42
Counterparty is non-investment grade	-	-	-
Counterparty has no external rating	1	4	1
Amount recorded on balance sheet	$431	$775	$467

Sequent has certain trade and credit contracts that have explicit rating trigger events in case of a credit rating downgrade. These rating triggers typically give counterparties the right to suspend or terminate credit if our credit ratings are downgraded to non-investment grade status. Under such circumstances, Sequent would need to post collateral to continue transacting business with some of its counterparties. Posting collateral would have a negative effect on our liquidity. If such collateral were not posted, Sequent's ability to continue transacting business with these counterparties would be impaired. If at June 30, 2006 Sequent's credit ratings had been downgraded to non-investment grade status, the required amounts to satisfy potential collateral demands under such agreements between Sequent and its counterparties would have totaled $14 million.

Item 4. Controls and Procedures

(a) ***Evaluation of disclosure controls and procedures*.** Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of our disclosure controls and procedures, as such term is defined in Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act), as of June 30, 2006, the end of the period covered by this report. Based on this evaluation, our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were effective as of June 30, 2006 in providing a reasonable level of assurance that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods in SEC rules and forms, including a reasonable level of assurance that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our principal executive officer and our principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

(b) ***Changes in internal controls over financial reporting*.** There were no changes in our internal control over financial reporting during our most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II -- OTHER INFORMATION

Item 1. Legal Proceedings

Teamsters Local 528 represented approximately 300 Atlanta Gas Light employees under a collective bargaining agreement that was to expire on March 23, 2006. Atlanta Gas Light and the Teamsters were not able to finalize a new collective bargaining agreement prior to its expiration and, on March 23, 2006, the Teamsters disclaimed interest in representing the bargaining unit. On March 24, 2006, the International Brotherhood of Electrical Workers (IBEW) Local 84 filed a representation petition with the National Labor Relations Board (NLRB) seeking an election to certify it as the representative of a bargaining unit of Atlanta Gas Light employees. The NLRB conducted a representation election on May 4 and 5, 2006, and the majority of employees who voted rejected the representation request. Consequently, these Atlanta Gas Light employees are no longer represented by a bargaining unit and now fall under our standard human resources pay and benefit plans and policies. Another representation election involving the IBEW or another union cannot be held among this group of employees for one calendar year.

The nature of our business ordinarily results in periodic regulatory proceedings before various state and federal authorities and litigation incidental to the business. For information regarding pending federal and state regulatory matters, see "Results of Operations – Distribution Operations" contained in Item 2 of Part I under the caption "Management's Discussion and Analysis of Financial Condition and Results of Operations." With regard to other legal proceedings, we are a party, as both plaintiff and defendant, to a number of other suits, claims and counterclaims on an ongoing basis. Management believes that the outcome of all such other litigation in which it is involved will not have a material adverse effect on our consolidated financial statements.

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

The following table presents information about our purchases of our common stock during the second quarter of 2006:

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (1)	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
April 2006	103,106 (1) (2)	$35.40	103,000	7,811,500
May 2006	118,167 (1) (2)	35.45	117,750	7,693,750
June 2006	111,235 (1) (2)	36.60	111,000	7,582,750
Total second quarter	**332,508**	**$35.82**	**331,750**	**7,582,750**

(1) On February 3, 2006, we announced that our Board of Directors authorized a plan to repurchase up to 8 million shares of our outstanding common stock over a five year period.

(2) Pursuant to our stock-based compensation plans, participants may surrender shares of our common stock as payment of applicable tax withholding obligations in connection with the vesting of shares of restricted stock and/or the exercise of stock options. These shares are not repurchased pursuant to a publicly announced share repurchase program.

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

The annual meeting of shareholders was held in Atlanta, Georgia on May 3, 2006. Holders of an aggregate of 77,952,313 shares of our common stock at the close of business on February 24, 2006 were entitled to vote at the meeting, of which 69,479,273 or 89.13% of the eligible voting shares were represented in person or by proxy. At the annual meeting, our shareholders were presented with three proposals, as set forth in our proxy statement. Our shareholders voted as follows:

Proposal 1

Election of Directors	For	Withheld
Charles R. Crisp	69,036,291	442,981
Wyck A. Knox, Jr.	65,259,789	4,219,483
Dennis M. Love	68,935,793	543,480
Dean R. O'Hare	69,058,553	420,719
John W. Somerhalder II	69,055,324	423,948
Henry C. Wolf	67,207,086	2,278,186

The term of office of each of the following directors continued after the meeting: Thomas D. Bell, Jr., Michael J. Durham, Arthur E. Johnson, James A. Rubright, D. Raymond Riddle, Felker W. Ward, Jr. and Bettina M. Whyte.

Proposal 2

Approval of the AGL Resources Inc. 2006 Non-Employee Directors Equity Compensation Plan.

For	51,698,242
Against	5,659,968
Abstain	584,962
Broker Non Votes	11,536,099

Proposal 3

Ratification of the appointment of PricewaterhouseCoopers LLP as our independent public accounting firm for 2006.

For	68,949,869
Against	259,826
Abstain	269,576
Broker Non Votes	-

Item 5. Other Information

As disclosed in Item 4 above, the shareholders of the Company approved the AGL Resources Inc. 2006 Non-Employee Directors Equity Compensation Plan at the annual meeting of shareholders held on May 3, 2006. A description of the material terms of the plan was contained in the Company's proxy statement for the annual meeting, which was filed with the SEC on March 20, 2006. A copy of the plan is incorporated by reference into this report as Exhibit 10.1.

Item 6. Exhibits

3.1 Amended and Restated Articles of Incorporation filed November 2, 2005 with the Secretary of State of the state of Georgia (incorporated herein by reference to Exhibit 3.1 of AGL Resources Inc. Current Report on Form 8-K dated November 2, 2005).

3.2 Bylaws, as amended on October 29, 2003 (incorporated herein by reference to Exhibit 3.2 of AGL Resources Inc. Annual Report on Form 10-K for the fiscal year ended December 31, 2003).

4.1 Indenture dated February, 2001 among AGL Capital Corporation, AGL Resources Inc. and The Bank of New York, as Trustee (incorporated herein by reference to Exhibit 4.2 of AGL Resources Inc. Registration Statement on From S-3, filed on September 17, 2001, No. 333-69500).

4.2 Specimen AGL Capital Corporation 6.375% Senior Notes due 2016 (incorporated herein by reference to Exhibit 4.1 of AGL Resources Inc. Current Report on Form 8-K dated June 27, 2006).

4.3 Form of Guarantee of AGL Resources Inc. dated as of June 30, 2006 regarding the AGL Capital Corporation 6.375% Senior Notes due 2016 (incorporated herein by reference to Exhibit 4.3 of AGL Resources Inc. Current Report on Form 8-K dated June 27, 2006).

10.1 AGL Resources Inc. 2006 Non-Employee Directors Equity Compensation Plan (incorporated herein by reference to Annex C of the AGL Resources Inc. Proxy Statement for the Annual Meeting of Shareholders held May 3, 2006 filed with the SEC on March 20, 2006).

31.1 Certification of John W. Somerhalder II pursuant to Rule 13a – 14(a)

31.2 Certification of Andrew W. Evans pursuant to Rule 13a – 14(a)

32.1 Certification of John W. Somerhalder II pursuant to 18 U.S.C. Section 1350

32.2 Certification of Andrew W. Evans pursuant to 18 U.S.C. Section 1350

SIGNATURE

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.

AGL RESOURCES INC.
(Registrant)

Date: August 2, 2006

/s/ Andrew W. Evans
Executive Vice President and Chief Financial Officer