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

FORM 10-Q

(Mark One)
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Quarterly Period Ended June 30, 2004

OR

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

For the transition period from to

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)
(Zip Code)

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 X No __

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes X 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 23, 2004
Common Stock, $5.00 Par Value	64,946,102

AGL RESOURCES INC.

Form 10-Q

For the Quarterly Period Ended June 30, 2004

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GLOSSARY OF KEY TERMS

AGLC	Atlanta Gas Light Company
AGL Capital	AGL Capital Corporation
AGL Networks	AGL Networks, LLC
AGSC	AGL Services Company
CGC	Chattanooga Gas Company
Corporate	Nonoperating segment, which includes AGSC, AGL Capital and Pivotal
Credit Facility	Credit agreement supporting our commercial paper program
Distribution operations	Segment that includes AGLC, VNG and CGC
EBIT	Earnings before interest and taxes, a non-GAAP measure that includes operating income, other income, equity in SouthStar's income in 2003, donations, minority interest in 2004 and gain on sales of assets. Excludes interest and tax expense; as an indicator of our operating performance, EBIT should not be considered an alternative to, or more meaningful than, operating income or net income as determined in accordance with GAAP
Energy investments	Segment that consists primarily of SouthStar, US Propane (and its investment in Heritage) and AGL Networks
ERC	Environmental response costs
FASB	Financial Accounting Standards Board
FIN	FASB Interpretation Number
GAAP	Accounting principles generally accepted in the United States of America
GPSC	Georgia Public Service Commission
LNG	Liquefied natural gas
Marketers	Georgia Public Service Commission-certificated marketers selling retail natural gas in Georgia
Medium-Term notes	Notes issued by AGLC scheduled to mature in 2004 through 2027 bearing interest rates ranging from 6.55% to 8.7%
MGP	Manufactured gas plant
NYMEX	New York Mercantile Exchange, Inc.
Operating margin	A non-GAAP measure of income, calculated as revenues minus cost of gas, that excludes operation and maintenance expense, depreciation and amortization, taxes other than income taxes, and the gain on the sale of our Caroline Street campus; these items are included in our calculation of operating income as reflected in our statements of consolidated income; operating margin should not be considered an alternative to, or more meaningful than, operating income or net income as determined in accordance with GAAP
PGA	Purchased gas adjustment
Pivotal	Pivotal Energy Development
PRP	Pipeline replacement program
PUHCA	Public Utility Holding Company Act of 1935, as amended
RMC	AGL Resources' Risk Management Committee
SEC	Securities and Exchange Commission
Sequent	Sequent Energy Management, L.P.
Senior notes	Notes issued by AGL Capital scheduled to mature in 2011 through 2013 bearing interest rates ranging from 4.45% to 7.125%
SFAS	Statement of Financial Accounting Standards
SouthStar	SouthStar Energy Services LLC
Trust Preferred Securities	Trust preferred securities subject to mandatory redemption
Trusts	AGL Capital Trust I and AGL Capital Trust II
US Propane	US Propane LP
VNG	Virginia Natural Gas, Inc.
VSCC	Virginia State Corporation Commission
Wholesale services	Segment that consists primarily of Sequent
WNA	Weather normalization adjustment

REFERENCED ACCOUNTING STANDARDS

APB 25	Accounting Principles Board Opinion No. 25, “Accounting for Stock Issued to Employees”
ARB 51	Accounting Research Bulletin No. 51, “Consolidated Financial Statements”
EITF 99-02	Emerging Issues Task Force Issue No. 99-02, “Accounting for Weather Derivatives”
EITF 02-03	Emerging Issues Task Force Issue No. 02-03, “Issues Involved in Accounting for Contracts under EITF Issue No. 98-10, ‘Accounting for Contracts Involved in Energy Trading and Risk Management Activities’”
FIN 46 & FIN 46R	FASB Interpretation No. 46, “Consolidation of Variable Interest Entities”
FSP 106-1	FASB Staff Position No. 106-1, “Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003”
FSP 106-2	FASB Staff Position No. 106-2, “Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003”
SFAS 66	SFAS No. 66, “Accounting for Sales of Real Estate”
SFAS 71	SFAS No. 71, “Accounting for the Effects of Certain Types of Regulation”
SFAS 123	SFAS No. 123, “Accounting for Stock-Based Compensation”
SFAS 133	SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities”
SFAS 149	SFAS No. 149, “Amendment of Statement 133 on Derivative Instruments and Hedging Activities”

Item 1. Financial Statements

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

In millions	June 30, 2004	December 31, 2003	June 30, 2003
Current assets			
Cash and cash equivalents	$54	$17	$3
Receivables (less allowance for uncollectible accounts of $17 million at June 30, 2004, $2 million at December 31, 2003 and $3 million at June 30, 2003)	414	394	276
Unbilled revenues	42	40	5
Inventories	259	210	168
Unrecovered environmental response costs – current	26	24	24
Unrecovered pipeline replacement program costs – current	24	22	18
Energy marketing and risk management assets	21	13	12
Other	10	22	6
Total current assets	850	742	512
Property, plant and equipment			
Property, plant and equipment	3,476	3,402	3,390
Less accumulated depreciation	1,067	1,050	1,165
Property, plant and equipment-net	2,409	2,352	2,225
Deferred debits and other assets			
Unrecovered pipeline replacement program costs	381	410	437
Goodwill	177	177	176
Unrecovered environmental response costs	141	155	155
Investments in Trusts	10	-	-
Unrecovered postretirement benefit costs	9	9	11
Investments in equity interests	-	101	112
Other	33	26	25
Total deferred debits and other assets	751	878	916
Total assets	$4,010	$3,972	$3,653

See Notes to Condensed Consolidated Financial Statements (Unaudited).

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

In millions	June 30, 2004	December 31, 2003	June 30, 2003
Current liabilities			
Payables	$535	$403	$387
Short-term debt	161	306	147
Accrued pipeline replacement program costs – current	90	82	67
Accrued expenses	53	54	60
Accrued environmental response costs – current	37	40	48
Current portion of long-term debt	34	77	95
Energy marketing and risk management liabilities	11	17	11
Other	95	69	71
Total current liabilities	1,016	1,048	886
Accumulated deferred income taxes	413	376	344
Long-term liabilities			
Accrued pipeline replacement program costs	285	323	365
Accumulated removal costs	104	102	-
Accrued postretirement benefit costs	51	51	51
Accrued pension obligations	27	39	67
Accrued environmental response costs	25	43	38
Other	13	11	9
Total long-term liabilities	505	569	530
Deferred credits	74	77	71
Commitments and contingencies (Note 7)			
Minority interest	29	-	-
Capitalization			
Senior and Medium-Term notes	728	731	697
Notes payable to Trusts	234	-	-
Subsidiaries' obligated mandatorily redeemable preferred securities	-	225	228
Total long-term debt	962	956	925
Common shareholders' equity, $5 par value; 750,000,000 shares authorized	1,011	946	897
Total capitalization	1,973	1,902	1,822
Total liabilities and capitalization	$4,010	$3,972	$3,653

See Notes to Condensed Consolidated Financial Statements (Unaudited).

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED STATEMENTS OF CONSOLIDATED INCOME
FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2004 AND 2003
(UNAUDITED)

	Three months		Six Months	
In millions, except per share amounts	2004	2003	2004	2003
Operating revenues	$294	$187	$945	$539
Operating expenses				
Cost of gas	129	46	522	194
Operation and maintenance expenses	81	70	174	142
Depreciation and amortization	24	23	48	45
Taxes other than income	7	7	15	15
Total operating expenses	241	146	759	396
Operating income	53	41	186	143
Equity in earnings of SouthStar	-	10	-	24
Other income (loss)	1	(2)	2	-
Interest expense	(16)	(18)	(32)	(38)
Minority interest	(3)	-	(14)	-
Earnings before income taxes	35	31	142	129
Income taxes	14	12	55	50
Income before cumulative effect of change in accounting principle	21	19	87	79
Cumulative effect of change in accounting principle, net of taxes	-	-	-	(8)
Net income	$21	$19	$87	$71
Basic earnings per common share				
Income before cumulative effect of change in accounting principle	$0.34	$0.30	$1.35	$1.27
Cumulative effect of change in accounting principle	-	-	-	(0.13)
Basic earnings per common share	$0.34	$0.30	$1.35	$1.14
Diluted earnings per common share				
Income before cumulative effect of change in accounting principle	$0.33	$0.29	$1.33	$1.26
Cumulative effect of change in accounting principle	-	-	-	(0.13)
Diluted earnings per common share	$0.33	$0.29	$1.33	$1.13
Weighted-average number of common shares outstanding				
Basic	64.8	63.5	64.7	61.9
Diluted	65.6	64.2	65.5	62.4

See Notes to Condensed Consolidated Financial Statements (Unaudited).

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY
FOR THE SIX MONTHS ENDED JUNE 30, 2004
(UNAUDITED)

	Common Stock		Premium on		Other		
In millions, except per share amounts	Shares	Amount	common shares	Earnings reinvested	Comprehensive income	Treasury stock	Total
Balance as of Dec. 31, 2003	64.5	$322	$326	$338	($40)	-	$946
Comprehensive income:							
Net income	-	-	-	87	-	-	87
Total comprehensive income							87
Dividends on common shares ($0.57 per share)	-	-	-	(37)	-	-	(37)
Benefit, stock compensation, dividend reinvestment and share purchase plans ($28.86 weighted average price per share)	0.4	3	12	-	-	-	15
Balance as of June 30, 2004	64.9	$325	$338	$388	($40)	$-	$1,011

See Notes to Condensed Consolidated Financial Statements (Unaudited).

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASHFLOWS
FOR THE SIX MONTHS ENDED JUNE 30, 2004 AND 2003
(UNAUDITED)

In millions	2004	2003
Cash flows from operating activities		
Net income	$87	$71
Adjustments to reconcile net income to net cash flow provided by operating activities		
Depreciation and amortization	48	45
Cumulative effect of accounting change	-	13
Deferred income taxes	37	24
Equity in earnings of unconsolidated affiliates	(1)	(24)
Minority interest	14	-
Changes in certain assets and liabilities		
Receivables	105	98
Payables	74	45
Inventories	(21)	(50)
Other	1	(17)
Net cash flow provided by operating activities	344	205
Cash flows from investing activities		
Property, plant and equipment expenditures	(104)	(77)
Purchase of Dynegy Inc.'s 20% ownership interest in SouthStar	-	(20)
Sale of ownership interest in US Propane	31	-
Other	1	13
Net cash flow used in investing activities	(72)	(84)
Cash flows from financing activities		
Payments and borrowings of short-term debt, net	(151)	(241)
Payments of Medium-Term notes	(49)	-
Dividends paid on common shares	(37)	(32)
Distribution to minority interest	(14)	-
Equity offering	-	137
Other	16	10
Net cash flow used in financing activities	(235)	(126)
Net increase (decrease) in cash and cash equivalents	37	(5)
Cash and cash equivalents at beginning of period	17	8
Cash and cash equivalents at end of period	$54	$3
Cash paid during the period for		
Interest (net of allowance for funds used during construction)	$24	$30
Income taxes	$22	$1

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). We believe, however, that our disclosures are adequate and the information presented is not misleading.

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 for the year ended December 31, 2003, filed with the SEC on February 6, 2004.

Due to the seasonal nature of our business, the results of operations for the three and six months ended June 30, 2004 and the June 30, 2004, December 31, 2003 and June 30, 2003 balance sheets are not necessarily indicative of the results of operations to be expected for any other interim period or for the year ending December 31, 2004. For a glossary of key terms and referenced accounting standards, see pages three and four of this filing.

Basis of Presentation

Our condensed consolidated financial statements as of and for the periods ended June 30, 2004 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 to conform to the current period presentation. The December 31, 2003 balance sheet amounts are derived from our audited financial statements.

Our condensed consolidated financial statements include the accounts of SouthStar Energy Services LLC (SouthStar), a variable interest entity of which we are the primary beneficiary. Previously, we accounted for our 70% non-controlling financial ownership interest in SouthStar using the equity method of accounting. Under the equity method, our ownership interest in SouthStar was reported as an investment within our consolidated balance sheet, and our share of SouthStar’s earnings was reported in our condensed consolidated statement of income as a component of other income. We utilize the equity method to account for and report investments where we exercise significant influence but not control and where we are not the primary beneficiary as defined by FIN 46. Our equity method investments generally include entities where we have a 20% to 50% voting interest.

In January 2003, the Financial Accounting Standards Board (FASB) issued Interpretation No. 46, “Consolidation of Variable Interest Entities” (FIN 46), which was effective for our December 31, 2003 consolidated financial statements. FIN 46 was subsequently revised in December 2003 (FIN 46R). FIN 46R clarifies the application of Accounting Research Bulletin No. 51, “Consolidated Financial Statements” to certain entities in which equity investors do not have the characteristics of a controlling financial interest. FIN 46R also defines a variable interest entity, and provides guidance for determining when a business enterprise should consolidate the results of a variable interest entity.

During the first quarter effective January 1, 2004, we adopted FIN 46R resulting in the consolidation of SouthStar's accounts in our condensed consolidated financial statements; and the deconsolidation of the accounts related to our Trust Preferred Securities. For more discussion on FIN 46R and the impact of its adoption on our condensed consolidated financial statements, see Note 2, Recent Accounting Pronouncements.

Stock-based Compensation

We have several stock-based employee compensation plans and we account for these plans under the recognition and measurement principles of Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" (APB 25) and Statement of Financial Accounting Standard No. 123, "Accounting for Stock-Based Compensation" (SFAS 123). For our stock option plans, we generally do not reflect stock-based employee compensation cost in net income, as options granted under those plans had an exercise price equal to the market value of the underlying common stock on the date of grant. For our stock appreciation rights, we reflect stock-based employee compensation cost based on the fair value of our common stock at the balance sheet date, since these awards constitute a variable plan under APB 25.

The following table illustrates the effect on our net income and earnings per share for the three and six months ended June 30, 2004 and 2003 as if we had applied the optional fair value recognition provisions of SFAS 123:

	Three months		Six months	
In millions, except per share amounts	2004	2003	2004	2003
Net income, as reported	$21	$19	$87	$71
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	$21	$19	$86	$71
Earnings per share:				
Basic-as reported	$0.34	$0.30	$1.35	$1.14
Basic-pro-forma	$0.34	$0.30	$1.33	$1.14
Diluted-as reported	$0.33	$0.29	$1.33	$1.13
Diluted-pro-forma	$0.33	$0.29	$1.31	$1.13

Comprehensive Income

Our comprehensive income includes net income and 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 and minimum pension liability adjustments. For the six months ended June 30, 2004 our comprehensive income increased as a result of the fair value of derivatives at SouthStar in the amount of $1 million and a similar offsetting decrease due to the sale of our remaining investment units related to US Propane LP. As a result, our comprehensive income for June 30, 2004 was equal to net income. For the six months ended June 30, 2003 our comprehensive income was equal to net income.

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 performance units and stock options. The future issuance of shares underlying the performance 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. There were no anti-dilutive items. The following table shows the calculation of our diluted shares for the three and six months ended June 30, 2004 and 2003, assuming performance units currently earned under the plan ultimately vest, and stock options currently exercisable at prices below the average market prices are exercised:

	Three months		Six months	
In millions	2004	2003	2004	2003
Denominator for basic earnings per share (daily weighted-average shares outstanding)	64.8	63.5	64.7	61.9
Assumed exercise of performance units and stock options	0.8	0.7	0.8	0.5
Denominator for diluted earnings per share	65.6	64.2	65.5	62.4

Note 2
Recent Accounting Pronouncements

FIN 46

FIN 46 requires the primary beneficiary of a variable interest entity's activities to consolidate the variable interest entity. The primary beneficiary is the party that absorbs a majority of the expected losses and/or receives a majority of the expected residual returns of the variable interest entity's activities.

In December 2003, the FASB revised FIN 46, delaying the effective dates for certain entities created before February 1, 2003, and making other amendments to clarify application of the guidance. For potential variable interest entities other than any special purpose entities, FIN 46R was required to be applied no later than the end of the first fiscal year or interim reporting period ending after March 15, 2004.

FIN 46R may be applied prospectively with a cumulative-effect adjustment as of the date it is first applied, or by restating previously issued financial statements with a cumulative-effect adjustment as of the beginning of the first year restated. FIN 46R also requires certain disclosures of an entity's relationship with variable interest entities. We adopted FIN 46R as of March 31, 2004.

Notes payable to Trusts and Trust Preferred Securities In June 1997 and March 2001, we established AGL Capital Trust I and AGL Capital Trust II (Trusts) to issue our Trust Preferred Securities. The Trusts are considered to be special purpose entities under FIN 46 and FIN 46R since our equity in the Trusts is not considered to be sufficient to allow the Trusts to finance their own activities and our equity investment is not considered to be at risk since the equity amounts were financed by the Trusts.

Under FIN 46 (prior to the revision in FIN 46R), we concluded that we were the primary beneficiary of the Trusts because the Trust Preferred Securities are publicly traded, widely held, and no one party would absorb a majority of any expected losses of the Trusts. In addition, our loan agreements with the Trusts include call options allowing us to capture the benefits of declining interest rates since the options enable us to call the preferred securities at par, giving us the ability to capture the majority of the residual returns in the Trusts. Accordingly, at December 31, 2003, the accounts of the Trusts were included in our consolidated financial statements.

The revisions in FIN 46R included specific guidance that instruments such as the call options included in our loan agreements with the Trusts do not constitute variable interests, and should not be considered in the determination of the primary beneficiary. As a result, as of January 1, 2004 we were required to exclude the accounts of the Trusts from our consolidated financial statements upon our adoption of FIN 46R and to classify amounts payable to the Trusts as "Notes Payable to Trusts" within capitalization in our condensed consolidated balance sheets as of June 30, 2004.

The impact of deconsolidation of the Trusts is that we have included in our condensed consolidated balance sheets at June 30, 2004, an asset of approximately $10 million representing our investment in the Trusts, and a note payable to the Trusts totaling approximately $232 million, which is net of an interest rate swap of $2 million, and removed $222 million related to the Trust Preferred Securities issued by the Trusts. The notes payable represent the loan payable to fund our investments in the Trusts of $10 million and the amounts due to the Trusts from the proceeds received from their issuances of Trust Preferred Securities of $222 million.

SouthStar SouthStar is a joint venture formed in 1998 by our subsidiary, Georgia Natural Gas Company, Piedmont Natural Gas Company, Inc. (Piedmont) and Dynegy Inc. (Dynegy) to market natural gas and related services to retail customers, principally in Georgia. On March 11, 2003, we purchased Dynegy's 20% ownership interest in a transaction that for accounting purposes had an effective date of February 18, 2003. We currently own a non-controlling 70% financial interest in SouthStar and Piedmont owns the remaining 30%. Our 70% interest is non-controlling because all significant management decisions require approval by both owners.

On March 29, 2004 we executed an amended and restated partnership agreement with Piedmont. This amended and restated partnership agreement calls for SouthStar's future earnings starting in 2004 to be allocated 75% to our subsidiary and 25% to Piedmont. For all periods prior to February 18, 2003, SouthStar's earnings have been allocated to us based upon our ownership interests in those periods of 50%. SouthStar, which operates under the trade name Georgia Natural Gas, competes with other energy marketers, including Marketers in Georgia, to provide natural gas and related services to customers in Georgia and the Southeast.

As of December 31, 2003, we did not consolidate SouthStar in our financial statements because it did not meet the definition of a variable interest entity under FIN 46. FIN 46R added the following conditions for determining whether an entity was a variable interest entity:

- the voting rights of some investors are not proportional to their obligations to absorb the expected losses of the entity, their rights to receive the expected residual returns of the entity, or both, and
- substantially all of the entity's activities (for example purchasing products and additional capital) either involve or are conducted on behalf of an investor that has disproportionately fewer voting rights.

We determined that SouthStar is a variable interest entity as defined in FIN 46R 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, and
- SouthStar obtains substantially all of its transportation capacity for delivery of natural gas through our wholly owned subsidiary, Atlanta Gas Light Company (AGLC).

Consequently, as of January 1, 2004, we consolidated all of SouthStar's accounts with our subsidiaries' accounts and eliminated any intercompany balances between segments. We recorded Piedmont's portion of SouthStar's earnings as a minority interest in our condensed consolidated statements of income, and we recorded Piedmont's portion of SouthStar's capital as a minority interest on our condensed consolidated balance sheet.

FASB Staff Position 106-2 On May 19, 2004, the FASB issued FSP 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," (FSP 106-2) which supersedes FSP 106-1 and is effective for the first interim or annual reporting period beginning after June 15, 2004, or July 1, 2004 for us. The guidance in FSP 106-2 related to the accounting for the federal subsidy applies only to the sponsor of a single-employer defined benefit postretirement health care plan for which (a) the employer has concluded that prescription drug benefits available under the plan to some or all participants for some or all future years are "actuarially equivalent" to Medicare Part D and thus qualify for the subsidy under the Medicare Prescription Drug Act and (b) the expected federal subsidy will offset or reduce the employer's share of the cost of the underlying postretirement prescription drug coverage on which the federal subsidy is based. FSP 106-2 also provides guidance for the disclosures about the effects of the subsidy for an employer that sponsors a postretirement health care benefit plan that provides prescription drug coverage but for which the employer has not yet been able to determine actuarial equivalency.

Effective July 2, 2004 we amended our Defined Benefit Health Care and Life Insurance Plan (Defined Plan) to no longer offer prescription drug benefits to retirees age 65 and older after January 1, 2006. As a result, FSP 106-2 will not have an impact on our accounting for our Defined Plan.

Note 3
Risk Management

Our risk management activities are monitored by the Risk Management Committee (RMC). The RMC is comprised of senior officers charged with the review and enforcement of our risk management policies. Our risk management policies limit the use of derivative financial instruments and physical transactions within pre-defined 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

Interest Rate Swaps

To maintain an effective capital structure, it is our policy to borrow funds using a mix of fixed-rate and variable-rate debt. We have entered into interest rate swap agreements through our wholly owned subsidiary, AGL Capital Corporation (AGL Capital), for the purpose of hedging the interest rate risk associated with our fixed-rate and variable-rate debt obligations. We designated these interest rate swaps as fair value hedges and accounted for them using the "shortcut' method prescribed by Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133), which allows us to designate derivatives that hedge exposure to changes in the fair value of a recognized asset or liability. We record the gain or loss on fair value hedges in earnings in the period of change, together with the offsetting loss or gain on the hedged item attributable to the risk being hedged. The effect of this accounting is to reflect in earnings only that portion of the hedge that is ineffective in achieving offsetting changes in fair value.

Accordingly, we adjust the carrying value of each interest rate swap to its fair value at the end of each period, with an offsetting and equal adjustment to the carrying value of the debt securities whose fair value is being hedged. Consequently, our earnings are not affected negatively or positively with changes in fair value of the interest swaps each quarter.

In March 2004 we adjusted our fixed to variable-rate debt obligations and terminated an interest rate swap on $100 million of the principal amount of our 4.45% Senior Notes due 2013. Additionally, as of March 31, 2004 and in connection with the deconsolidation of the Trusts, we re-designated the interest rate swaps on the Trust Preferred Securities as a fair value hedge of our notes payable to the Trusts.

As of June 30, 2004, a notional principal amount of $175 million of these interest rate swap agreements effectively converted the interest expense associated with a portion of our Senior Notes and notes payable to the Trusts from fixed rates to variable rates based on an interest rate equal to the London Interbank Offered Rate (LIBOR), plus a spread determined at the swap date. Our interest rate swaps consist of the following:

- $100 million principal amount of 7.125% Senior Notes due 2011. We pay floating interest each January 14 and July 14 at six-month LIBOR plus 3.4%. The effective variable interest rate at June 30, 2004 was 4.6%, an increase of 0.1% from December 31, 2003. These interest rate swaps expire January 14, 2011, unless terminated earlier.
- $75 million principal amount of 8.0% notes payable to Trusts due 2041. We pay floating interest rates each February 15, May 15, August 15 and November 15 at three-month LIBOR plus 1.315%. The effective interest rate at June 30, 2004 was 2.6%, an increase of 0.1% from December 31, 2003. These interest rate swaps expire May 15, 2041, unless terminated earlier.

The aggregate fair value of these interest rate swaps was recorded as a liability of $3 million at June 30, 2004 and $4 million at December 31, 2003 and an asset of $9 million at June 30, 2003.

Commodity-related derivative instruments

Sequent We are exposed to risks associated with changes in the market price of natural gas. Sequent Energy Management, L.P. (Sequent) uses derivative financial instruments to reduce our exposure to the risk of changes in the prices of natural gas. The fair value of these derivative financial instruments reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains or losses on open contracts. We use external market quotes and indices to value substantially all the financial instruments we utilize.

We attempt to mitigate substantially all the commodity price risk associated with Sequent's natural gas portfolio to lock in the economic margin at the time we enter into natural gas purchase transactions for our stored natural gas. We purchase natural gas for storage when the difference in the current market price we pay to buy natural gas plus the cost to store the natural gas is less than the market price we can receive in the future, resulting in a positive net profit margin. We use New York Mercantile Exchange (NYMEX) futures contracts to sell natural gas at that future price to substantially lock in the profit margin we will ultimately realize when the stored gas is actually sold. Those NYMEX futures contracts meet the definition of a derivative under SFAS 133 and are recorded at fair value in our condensed consolidated balance sheet, with changes in fair value recorded in earnings in the period of change. The purchase, storage and sale of natural gas are accounted for on an accrual basis rather than on the mark-to-market basis we utilize for the derivatives used to mitigate the commodity price risk associated with our storage portfolio. This difference in accounting will result in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated. We do not currently use hedge accounting under SFAS 133 to account for this activity.

Our commodity-related derivative financial instruments, which exclude interest rate swaps, had a weighted average maturity of 8 months based on volumes. At June 30, 2004, our commodity-related derivative financial instruments represented purchases (long) of 540 billion cubic feet (Bcf) with approximately 99% of these scheduled to mature in less than 2 years. In addition, our financial instruments included sales (short) of 555 Bcf with approximately 96% of these scheduled to mature in less than 2 years and the remaining 4% in 3-9 years. For the six months ended June 30, 2004 and 2003, excluding the cumulative effect of a change in an accounting principle in 2003 for the adoption of EITF 02-03, our unrealized gains were $15 million in 2004 and $6 million in 2003.

SouthStar The commodity-related derivative financial instruments (futures, options and swaps) used by SouthStar manage exposures arising from changing commodity prices. SouthStar's objective for holding these derivatives is to minimize this risk using the most effective methods to reduce or eliminate the impacts of these exposures. A significant portion of SouthStar's derivative transactions are designated as cash flow hedges under SFAS 133. Derivative gains or losses arising from cash flow hedges are recorded in other comprehensive income (OCI) and are reclassified into earnings in the same period as the settlement of the underlying hedged item. Any hedge ineffectiveness, defined as when the gains or losses on the hedging instrument do not perfectly offset the losses or gains on the hedged item, is recorded into earnings in the period in which it occurs. SouthStar currently has no hedge ineffectiveness. The remainder of SouthStar's derivative instruments does not meet the hedge criteria under SFAS 133. Therefore, changes in their fair value are recorded in earnings in the period of change.

At June 30, 2004, the fair value of these derivatives was reflected in our condensed consolidated financial statements as an asset of $2 million with a corresponding increase to OCI of $1 million. For the six months ended June 30, 2004, a loss of $1 million was reclassified to earnings from OCI related to instruments designated as hedges under SFAS 133 and a loss of $1 million was recognized on instruments not designated as hedges under SFAS 133 representing the change in fair value of those instruments during the period. No amounts were recorded to earnings related to hedge ineffectiveness. The maximum maturity of open positions is less than 2 years and represent purchases of 2 Bcf and sales of 3 Bcf, with approximately 97% scheduled to mature in less than one year.

Weather derivative contracts

SouthStar routinely enters into weather derivative contracts for hedging purposes in order to preserve margins in the event of warmer-than-normal weather in the winter months. SouthStar accounts for these contracts using the intrinsic value method under the guidelines of EITF 99-02, "Accounting for Weather Derivatives".

Concentration of Credit Risk

Distribution Operations AGLC has a concentration of credit risk for amounts billed for services and other costs to its customers, ten Marketers and poolers in Georgia. The credit risk exposure to Marketers varies seasonally, with the lowest exposure in the non-peak summer months and highest exposure in the peak winter months. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. These retail functions include customer service, billing, collections, and the purchase and sale of natural gas. The provisions of AGLC's tariff allow AGLC to obtain security support in an amount equal to a minimum of two times a Marketer's highest monthly bill.

Wholesale Services Sequent provides services to marketers, utility and industrial customers has a concentration of credit risk measured by 30-day receivable exposure plus forward exposure, which is highly concentrated in 20 of its counterparties. At June 30, 2004, Sequent's top 20 counterparties represented approximately 55% of the total counterparty credit exposure of $238 million, derived by adding the top 20 counterparties' exposures and dividing by the total of Sequent's counterparties' exposures.

Sequent has established credit policies to determine and monitor the creditworthiness of counterparties, as well as the quality of pledged collateral. When we are engaged in more than one outstanding derivative transaction with the same counterparty and we also have 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 our credit risk. Sequent also uses other netting agreements with certain counterparties with whom we conduct significant transactions.

Note 4
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." Our regulatory assets and liabilities, and associated liabilities for our unrecovered pipeline replacement program (PRP) costs and unrecovered environmental response costs (ERC), are summarized in the table below:

In millions	June 30, 2004	Dec. 31, 2003	June 30, 2003
Regulatory assets			
Unrecovered PRP costs	$405	$432	$455
Unrecovered ERC	167	179	179
Unrecovered postretirement benefit costs	9	9	11
Unrecovered seasonal rates (1)	-	11	-
Unamortized call premium (2)	6	4	-
Regulatory tax asset(2)	3	3	3
Other (3)	1	1	1
Total regulatory assets	$591	$639	$649
Regulatory liabilities			
Accumulated removal costs	$104	$102	$-
Deferred seasonal rates (4)	9	-	9
Unamortized investment tax credit (5)	18	19	20
Deferred PGA (4)	36	30	16
Regulatory tax liability (5)	14	15	15
Other (3)	2	3	2
Total regulatory liabilities	183	169	62
Associated liabilities			
PRP costs	375	405	432
ERC	62	83	86
Total associated liabilities	437	488	518
Total regulatory and associated liabilities	$620	$657	$580

(1) Presented in other current assets in our condensed consolidated balance sheets.
(2) Presented in other deferred debits and other assets in our condensed consolidated balance sheets.
(3) Presented in other deferred debits and other assets, other current liabilities and accrued postretirement benefit costs in our condensed consolidated balance sheets.
(4) Presented in other current liabilities in our condensed consolidated balance sheets.
(5) Presented in deferred credits in our condensed consolidated balance sheets.

Our regulatory assets and liabilities are described in our Annual Report on Form 10-K for the year ended December 31, 2003. The following represent significant changes to our regulatory assets and liabilities during the six months ended June 30, 2004:

Environmental Response Costs

Our latest engineering estimate for the costs to remediate certain former manufactured gas plant (MGP) sites was $50 million, a reduction of $17 million from the estimate as of December 31, 2003. The decrease was primarily a result of actual expenditures in 2004. For those remaining elements of the MGP program where AGLC is unable to perform engineering cost estimates at the current state of investigation, considerable variability remains in the estimates for future remediation costs. For these elements, the estimate for the remaining cost of future actions at MGP sites is $15 million. AGLC estimates certain other costs related to administering the MGP program and remediation of sites currently in the investigation phase. Through January 2005, AGLC estimates the administrative costs to be $3 million. Beyond January 2005, these costs are not estimable. As of June 30, 2004, our MGP program was approximately 70% complete.

For those sites currently in the investigation phase, our estimate is $9 million. This estimate is based upon preliminary data received during 2003 with respect to the existence of contamination at those sites. Our range of estimates for these sites is from $9 million to $15 million. We have accrued the low end of our range, or $9 million, as this is our best estimate at this phase of the remediation process. AGLC's ERC liability is composed of the elements in the following table:

In millions	June 30, 2004	Dec. 31, 2003	June 30, 2003
Projected engineering estimates and in-place contracts (1)	$50	$67	$85
Estimated future remediation costs (1)	15	15	7
Administrative expenses	3	3	3
Other expenses	9	9	-
Cash payments for cleanup expenditures (2)	(15)	(11)	(9)
Accrued ERC	$62	$83	$86

(1) As of March 31, 2004, September 30, 2003 and March 31, 2003.
(2) Expenditures during the three months ended June 30, 2004, December 31, 2003 and June 30, 2003.

The ERC liability is included in a corresponding regulatory asset. As of June 30, 2004, the regulatory asset was $167 million, which is a combination of accrued ERC and unrecovered cash expenditures. The liability does not include other potential expenses, such as unasserted property damage claims, personal injury or natural resource damage claims, unbudgeted legal expenses, or other costs for which AGLC may be held liable but with respect to which we cannot reasonably estimate an amount.

AGLC has three ways of recovering investigation and cleanup costs. The GPSC has approved an ERC recovery rider. It allows recovery of the costs of investigation, testing, cleanup and litigation. Because of this rider, these actual and projected future costs related to investigation and cleanup to be recovered from customers in future years are included in our regulatory assets. AGLC recovered $12 million during the six months ended June 30, 2004, through its ERC recovery rider.

The second way AGLC can recover costs is by exercising the legal rights AGLC believes it has to recover a share of its costs from other potentially responsible parties, typically former owners or operators of the MGP sites. There was no material recoveries from potentially responsible parties during the six months ended June 30, 2004. The remaining way AGLC can recover costs is from the receipt of net profits from the sale of remediated property. On June 30, 2004, a residential and retail development located in Savannah, Georgia and adjacent to a former MGP site was sold resulting in a gross gain of $6 million. All gains on sales of MGP property are required by the ERC recovery rider to be shared 70% with ratepayers. As a result, approximately $4 million was credited to the MGP program as a reduction to the regulatory asset.

2004 is expected to be the last significant year of spending for this program. The ERC recovery mechanism allows for recovery of expenditures over a five-year period subsequent to the period in which the expenditures are incurred. As of June 30, 2004, the MGP expenditures expected to be incurred over the next 12 months are reflected as a current liability of $37 million. In addition, AGLC expects to collect $26 million in revenues over the next 12 months under the ERC recovery rider, which is reflected as a current asset.

Note 5
Pension and Other Postretirement Benefits

Accounting for Pension Benefits

The measurement date for our pension and other postretirement benefit plans is December 31. The following are the costs components of our pension and other postretirement benefit plans for the second quarter ended June 30, 2004 and 2003.

	Pension Benefits		Other Benefits	
In millions	**2004**	**2003**	**2004**	**2003**
Service cost	$1	$1	$1	$1
Interest cost	5	5	2	2
Expected return on plan assets	(6)	(6)	(1)	(1)
Net amortization	-	-	-	-
Recognized actuarial loss	1	-	-	-
Net annual cost	$1	$-	$2	$2

The following are the cost components for the six months ended June 30, 2004 and 2003.

	Pension Benefits		Other Benefits	
In millions	**2004**	**2003**	**2004**	**2003**
Service cost	$3	$2	$1	$1
Interest cost	10	10	4	4
Expected return on plan assets	(12)	(11)	(2)	(2)
Net amortization	(1)	(1)	-	1
Recognized actuarial loss	2	1	1	-
Net annual cost	$2	$1	$4	$4

Employer Contributions

In April of 2004, we made a $13 million contribution to our pension plan. We do not anticipate making any additional contributions in 2004.

Note 6
Financing

Dollars in millions	Year(s) Due	Int. rate (4)	Outstanding as of: June 30, 2004	Dec. 31, 2003	June 30, 2003
Short-term debt					
Commercial paper (1)	2004	1.4%	$161	$303	$140
Current portion of long-term debt	2004	7.6 – 7.75	34	77	95
Sequent line of credit (2)	2004	-	-	3	7
Total short-term debt (3)		**2.4%**	**$195**	**$383**	**$242**
Long-term debt - net of current portion					
Medium-Term notes					
Series A	2021	9.10%	$30	$30	$30
Series B	2012-2022	8.3 – 8.7	61	61	95
Series C	2015-2027	6.55 – 7.3	117	122	270
Senior Notes	2011-2013	4.45 - 7.125	525	525	300
AGL Capital interest rate swaps	2011-2013	4.57	(5)	(7)	2
Total Medium-Term and Senior notes			$728	$731	$697
Notes payable to Trusts	2037-2041	8.0 – 8.17%	$232	-	-
Trust Preferred Securities					
AGL Capital Trust I	2037	-		$74	$74
AGL Capital Trust II	2041	-		148	147
AGL Capital interest rate swaps	2041	2.58	2	3	7
Total Notes payable to Trusts			234	-	-
Total Trust Preferred Securities				225	228
Total long-term debt (3)		**6.2%**	**$962**	**$956**	**$925**
Total short-term and long-term debt (3)		**5.6%**	**$1,157**	**$1,339**	**$1,167**

(1) The daily weighted average rate was 1.2% for the six months ended June 30, 2004.
(2) The daily weighted average rate was 1.5% for the six months ended June 30, 2004.
(3) Weighted average interest rate, including interest rate swaps if applicable.
(4) Interest rates exclude debt issuance and other financing related costs.

Short-term Debt

Our short-term debt is composed of borrowings under our commercial paper program which consists of short-term unsecured promissory notes with maturities ranging from 14 to 57 days, maturities within one year of our Medium-Term notes, Sequent's line of credit and SouthStar's non-recourse debt. The commercial paper program is supported by our Credit Facility.

On May 26, 2004, we closed on a new $500 million three-year Credit Facility. This new Credit Facility replaces our previous $200 million 364-day Credit Facility that was scheduled to expire on June 16, 2004 and our previous $300 million three-year Credit Facility that was scheduled to terminate on August 7, 2005. Under our new Credit Facility, one time each calendar year we can request from lenders an increase in credit commitments up to an additional $200 million.

On April 19, 2004, SouthStar amended its $75 million revolving line of credit which provides working capital needs to meet seasonal demands. The line of credit is scheduled to expire on April 19, 2007 and is not guaranteed by us. SouthStar's line of credit provides for its working capital needs and meets its seasonal demands. On June 14, 2004, Sequent extended its $25 million line of credit until July 1, 2005, which is used solely for the posting of exchange deposits and is unconditionally guaranteed by us.

Note 7
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 have not been any significant changes to our contractual obligations which were described in our Annual Report on Form 10-K for the year ended December 31, 2003.

Contingent financial commitments represent obligations that become payable only if certain pre-defined 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 tables illustrate our expected financial commitments as of June 30, 2004:

			Commitments Due before December 31,		
In millions	Total	2004	2005 & 2006	2007 & 2008	2009 & Thereafter
Guarantees (1) (2)	$277	$277	$-	$-	$-
Standby letters of credit, performance/ surety bonds	11	9	2	-	-
Total other commercial commitments	$288	$286	$2	$-	$-

(1) $228 million of these guarantees support credit exposures in Sequent's energy marketing and risk management business. In the event that Sequent defaults on any commitments under these guarantees, these amounts would become payable by us as guarantor.

(2) We provide guarantees on behalf of our subsidiary, SouthStar. We guarantee 70% of SouthStar's obligations to Southern Natural Gas Company (SNG) under certain agreements between the parties up to a maximum of $7 million if SouthStar fails to make payment to SNG. Under a second such guarantee, we guarantee 70% of SouthStar's obligations to AGLC under certain agreements between the parties up to a maximum of $42 million, which represents our share of SouthStar's maximum credit support obligation to AGLC under its tariff.

Litigation We are involved in litigation arising in the normal course of business. 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. Change to the status of previously disclosed litigation is as follows:

In the first quarter of 2004, we settled a lawsuit with the city of Augusta, Georgia who had served AGLC with a complaint that was filed in the Superior Court of Richmond County, Georgia on July 1, 2003. The City of Augusta's allegations included fraud and deceit and damages to realty. The allegations arose from negotiations between the city and AGLC regarding the environmental cleanup obligations connected with AGLC's former MGP operations in Augusta.

Note 8
Segment Information

Our business is organized into three operating segments:

- Distribution operations consists of AGLC, Virginia Natural Gas (VNG) and Chattanooga Gas Company (CGC).
- Wholesale services consists primarily of Sequent.
- Energy investments consists primarily of SouthStar, AGL Networks, LLC and US Propane LP through the date of its sale in January 2004.

We treat corporate, our fourth segment, as a non-operating business segment, and it includes AGL Resources Inc., AGL Services Company, Pivotal Energy Development, nonregulated financing and the effect of intercompany eliminations. We eliminated intersegment sales for the three and six months ended June 30, 2004 and 2003 from our statements of consolidated income.

We evaluate segment performance based on the non-GAAP measure of earnings before interest and taxes (EBIT), which includes the effects of corporate expense allocations. Items that we do not include in EBIT are financing costs, including interest and debt expense, income taxes, and the cumulative effect of a change in accounting principle, 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 business 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.

EBIT should not be considered 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, earnings before income taxes and net income for the three and six months ended June 30, 2004 and 2003 are presented below.

	Three months		Six months	
In millions	**2004**	**2003**	**2004**	**2003**
Operating income	$53	$41	$186	$143
Other income	1	8	2	24
Minority interest	(3)	-	(14)	-
EBIT	51	49	174	167
Interest expense	(16)	(18)	(32)	(38)
Earnings before income taxes	35	31	142	129
Income taxes	14	12	55	50
Income before cumulative effect of change in accounting principle	21	19	87	79
Cumulative effect of change in accounting principle	-	-	-	(8)
Net income	$21	$19	$87	$71

As of December 31, 2003	Distribution Operations	Wholesale Services	Energy Investments	Corporate and Intersegment Eliminations (2)	Consolidated AGL Resources
Identifiable assets (1)	$3,325	$454	$90	$2	$3,871
Investment in joint ventures	-	-	101	-	101
Total assets	$3,325	$454	$191	$2	$3,972

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

Three months ended June 30,	Distribution Operations		Wholesale Services		Energy Investments		Corporate and Intersegment Eliminations (2)		Consolidated AGL Resources	
In millions	2004	2003	2004	2003	2004	2003	2004	2003	2004	2003
Operating revenues (1)	$184	$181	$1	$5	$149	$1	($40)	$-	$294	$187
Depreciation and amortization	21	20	-	-	-	-	3	3	24	23
Operating income (loss)	48	44	(5)	-	11	(2)	(1)	(1)	53	41
Equity in earnings of SouthStar	-	-	-	-	-	10	-	-	-	10
Other income (loss)	1	-	-	-	1	(1)	(1)	(1)	1	(2)
Minority interest	-	-	-	-	(3)	-	-	-	(3)	-
EBIT	49	44	(5)	-	9	7	(2)	(2)	51	49
Capital expenditures	49	31	2	1	7	2	-	7	58	41

As of or for the six months ended June 30,	Distribution Operations		Wholesale Services		Energy Investments		Corporate and Intersegment Eliminations (2)		Consolidated AGL Resources	
In millions	2004	2003	2004	2003	2004	2003	2004	2003	2004	2003
Operating revenues (1)	$573	$502	$21	$33	$458	$4	($107)	$-	$945	$539
Depreciation and amortization	42	40	-	-	1	-	5	5	48	45
Operating income (loss)	130	125	7	21	53	(2)	(4)	(1)	186	143
Equity in earnings of SouthStar	-	-	-	-	-	24	-	-	-	24
Other income (loss)	1	-	-	-	2	1	(1)	(1)	2	-
Minority interest	-	-	-	-	(14)	-	-	-	(14)	-
EBIT	131	125	7	21	41	23	(5)	(2)	174	167
Capital expenditures	85	56	5	1	13	6	1	14	104	77
Identifiable assets (3)	$3,297	$3,125	$546	$438	$291	$88	($124)	($110)	$4,010	$3,541
Investment in joint ventures	-	-	-	-	-	112	-	-	-	112
Total assets	$3,297	$3,125	$546	$438	$291	$200	($124)	($110)	$4,010	$3,653

(1) Intersegment revenues – Wholesale services records its energy marketing and risk management revenue on a net basis. The following table provides detail of wholesale services' total gross revenues and gross sales to distribution operations:

	Three months ended June 30,		Six months ended June 30,	
In millions	2004	2003	2004	2003
Third-party gross revenues	$1,013	$808	$2,056	$1,875
Intersegment revenues	101	94	197	207
Total gross revenues	$1,114	$902	$2,253	$2,082

(2) Includes intercompany eliminations; assets consist primarily of cash and cash equivalents and property, plant and equipment.
(3) Identifiable assets are those assets used in each segment's operations.
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Note 9
Subsequent Events

NUI Corporation Acquisition On July 15, 2004, we announced that our board of directors approved a definitive merger agreement under which we will acquire all of the outstanding shares of NUI Corporation (NUI) for $13.70 per share in cash, or $220 million in the aggregate based on approximately 16 million shares outstanding, and the assumption of NUI's outstanding debt at closing. At March 31, 2004, NUI had approximately $607 million in debt and $136 million of cash on its balance sheet, bringing the estimated net value of the acquisition to $691 million.

At closing we expect to fund the purchase of NUI's shares primarily through the issuance of equity or debt securities. We expect to refinance a portion of NUI's outstanding debt and expect to finance at least $220 million of the purchase through the issuance of equity securities. The transaction is subject to approval of NUI's shareholders, the SEC, state regulatory agencies of New Jersey, Florida, Maryland and Virginia and various other closing conditions. We are seeking expedited treatment from the various state and federal regulatory agencies for approval of our proposed merger agreement with NUI. The merger agreement provides that the closing must occur on or prior to April 11, 2005, but the closing may be extended for an additional 90 days until July 11, 2005, in the event the parties have not obtained the required consents for the acquisition.

Postretirement Plan We amended the Defined Benefit Postretirement Health Care and Life Insurance Plan (Defined Plan) due to the Medicare Prescription Drug Improvement and Modernization Act of 2003, which was signed into law December 8, 2003, and which resulted in Medicare offering prescription drug coverage beginning January 1, 2006 to all Medicare-eligible retirees. As a result of this law, effective July 2, 2004 we amended our Defined Plan to discontinue prescription drug benefits to retirees age 65 and older after January 1, 2006.

Treasury Securities From time to time we enter into transactions designed as a hedge against market interest rate fluctuations. On July 2, 2004 we entered into a forward contract transaction involving $100 million of U.S. Treasury securities in order to minimize such fluctuations. The transaction partially hedges an anticipated debt offering in the third or fourth quarter of 2004, and the locked-in Treasury rate was 4.57% with an October 1, 2004 settlement date.

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

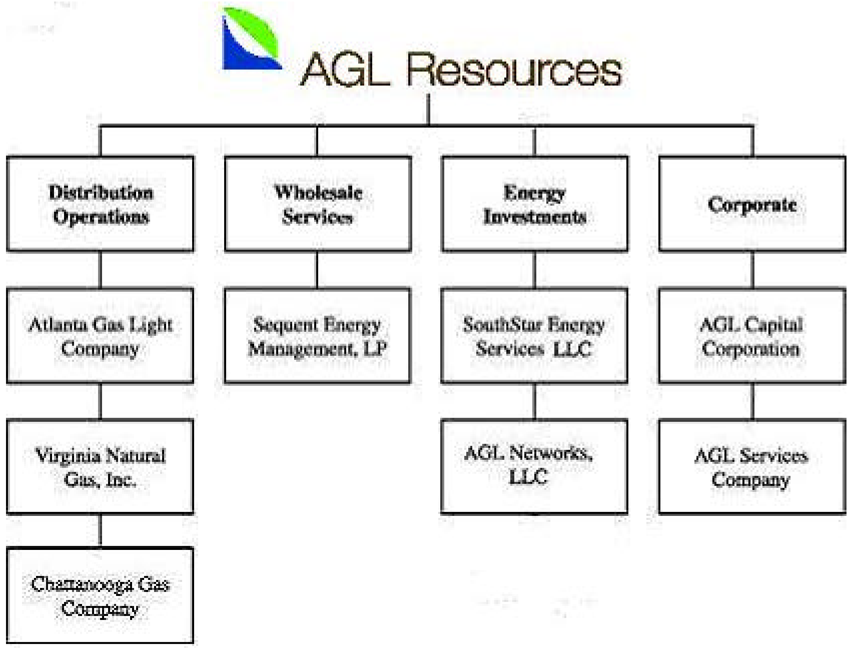
CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

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). Our reports, filings and other public announcements often include statements reflecting assumptions, expectations, projections, intentions or beliefs about future events. These statements, which may relate to such matters as future earnings, growth, supply and demand, costs, subsidiary performance, new technologies and strategic initiatives, are "forward-looking statements" within the meaning of the federal securities laws. These statements do not relate strictly to historical or current facts, and you can identify certain of these statements, but not necessarily all, by the use of the words "anticipate," "assume," "indicate," "estimate," "believe," "predict," "forecast," "rely," "expect," "continue," "grow" and other words of similar meaning. Although we believe that the expectations and assumptions reflected in these statements are reasonable in view of the information currently available, we cannot assure you that these expectations will prove to be correct. These forward-looking statements involve a number of risks and uncertainties, including those set forth below and in our Form 10-K filed with the Securities and Exchange Commission on February 6, 2004 under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Risk Factors." The following are among the important factors that could cause actual results to differ materially from the results discussed in the forward-looking statements:

- changes in industrial, commercial and residential growth in our service territories
- changes in price, supply and demand for natural gas and related products
- impact of changes in state and federal legislation and regulation, including orders of various state public service commissions and of the Federal Energy Regulatory Commission (FERC) on the gas and electric industries and on us
- actions taken by government agencies, including decisions on base rate increase requests by state regulators
- the ultimate impact of the Sarbanes-Oxley Act of 2003 and any future changes in accounting regulations or practices in general with respect to public companies, the energy industry or our operations specifically
- the enactment of new accounting standards by the Financial Accounting Standards Board (FASB) or the Securities and Exchange Commission (SEC) that could impact the way we record revenues, assets and liabilities, which could lead to impacts on reported earnings or increases in liabilities, which in turn could affect our reported results of operations
- effects and uncertainties of deregulation and competition, particularly in markets where prices and providers historically have been regulated and unknown issues following deregulation such as the stability of the Georgia retail gas market, including risks related to energy marketing and risk management
- concentration of credit risk in Marketers – that is, marketers who are certificated by the Georgia Public Service Commission (GPSC) to sell retail natural gas in Georgia – and customers of our wholesale services segment
- excess high-speed network capacity and demand for dark fiber in metro network areas
- market acceptance of new technologies and products, as well as the adoption of new networking standards
- our ability to negotiate new fiber optic contracts with telecommunications providers for the provision of AGL Networks, LLC's dark fiber services
- utility and energy industry consolidation
- performance of equity and bond markets and the impact on pension and post retirement funding costs
- impact of acquisitions and divestitures, including:
  - the risk that our business and NUI Corporation (NUI) will not be integrated successfully or such integration may be more difficult, time-consuming or costly than expected
  - expected revenue synergies and cost savings from the merger may not be fully realized or realized within the expected time frame
  - revenues following the merger may be lower than expected
  - the ability to obtain governmental approvals of the merger on the proposed terms and schedule
  - the failure of NUI's shareholders to approve the merger
  - the risk that we may be unable to obtain financing necessary to consummate the acquisition, or that the terms of such financing may be onerous
  - the risk that any financing plan may have the effect of diluting our shareholder value in the near term
- direct or indirect effects on our business, financial condition or liquidity resulting from a change in our credit rating or the credit rating 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
- impact of changes in weather upon the temperature-sensitive portions of our business
- impact of litigation
- impact of changes in prices on the margins achievable in the unregulated retail gas marketing business

Summary

We are an energy services holding company, headquartered in Atlanta, Georgia, whose principal business is the distribution of natural gas in Georgia, Virginia and Tennessee. Our executive offices are located at Ten Peachtree Place NE, Atlanta, Georgia 30309. The telephone number at that address is (404) 584-4000. As shown in the following chart, we conduct substantially all our operations through our significant subsidiaries, which we manage as three operating segments - distribution operations, wholesale services and energy investments - and one non-operating segment, corporate, which includes our intercompany eliminations.



Distribution operations includes our three regulated utilities that construct, manage and maintain gas pipeline in Georgia, Tennessee and Virginia and serve more than 1.8 million end-use customers. Approximately 83% of our customers are located in Georgia, 14% are located in Virginia and 3% are located in Tennessee. Our wholesale services segment includes our nonutility business engaged in natural gas asset management and optimization, producer services and wholesale marketing, and risk management activities. Our energy investments segment includes our nonutility businesses engaged in retail natural gas marketing and operating telecommunications conduit and fiber infrastructure within select metropolitan areas.

Our overall business strategy is to operate and grow our gas distribution business efficiently and effectively, optimize returns on our assets, and selectively grow our portfolio of closely related businesses while remaining focused on risk management and earnings visibility.

NUI Acquisition On July 15, 2004, we announced that our board of directors approved a definitive merger agreement under which we will acquire all the outstanding shares of NUI for $13.70 per share in cash or approximately $220 million, based on approximately 16 million shares outstanding, and the assumption of NUI's outstanding debt. NUI is a diversified energy company that operates natural gas utilities and natural gas storage and pipeline businesses. NUI provides natural gas to approximately 367,000 residential, commercial and industrial customers in New Jersey, Virginia, Florida and Maryland. This transaction will increase our customer base by 20 percent to approximately 2.2 million.

The total value of the acquisition is $691 million, which includes the assumption of approximately $607 million of NUI's debt and $136 million of cash on its March 31, 2004 balance sheet. We expect to fund the purchase of NUI's shares primarily through the issuance of equity or debt securities, and we also expect to refinance a portion of NUI's outstanding debt upon closing. We ultimately expect to finance at least $220 million of the purchase through the issuance of equity securities. The transaction is subject to approval of NUI's shareholders, the SEC, state regulatory agencies of New Jersey, Florida, Maryland and Virginia and other various closing conditions. We are seeking expedited treatment from the various state and federal regulatory agencies for approval of our proposed merger agreement with NUI. The merger agreement provides that the closing must occur on or prior to April 11, 2005, but the closing may be extended for an additional 90 days until July 11, 2005, in the event the parties have not obtained the required consents for the acquisition.

Natural gas demand, supply and pricing As a result of comparatively milder weather and other industry factors, natural gas prices have declined in the second quarter of 2004. As July and August typically contain the bulk of summer cooling-degree days, industry analysts expect that increased electricity demand will be met by natural gas-fired generation, as high crude oil prices and a tight coal market make those fuels less attractive generation sources. The increased demand will determine the levels of natural gas storage supplies going into the 2004 – 2005 heating season.

In recent weeks, the natural gas market has been driven by storage injections, as local distribution companies, electric utilities, and others who have a requirement to inject gas during the period of April through October have been doing so in substantial quantities. The declining natural gas prices in April, May and June have resulted in these companies injecting 100 percent of all available injection capacity.

Industry dynamics Although natural gas prices have declined in recent months, recent industry information illustrate that domestic production of natural gas has failed to keep pace with demand, creating substantial price volatility in the natural gas markets. The vast majority of North America's gas supply comes from mature producing areas, such as western Canada and the Gulf of Mexico, which have experienced yearly declines in output since 1997. New and supplemental sources of supply will need to be identified in the future to meet the expected increased demand for natural gas and more particularly to dampen volatility and to maintain competitive pric ing. Imported liquefied natural gas (LNG) is the one incremental supply source to the United States, but currently comprises only about 2 percent of the total domestic natural gas supply and cannot grow appreciably without new terminals being sited, licensed and constructed.

We are undertaking a strategy to diversify our natural gas supply portfolio by exploring a variety of options related to LNG supplies and natural gas assets in the southeastern region. Our strategy includes, but is not limited to, taking advantage of existing LNG import terminals or proposed new terminals to route incremental supplies to our storage and distribution facilities. To do so will likely require expansion of some of our natural gas delivery infrastructure to improve both the capacity and reliability of our system. In addition, we are exploring enhanced access to underdeveloped Appalachian natural gas supplies, a strategy which we believe will be enhanced by our proposed acquisition of NUI. We believe that efforts to enhance access to new natural gas supplies will be beneficial in moderating the price of natural gas to our markets over time.

The industry continues to be characterized by significant regional differentials in the delivered price of natural gas. As such, our subsidiary, Sequent Energy Management (Sequent), uses the assets of our utilities and others to take advantage of these differentials, which are highly seasonal and sporadic in nature. In addition, the value of natural gas continues to vary over time and hence our storage capacity can be deployed in part to take advantage of such differences. Through the second quarter of 2004, the curve of forward prices did not exhibit as much differentiation over time as it did last year. As such, the arbitrage value of our storage decreased. As discussed above, the natural gas resource conditions in the market are likely to create price volatility, so we believe the current softness of arbitrage value is unlikely to be a prolonged event. Furthermore, there is a need for some storage for load balancing in the supply area, which is generally unaffected by the forward curve, and hence we expect rapid deliverability storage services, which we offer, to remain in demand.

Competition The principal competition for our distribution operations businesses and SouthStar Energy Services, LLC (SouthStar) are the electric utilities serving the residential and small commercial markets throughout our service areas and the potential displacement or replacement of natural gas appliances with electric appliances. The primary competitive factors are the price of energy and the comfort of natural gas heating compared to electric heating and other energy sources. The increase in wholesale natural gas prices has resulted in increases in the costs of natural gas billed to our customers, and has affected, to some extent, our ability to retain customers, which remains one of our larger challenges in 2004.

Our customers' demand for natural gas and the level of business of our natural gas assets could be affected by numerous factors, including:

- changes in the availability or price of natural gas and other forms of energy
- general economic conditions
- energy conservation
- legislation and regulations
- the capability to convert from natural gas to alternative fuels and
- weather

Sequent competes for asset management business with other energy wholesalers, often through a competitive bidding process. Sequent has historically been successful in obtaining new asset management business by placing bids that were based primarily on the intrinsic value of the transaction, which is the difference in commodity prices between time periods or locations at the inception of the transaction. In recent months, energy wholesalers have become increasingly willing to place bids for asset management transactions that are priced to include extrinsic value which is the additional value for the margins the wholesaler may be able to capture over the term of the asset management deal. We expect this trend to continue in the near term, and the increasing competition for asset management deals could result in downward pressure on the volume of transactions, and the related margins available in this portion of Sequent's business.

Sarbanes-Oxley Act Section 404 We are currently working on our compliance with the Sarbanes-Oxley Act Section 404. This project involves defining and documenting our internal controls processes, evaluating the effectiveness of these controls and establishing the appropriate monitoring and reporting systems. We have started testing our key controls and identifying any potential areas requiring improvement. Our external auditor has started their review of our documentation and controls and we believe that we are on track for certification of our 2004 controls by year-end.

Revenues and Cash flow We generate nearly all of our operating revenues and cash flow through the sale, distribution and storage of natural gas. Distribution operations and energy investments comprise a significant portion of our consolidated revenues for the six months ended June 30, 2004 and 2003.

An estimate of the amount of 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 is also recognized in revenues and recorded as unbilled revenues on our condensed consolidated balance sheet. A significant portion of our operations is subject to variability associated with changes in commodity prices and seasonal fluctuations. During the heating season, which is primarily from November through March, net revenues are higher since generally more customers will be connected in periods of colder weather than in periods of warmer weather.

Our non-utility businesses use physical and financial arrangements to hedge this price risk. Certain hedging and trading activities may require cash deposits to satisfy margin requirements. In addition, reported earnings for the wholesale services and energy investment segments reflect changes in the fair value of certain derivatives; these values may change significantly from period to period.

Operating margin and EBIT We evaluate the performance of our operating segments using the measures of earnings before interest and taxes (EBIT) and operating margin. Our EBIT and operating margin are not measures that are considered to be calculated in accordance with accounting principles generally accepted in the United States of America (GAAP). EBIT is a non-GAAP measure that includes operating income, other income, equity in SouthStar's income in 2003, donations, minority interest in 2004 and gain on sales of assets. Items that are not included in EBIT are financing costs, including interest and debt expense, income taxes and the cumulative effect of changes in accounting principles, each of which are evaluated on a consolidated level.

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 is a non-GAAP measure of income, calculated as revenues minus cost of gas and cost of sales, excluding operation and maintenance expense, depreciation and amortization and taxes other than income taxes. These items are included in our calculation of operating income. We believe operating margin is a better indicator than revenues of the top line contribution resulting from customer growth in our distribution operations segment since the cost of gas is generally passed directly to our customers. We also consider operating margin to be a better indicator in our wholesale services and energy investments segments since it is a direct measure of gross profit before overhead costs.

The following are reconciliations of our operating margin and EBIT to operating income and net income for the three and six months ended June 30, 2004 and 2003 and solely for purposes of comparison reconciliations on a pro-forma basis to adjust the three and six months ended June 30, 2003 as if we had consolidated SouthStar's accounts. This pro-forma presentation is a non-GAAP presentation; however we believe this pro-forma presentation is useful to users of our financial statements since it presents prior year revenues and expenses on the same basis as 2004 following our consolidation of SouthStar pursuant to our adoption of FIN 46R.

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 GAAP. In addition, our operating margin or EBIT may not be comparable to a similarly titled measure of another company.

	Three months ended June 30,				
In millions	**2004** (1)	**2003**	**Pro-forma 2003** (1)	**2004 vs. 2003**	**2004 vs. Pro-forma 2003**
Operating revenues	$294	$187	$282	$107	$12
Cost of gas	129	46	113	83	16
Operating margin	165	141	169	24	(4)
Operating expenses					
Operation and maintenance	81	70	84	11	(3)
Depreciation and amortization	24	23	23	1	1
Taxes other than income taxes	7	7	8	-	(1)
Total operating expenses	112	100	115	12	(3)
Operating income	53	41	54	12	(1)
Other income	1	8	(1)	(7)	2
Minority interest (2)	(3)	--	(4)	(3)	1
EBIT	$51	$49	$49	$2	$2

	Six months ended June 30,				
In millions	**2004** (1)	**2003**	**Pro-forma 2003** (1)	**2004 vs. 2003**	**2004 vs. Pro-forma 2003**
Operating revenues	$945	$539	$877	$406	$68
Cost of gas	522	194	459	328	63
Operating margin	423	345	418	78	5
Operating expenses					
Operation and maintenance	174	142	174	32	-
Depreciation and amortization	48	45	46	3	2
Taxes other than income taxes	15	15	15	-	-
Total operating expenses	237	202	235	35	2
Operating income	186	143	183	43	3
Other income	2	24	-	(22)	2
Minority interest (2)	(14)	--	(16)	(14)	2
EBIT	$174	$167	$167	$7	$7

(1) Includes 100% of SouthStar's revenues and expenses for comparisons among 2003 and 2004 quarters adjusted for SouthStar's consolidation in 2004.
(2) Minority interest adjusts our earnings to reflect our 75% share of SouthStar's earnings in 2004 and our 70% share in 2003 (less Dynegy Inc.'s 20% share of SouthStar's income prior to February 18, 2003).

Second quarter 2004 earnings Our second quarter results reflect an increase in distribution operation's EBIT as compared to last year. This reflects higher pipeline replacement revenues, increased customer growth and higher carrying charges for Marketer's stored gas. This was offset partially by Sequent's decreased operating margin. The decrease in operating margin was due to lower volatility in the natural gas market primarily associated with narrowing storage spreads, resulting in fewer positive price differences in storage opportunities.

Six month 2004 earnings The increase in earnings for the six months ended June 30, 2004 was due in large part to SouthStar's strong performance. Despite higher energy prices, lower volatility in the second quarter of 2004 affected Sequent's performance. Compared to the prior year, Sequent's operating margins were lower as we experienced reduced volatility and price movements across geography and spreads in the forward curve over time, despite 17 percent higher trading volumes.

	Three months ended June 30,			**Six months ended June 30,**		
In millions, except per share amounts	**2004**	**2003**	**2004 vs. 2003**	**2004**	**2003**	**2004 vs. 2003**
EBIT by segment						
Distribution operations	$49	$44	$5	$131	$125	$6
Wholesale services	(5)	-	(5)	7	21	(14)
Energy investments	9	7	2	41	23	18
Corporate	(2)	(2)	-	(5)	(2)	(3)
Consolidated EBIT	51	49	2	174	167	7
Interest expense	16	18	(2)	32	38	(6)
Earnings before income taxes	35	31	4	142	129	13
Income taxes	14	12	2	55	50	5
Income before cumulative effect of change in accounting principle	21	19	2	87	79	8
Cumulative effect of change in accounting principle	-	-	-	-	(8)	8
Net income	$21	$19	$2	$87	$71	$16
Basic earnings per common share						
Income before cumulative effect of change in accounting principle	$0.34	$0.30	$0.04	$1.35	$1.27	$0.08
Cumulative effect of change in accounting principle	-	-	-	-	(0.13)	0.13
Basic earnings per common share	$0.34	$0.30	$0.04	$1.35	$1.14	$0.21
Diluted earnings per common share						
Income before cumulative effect of change in accounting principle	$0.33	$0.29	$0.04	$1.33	$1.26	$0.07
Cumulative effect of change in accounting principle	-	-	-	-	(0.13)	0.13
Diluted earnings per common share	$0.33	$0.29	$0.04	$1.33	$1.13	$0.20
Weighted average number of common shares outstanding						
Basic	64.8	63.5	1.3	64.7	61.9	2.8
Diluted	65.6	64.2	1.4	65.5	62.4	3.1

Interest expense The decrease in interest expense for the three and six months ended June 30, 2004 as compared to the same periods in 2003 was a result of lower interest rates on commercial paper borrowings, lower average debt balances, the repayment of Medium-Term notes in 2003 and interest rate swap transactions. As shown in the following table, our average debt balances were lower as compared to last year, due to the proceeds generated from the equity offering, which occurred on February 14, 2003, approximately $76 million of cash distributions from SouthStar from December 2003 through June 2004 and lower working capital needs.

	Three months ended June 30,			Six months ended June 30,		
Dollars in millions	**2004**	**2003**	**2004 vs. 2003**	**2004**	**2003**	**2004 vs. 2003**
Total interest expense	$16	$18	($2)	$32	$38	($6)
Average debt outstanding (1)	1,078	1,114	(36)	1,146	1,205	(59)
Average rate	5.9%	6.5%	(0.6%)	5.6%	6.3%	(0.7%)

(1) Daily average of all outstanding debt including our note payable to Trusts in 2004 and Trust Preferred Securities in 2003.

As of June 30, 2004, $34 million of long-term fixed-rate obligations are scheduled to mature within the next 12 months. Any new debt obtained to refinance this obligation will be exposed to changes in interest rates. For the six months ended June 30, 2004, had market interest rates been 100 basis points higher, representing a 3.6% interest rate on our variable rate debt versus our actual 2.6% interest rate we incurred, our year-to-date pretax interest expense would have increased by $3 million.

Income tax expense The increase in income tax expense of $2 million and $5 million for the three and six months ended June 30, 2004 was primarily due to the increase in earnings before income taxes, offset by a decrease in the effective tax rate. The decrease in the effective tax rate was primarily due to a decrease in state taxes, which was partially offset by additional tax expense due to recognition of a tax gain from our sale of our general and limited partnership interest in US Propane.

	Three months ended June 30,			Six months ended June 30,		
Dollars in millions	**2004**	**2003**	**2004 vs. 2003**	**2004**	**2003**	**2004 vs. 2003**
Earnings before income taxes	$35	$31	$4	$142	$129	$13
Income tax expense	14	12	2	55	50	5
Effective tax rate	38.5%	39.0%	(0.5%)	38.5%	39.0%	(0.5%)

Results of Operations

Distribution Operations

Distribution operations include the results of operations and financial condition of our three natural gas local distribution utility companies: Atlanta Gas Light Company (AGLC), Virginia Natural Gas (VNG) and Chattanooga Gas Company (CGC). Each utility operates subject to regulations provided by the state regulatory agencies in its service territories. The Georgia Public Service Commission (GPSC) regulates AGLC; the Virginia State Corporation Commission (VSCC) regulates VNG; and the Tennessee Regulatory Authority (TRA) regulates CGC 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 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 deferred income tax liabilities and certain other deductions. We continuously monitor the performance of our utilities to determine whether rates need to be adjusted by making a rate case filing.

- **AGLC** is a natural gas local distribution utility with distribution systems and related facilities throughout Georgia. AGLC has approximately six Bcf of LNG storage capacity in three LNG plants to supplement the supply of natural gas during peak usage periods. Pursuant to the Georgia Natural Gas Competition and Deregulation Act, AGLC is designated as an "electing distribution company," which means that AGLC is required to offer LNG peaking services to Marketers—that is, marketers who are certificated by the GPSC to sell retail natural gas in Georgia--at rates and on terms approved by the GPSC. On October 1, 2004 we will file with the GPSC the information necessary to determine if AGLC's current performance based rates will be extended, modified, or terminated subsequent to April 30, 2005.

  AGLC has executed an agreement with Southern Natural Gas (SNG), a subsidiary of El Paso Corporation, to acquire a portion of SNG's interstate pipeline that runs from Macon, Georgia to Atlanta, Georgia. The transaction is valued at approximately $32 million. As part of the agreement, AGLC will extend the existing SNG transportation and storage contracts to ensure reliable delivery of natural gas into Georgia in return for the right to expand AGLC's system off of the purchased facilities. We expect the SNG transaction to close by April 30, 2005, subject to securing regulatory approvals.

  In May 2004, AGLC and 8 of the 10 Marketers entered into a settlement which resolved matters related to the capacity supply plan that was required to be filed by AGLC on July 1, 2004. As a result of the settlement, the parties filed with the GPSC a three year capacity supply plan for the Georgia market. A hearing is scheduled in early September 2004, with the final GPSC decision and order expected on September 29, 2004. The plan includes, among other things:
  - calculation of the design (peak) day requirements for the next three years;
  - purchase by AGLC of certain SNG facilities and the recovery of those costs through the Pipeline Replacement Program;
  - construction of a line from the Macon LNG facility to those SNG facilities;
  - extension of the Sequent peaking contract; and
  - other tariff provisions.

- **VNG** is a natural gas local distribution utility with distribution systems and related facilities serving southeastern Virginia. VNG owns and operates approximately 155 miles of a separate high-pressure pipeline that provides delivery of gas to customers under firm transportation agreements within the state of Virginia. VNG also has approximately five million gallons of propane storage capacity in its two propane facilities to supplement the supply of natural gas during peak usage periods.

  In 2004, Pivotal Propane of Virginia, Inc., (Pivotal Propane) our wholly owned subsidiary intends to complete the construction of a propane air facility in the VNG service area to provide VNG with 28,800 dekatherms of propane air per day on a 10-day-per-year basis to serve its peaking needs. VNG has received approval from the VSCC for the $27 million propane air plant to improve the reliability of its system in Virginia. The propane-air facility is currently under construction, and we expect to have the facility completed in time for the beginning of the winter heating season.

  In June 2004, the VSCC issued its final order authorizing the recovery of all charges for this service through VNG's gas cost recovery mechanism. The approval is for an initial 10-year term, with the possibility of renewal thereafter for terms of two years subject to VSCC approval. VNG has the right to purchase the facility at the end of the initial term or any renewal term. We expect the facility to become operational by the end of 2004.

  In June 2004, VNG filed for a 3-year extension of its weather normalization adjustment program. This filing included a fully adjusted cost of service study along with the same schedules required for a general rate case.

- **CGC** is a natural gas local distribution utility with distribution systems and related facilities serving the Chattanooga and Cleveland areas of Tennessee. CGC has approximately 1.2 Bcf of LNG storage capacity in its LNG plant. Included in the rates charged by CGC is a WNA factor, which offsets the impact of unusually cold or warm weather on operating margin.

  In January 2004, CGC filed a rate plan request with the TRA for a total rate increase of $4.5 million annually. The rate plan was filed to cover CGC's rising cost of providing natural gas to its customers. In May 2004 the TRA suspended the increase until July 28, 2004. Since its initial filing, CGC reduced its rate plan increase to $3.9 million, as a result of the February 2004 TRA ruling discussed below. On September 1, 2004, new rates will become effective, subject to a final authority by the TRA, which we expect by December 2004.

  In March 2003, CGC filed a joint petition with other Tennessee distribution companies requesting the TRA issue a declaratory ruling that the portion of uncollectible accounts directly related to the cost of its natural gas is recoverable through a Purchased Gas Adjustment (PGA) mechanism. The PGA mechanism allows the local distribution companies to automatically adjust their rates to reflect changes in the wholesale cost of natural gas and to insure the utilities recover 100% of the cost incurred in purchasing gas for their customers. On February 9, 2004 the TRA ruled that the gas portion of accounts written-off as uncollectible after March 10, 2004 could be recovered through the PGA.

Results of Operations for the three and six months ended June 30, 2004 and 2003 are as follows:

In millions	Three months ended June 30, 2004	2003	2004 vs. 2003	Six months ended June 30, 2004	2003	2004 vs. 2003
Operating revenues	$184	$181	$3	$573	$502	$71
Cost of gas	44	45	(1)	253	193	60
Operating margin	140	136	4	320	309	11
Operating expenses						
Operation and maintenance	66	66	-	136	131	5
Depreciation and amortization	21	20	1	42	40	2
Taxes other than income	5	6	(1)	12	13	(1)
Total operating expenses	92	92	-	190	184	6
Operating income	48	44	4	130	125	5
Other income	1	-	1	1	-	1
EBIT	$49	$44	$5	$131	$125	$6
Metrics						
Average end-use customers (in thousands)	1,862	1,852	1%	1,868	1,857	1%
Operation and maintenance expenses per customer	$35	$36	(3%)	$73	$71	3%
EBIT per customer	$26	$24	8%	$70	$67	4%
Customers per employee	1,046	983	6%	1,039	981	6%
Throughput (in millions of dekatherms)						
Firm	23	23	-%	113	113	-%
Interruptible	24	27	(11%)	52	54	(4%)
Total	47	50	(6%)	165	167	(1%)
Heating degree days (1):			% Colder / (Warmer)			% Colder / (Warmer)
Georgia	157	132	19%	1,660	1,685	(1%)
Virginia	223	307	(27%)	2,076	2,269	(9%)
Tennessee	214	117	83%	1,930	1,942	(1%)

(1) We measure the effects of weather on our businesses using "degree days." The measure of degree days for a given day is the difference between the average daily actual temperature and the baseline temperature of 65 degrees Fahrenheit. Heating degree days result when the average daily actual temperature is less than the 65-degree baseline. Generally, increased heating degree days result in greater demand for gas on our distribution systems.

2nd Quarter 2004 compared to 2nd Quarter 2003 The increase in EBIT of $5 million was primarily the result of increased operating margin at AGLC of $4 million, which was due mainly to the following:

- $2 million increase due to customer growth
- $1 million increase in pipeline replacement program (PRP) revenue due to continued PRP capital spending; and
- $1 million in additional carrying charges for marketers' gas storage due to higher storage volumes combined with higher weighted average cost of gas.

6 months 2004 compared to 6 months 2003 The increase in EBIT of $6 million was primarily the result of increased operating margin of $11 million, partially offset by increased operating expenses. The increase in operating margin was due primarily to the following:

- AGLC's operating margin increased $8 million resulting from an increase of $2 million in pipeline replacement program (PRP) revenue due to continued PRP capital spending; $2 million in additional carrying charges for gas stored for marketers due to higher storage volumes combined with higher weighted average cost of gas, $1 million in other revenue, primarily from contracts to provide maintenance services to non-traditional customers, and; $3 million increase due to increased customer growth.
- VNG's and CGC's operating margin increased $3 million due primarily to increased customer growth.

Operating expenses for the six months was $190 million, up from $184 million in the same period last year. The increase of $6 million was primarily a result of:

- $5 million increase in operations and maintenance expense as a result of increases in information services and technology costs due to software maintenance; costs for locating gas infrastructure due to increased customer requests; and marketing expenses for a gas appliance program
- $1 million additional pension expense
- $2 million increase in depreciation expense primarily from new depreciation rates at VNG and increased assets at each utility
- Partly offset by a $2 million reduction in expenses from reduced AGLC property taxes and reductions in bad debt primarily due to a TRA ruling that allows for recovery of the gas portion of accounts written off as uncollectible at CGC and increased collection efforts at VNG

Wholesale Services

Wholesale services includes the results of operations and financial condition of Sequent, our subsidiary involved in asset optimization, producer services, wholesale marketing and risk management. Our asset optimization business focuses on capturing 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. 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 the other alternatives available to its end-use customers.

Regulatory Agreements We have reached the following agreements with state regulatory commissions related to Sequent's role as asset manager for our regulated utilities. Failure to renew these agreements would have a significant impact on Sequent's EBIT.

- Various Georgia statutes require Sequent, as asset manager for AGLC, to share 90% of its earnings from capacity release transactions with Georgia's Universal Service Fund (USF). A December 2002 GPSC order requires net margin earned by Sequent, for transactions involving AGLC assets other than capacity release, to be shared equally with the USF. For the six months ended June 30, 2004, we contributed $1.3 million to the USF based upon profits earned in 2003.
- In November 2000, the VSCC approved an asset management agreement that provides for a sharing of profits between Sequent and VNG's customers. This agreement expires in October 2005, unless Sequent, VNG and the VSCC agree to extend the contract. In December 2003, we contributed $4.7 million to VNG's customers for the contract year November 2002 through October 2003. This contribution will be reflected as a reduction to customer gas cost in 2004. We will contribute profits earned in the contract year November 2003 through October 2004 in December 2004.
- In June 2003, CGC's tariff was amended effective January 1, 2003 to require net margin earned by Sequent for transactions involving CGC assets to be shared equally with CGC ratepayers. This agreement expires in April 2006 and is subject to automatic extensions unless specifically terminated by either party. In 2004, Sequent contributed $1.3 million to CGC based upon profits earned during 2003. This contribution is being reflected as a reduction to customer gas cost in 2004.

Peaking Services Wholesale services generates operating margin through, among other things, the sale of peaking services, which includes receiving a fee from customers that guarantees that they will receive gas under peak conditions. Sequent recorded gross revenues of $7 million in the six months ended June 30, 2004 under these peaking services and $6 million during the same period in 2003. Wholesale services incurs costs to support its obligations under these agreements, which will be reduced in whole or in part as the matching obligations expire. Wholesale services' affiliated peaking arrangement expired March 31, 2004. In July 2004, AGLC submitted a capacity supply plan to the GPSC that includes a request for the extension of the Sequent peaking services agreement.

In addition, we renewed and extended for 5 years a separate non-affiliated peaking service agreement that begins in November 2004 and ends in March 2009. If these arrangements, including those with AGLC, are renewed, it is likely that future fees may not be reset at current levels. We will continue to seek new peaking transactions as well as work toward extending those that are set, or have expired.

Energy Marketing and Risk Management Activities For the six months ended June 30 in each year, Sequent recorded unrealized gains of $15 million in 2004 and $6 million in 2003, excluding the cumulative effect of a change in accounting principle, related to changes in the fair value of derivative instruments utilized in our energy marketing and risk management activities. The tables below illustrate the change in the net fair value of the derivative instruments and energy-trading contracts during the three and six months ended June 30, 2004 and 2003 and provide details of the net fair value of contracts outstanding as of June 30, 2004. Sequent's storage positions are affected by price sensitivity in the New York Mercantile Exchange, Inc. (NYMEX) average price.

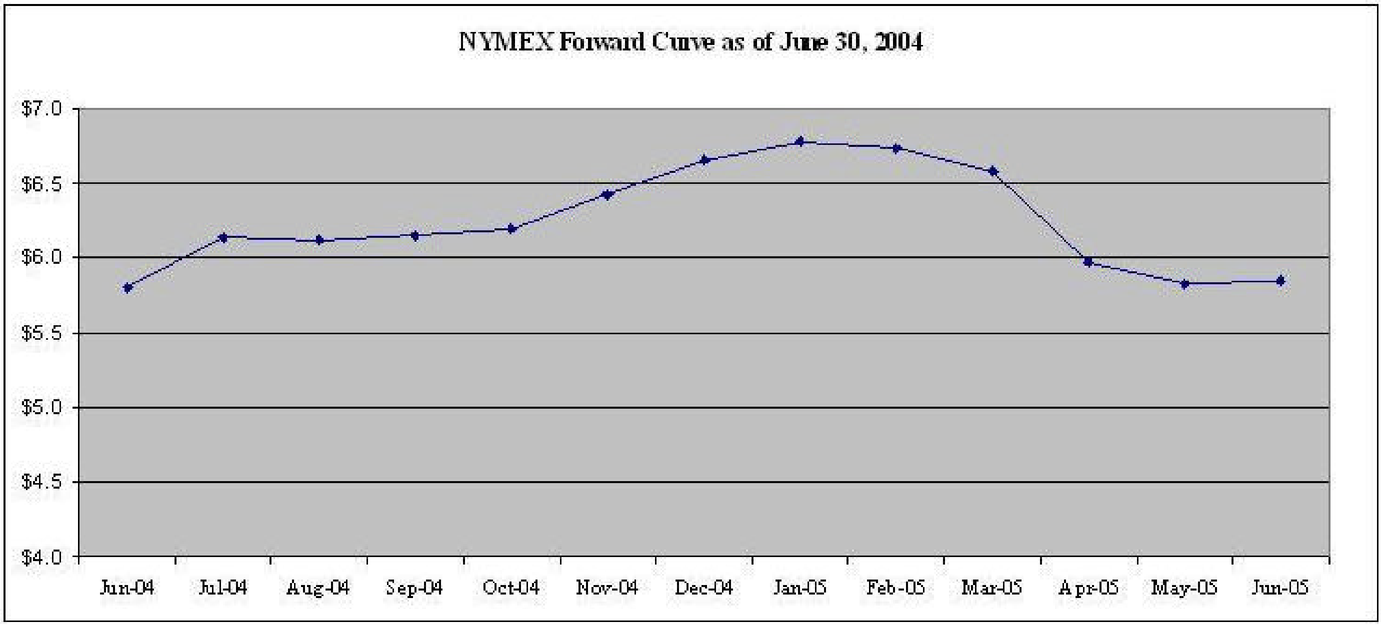
	Three months ended June 30,		Six months ended June 30,	
In millions	2004	2003	2004	2003
Net fair value of contracts outstanding at beginning of period	$10	$4	($5)	$7
Cumulative effect of change in accounting principle	-	-	-	(13)
Net fair value of contracts outstanding at beginning of period, as adjusted	10	4	(5)	(6)
Contracts realized or otherwise settled during period	3	(1)	7	(4)
Change in net fair value of contracts	(3)	(3)	8	10
Net fair value of contracts outstanding at end of period	$10	$-	$10	$-

The sources of our net fair value at June 30, 2004 are as follows:

In millions	Matures through June 2005	Matures through June 2008	Matures through June 2010	Matures after June 2010	Total Net Fair Value
Prices actively quoted (1)	$7	$2	$-	$-	$9
Prices provided by other external sources (1)	-	1	-	-	1

(1) 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 basis 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.

Storage Inventory Outlook The NYMEX forward curve graph set forth below reflects the NYMEX natural gas prices as of June 30, 2004 through June 2005, and reflects the prices we could buy natural gas at the Henry Hub for delivery in the same time period. July 2004 futures expired on June 28, 2004, however they are included as they coincide with the July storage withdrawals. 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.



As shown in the following table, "Open futures NYMEX contracts" represents the volume in contract equivalents of the transactions we executed to hedge our storage inventory. As of June 30, 2004, the expected withdrawal schedule of this inventory and its weighted average costs are reflected in the category "physical withdrawal schedule as of June 30, 2004 (NYMEX contract equivalents.)" Our futures contracts qualify as derivatives under Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133) and are accounted for at fair value (mark-to-market). However, the storage inventory is accounted for under the accrual method, at the lower of average cost or market, resulting in a timing mismatch in earnings recognition.

We recognize the gains or losses on the futures contracts in the period the price changes; we recognize the gains or losses on the storage inventory as the gas is withdrawn from storage. The schedule also reflects that our storage inventory is fully hedged with futures, which results in an overall locked-in margin, timing notwithstanding. "Expected gross margin after regulatory sharing" reflects the gross margin we would generate in future periods based on the forward curve and inventory withdrawal schedule at June 30, 2004. This gross margin could change in the future as we adjust our daily injection and withdrawal plans due to changes in market conditions.

	July 2004	Aug 2004	Sept. 2004	Oct. 2004	Nov. 2004	Dec. 2004	Jan. 2005	Feb. 2005	Mar. 2005
Open futures NYMEX contracts - (short) long (1)	(197)	(583)	(56)	6	4	-	-	(60)	(25)
Physical withdrawal schedule as of June 30, 2004 (NYMEX contract equivalents)									
Salt dome (WACOG (2) = $5.96)	78	11	-	-	-	-	-	-	-
Reservoir (WACOG (2) = $4.52)	119	572	56	(6)	(4)	-	-	60	25
Total	197	583	56	(6)	(4)	-	-	60	25
Expected gross margin, after regulatory sharing (3) *(In millions)*									
Reservoir	$0.2	$-	$-	$-	$-	$-	$-	$-	$-
Salt dome	0.2	0.4	0.2	-	-	-	-	0.4	$0.4

(1) July futures expired on June 28, 2004; however, they are included herein as they coincide with the July storage withdrawals.

(2) WACOG = Weighted average cost of gas

(3) At June 30, 2004, as a result of our positions, a $0.10 parallel change in future NYMEX prices would impact our EBIT by $0.6 million. As shown, our net position is flat, and price movements should only affect timing of earnings between periods as futures contracts are marked to market but inventory is recorded at the lower of average cost or market.

Park and Loan Outlook Additionally, we have entered into park and loan transactions with various pipelines. A park and loan transaction is a tariff transaction offered by pipelines, where the pipeline allows the customer to park natural gas on or borrow natural gas from the pipeline in one period and reclaim natural gas from or repay natural gas to the pipeline in a subsequent period. The economics of these transactions are evaluated and managed similar to the way traditional reservoir and salt dome storage transactions are evaluated. However, these transactions have elements that qualify as derivatives in accordance with SFAS 133.

Under SFAS 133, the transactions are considered financing arrangements when the contracts contain fixed volumes that are payable or repaid at determinable dates and at a specific point in time to third parties. Because these park and loan transactions have fixed volumes, they contain price risk for the change in market prices from the date the transaction is initiated to the time the natural gas is repaid. As a result, these transactions qualify as derivatives under SFAS 133 and must be recorded at their fair value. Certain park and loan transactions that we execute meet this definition.

As such, we account for these transactions at fair value once the transaction has started (either the natural gas is originally parked on or borrowed from the pipeline). "Park and (loan) volumes" represents the contract equivalent for the volumes of our park and loan transactions as of June 30, 2004 that is not already accounted for at fair value. "Expected gross margin from park and loans" represents the gross margin from those transactions expected to be recognized in future periods based on the NYMEX forward curves at June 30, 2004.

	July 2004	Aug. 2004	Sept. 2004	Oct. 2004	Nov. 2004	May 2005	June 2005	July 2005	Total
Park and (loan) volumes	(100)	(62)	(31)	(41)	(80)	61	91	162	-
Expected gross margin from park and loans *(in millions)*	($0.3)	($0.4)	($0.2)	($0.2)	($0.1)	$-	$-	$-	($1.1)

Results of Operations for the three and six months ended June 30, 2004 and 2003 are as follows:

In millions	Three months ended June 30, 2004	2003	2004 vs. 2003	Six months ended June 30, 2004	2003	2004 vs. 2003
Operating revenues	$1	$5	($4)	$21	$33	($12)
Cost of sales	1	-	1	1	-	1
Operating margin	-	5	(5)	20	33	(13)
Operating expenses						
Operation and maintenance	5	5	-	13	12	1
Depreciation and amortization	-	-	-	-	-	-
Taxes other than income	-	-	-	-	-	-
Total operating expenses	5	5	-	13	12	1
Operating income	(5)	-	(5)	7	21	(14)
Other income	-	-	-	-	-	-
EBIT	($5)	$-	($5)	$7	$21	($14)
Metrics						
Physical sales volumes (Bcf/day)	2.00	1.71	17%	2.05	1.83	12%

2nd Quarter 2004 compared to 2nd Quarter 2003 The $5 million decline in EBIT was the result of decreased operating margin. The decrease was due to lower volatility in the natural gas market primarily associated with narrowing storage spreads. The net result is that we had fewer storage arbitrage opportunities in 2004 compared to 2003. Despite reduced volatility during 2004, Sequent's sales volumes increased 17% from 1.71 billion cubic feet (Bcf) per day in 2003 to 2.00 Bcf per day in 2004. We experienced increased volumes predominantly due to customer growth in the producer services and end-user areas of our business.

During the second quarter 2004, Sequent recognized an expense of $0.7 million associated with the reduction of a portion of our natural gas inventory to market prices that were below the average carrying cost of the inventory. Our adjusted weighted average cost of gas stored in inventory was $5.90 per millions of British thermal units (MMBtu) at the end of the second quarter of 2004, compared to $5.56 per MMBtu during the same period in 2003.

6 months 2004 compared to 6 months 2003 The decrease in EBIT of $14 million was the result of decreased operating margin and increased operating expenses. The decrease in operating margin was due primarily to lower volatility in natural gas in 2004. The dampening effect of region-to-region volatility compressed Sequent's trading and marketing activities and the expected margins within its transportation portfolio.

During the first quarter of 2004, the weighted average cost of natural gas stored in inventory that was sold was $5.06 per MMBtu. This was substantially higher than the $2.20 per MMBtu during the same period last year, thus yielding reduced margins during early 2004 compared to 2003. Sequent's operating expenses increased modestly compared to 2003 due to additional payroll expenses associated with an increase in the number of employees, and additional costs for outside services attributable to consultants and contractors due in part to our Sarbanes-Oxley Act compliance activities.

Energy Investments

Our energy investments segment includes the consolidated results of operations and financial condition of SouthStar in 2004, our equity investment in SouthStar in 2003, the results of operations and financial condition of AGL Networks, LLC (AGL Networks), and our equity investment in US Propane LP (US Propane), through the date of its sale in January 2004.

On January 20, 2004, we executed an agreement to sell our general and limited partnership interests in US Propane. The aggregate transaction was valued at $130 million. Upon closing, we received $29 million for the sale of our interests. We recognized a gain of $1.1 million on this transaction in 2004, which we recorded in other income.

- **SouthStar** is a joint venture formed in 1998 by our subsidiary, Georgia Natural Gas Company, Piedmont and Dynegy Inc. (Dynegy) to market natural gas and related services to retail customers, principally in Georgia. On March 11, 2003, we purchased Dynegy's 20% ownership interest in a transaction that for accounting purposes had an effective date of February 18, 2003.

  We currently own a non-controlling 70% financial interest in SouthStar and Piedmont owns the remaining 30%. Our 70% interest is non-controlling because all significant management decisions require approval by both owners. On March 29, 2004, we executed an amended and restated partnership agreement with Piedmont. This amended and restated partnership agreement calls for SouthStar's future earnings starting in 2004 to be allocated 75% to our subsidiary and 25% to Piedmont. In addition, we executed a services agreement, which provided that AGL Services Company will provide and administer accounting, treasury, internal audit, human resources and information technology functions.

- **AGL Networks**, our wholly owned subsidiary, is a provider of telecommunications conduit and un-used fiber optic cable or dark fiber. AGL Networks leases and sells its fiber to a variety of customers in the Atlanta, Georgia and Phoenix, Arizona metropolitan areas, with a small presence in other cities in the United States. Its customers include local, regional and national telecommunications companies, internet service providers, educational institutions and other commercial entities.

  AGL Networks typically provides underground conduit and dark fiber to its customers under leasing arrangements with terms that vary from 1 to 20 years. In addition, AGL Networks offers telecommunications construction services to companies. Our primary goals for this business in the next 12 to 15 months are to:

  - increase revenues through our sales efforts,
  - maintain control of capital costs for connecting customers to the network,
  - and maintain control of sales and operating expenses.

Results of operations for energy investments for the three and six months ended June 30, 2004 and 2003 are shown in the following tables. We have also included pro-forma results as if SouthStar's accounts were consolidated with our subsidiaries' accounts for the three and six months ended June 30, 2003. These unaudited pro-forma results are presented for comparative purposes only.

	Three months ended June 30,				
In millions	**2004** (1)	**2003**	**Pro-forma 2003** (1)	**2004 vs. 2003**	**2004 vs. Pro-forma 2003**
Operating revenues	$149	$1	$137	$148	$12
Cost of sales	124	1	110	123	14
Operating margin	25	-	27	25	(2)
Operating expenses					
Operation and maintenance	13	2	16	11	(3)
Depreciation and amortization	-	-	-	-	-
Taxes other than income	1	-	-	1	1
Total operating expenses	14	2	16	12	(2)
Operating income (loss)	11	(2)	11	13	-
Equity earnings from SouthStar	-	10	-	(10)	-
Other income	1	(1)	-	2	1
Total other income	1	9	-	(8)	1
Minority interest (2)	(3)	-	(4)	(3)	1
EBIT	$9	$7	$7	$2	$2

(1) Includes 100% of SouthStar's revenues and expenses for comparisons among 2003 and 2004 quarters adjusted for SouthStar's consolidation in 2004.
(2) Minority interest adjusts our earnings to reflect our 75% share of SouthStar's earnings in 2004 and our 70% share in 2003 (less Dynegy Inc.'s 20% share of SouthStar's income prior to February 18, 2003).

2nd Quarter 2004 compared to 2nd Quarter 2003 The increase in EBIT of $2 million for the second quarter 2004 compared to the same period in 2003 is primarily due to the gain on the sale of a residential and retail development which is located in Savannah, Georgia, adjacent to a former manufactured gas plant site owned by AGLC, offset by lower results at SouthStar. On a pro-forma basis, operating margin decreased by $2 million as a result of unusually strong margins and higher usage due to colder weather during April 2003 that was not achieved at the same level in the second quarter 2004. In addition, in 2003 SouthStar recognized $1 million on the sale of gas inventory which was reassigned to AGLC.

Operating expenses decreased by $2 million as a result of the sale of the residential and retail development and lower bad debt expenses at SouthStar due to ongoing active customer collection process improvements and increased quality customer base. The increase in other income of $1 million is due to higher income from US Propane of $2 million, resulting from a $1 million gain on the sale of our remaining investment units in 2004 as compared to prior year operating losses at US Propane.

In millions	Six months ended June 30, 2004 (1)	2003	Pro-forma 2003 (1)	2004 vs. 2003	2004 vs. Pro-forma 2003
Operating revenues	$458	$4	$432	$454	$26
Cost of sales	375	1	356	374	19
Operating margin	83	3	76	80	7
Operating expenses					
Operation and maintenance	28	5	37	23	(9)
Depreciation and amortization	1	-	1	1	-
Taxes other than income	1	-	-	1	1
Total operating expenses	30	5	38	25	(8)
Operating income (loss)	53	(2)	38	55	15
Equity earnings from SouthStar	-	24	-	(24)	-
Other income	2	1	1	1	1
Total other income	2	25	1	(23)	1
Minority interest (2)	(14)	-	(16)	(14)	2
EBIT	$41	$23	$23	$18	$18
Metrics					
SouthStar					
Average customers (in thousands) (3)	542	562	-	(4%)	-
Market share in Georgia (3)	36%	38%	-	(5%)	-

(1) Includes 100% of SouthStar's revenues and expenses for comparisons among 2003 and 2004 quarters adjusted for SouthStar's consolidation in 2004.
(2) Minority interest adjusts our earnings to reflect our 75% share of SouthStar's earnings in 2004 and our 70% share in 2003 (less Dynegy Inc.'s 20% share of SouthStar's income prior to February 18, 2003).
(3) 12 month average ending June 30.

6 months 2004 compared to 6 months 2003 The increase in EBIT for the six months ended 2004 as compared to the same period in 2003 is primarily due to strong results from SouthStar. The improved results at SouthStar primarily reflect higher operating margins and substantially lower bad debt expense, as well as our expanded ownership in the joint venture. Our ownership percentage increased from 50% to 70% on February 18, 2003 and the amended operating agreement of SouthStar provides for us to receive 75% of its earnings beginning in 2004.The decrease in SouthStar's market share of 4% is primarily as a result of the improved credit worthiness of its customer base.

On a pro-forma basis, the increase in EBIT was due primarily to increased operating margin of $7 million. This was due to:

- higher margin per unit and lower hedging cost in 2004 as compared to 2003 which resulted in a increase in margin of $10 million, offset by
- sale of gas inventory reassigned to AGLC of $1 million in 2003
- one-time asset sale of $2 million by AGL Networks in 2003.

Operating expenses decreased by $8 million due to the following:

- lower bad debt expense of $5 million as a result of ongoing active customer collection process improvements and increased quality customer base,
- lower customer care expenses of $2 million due to receipt of vendor credits,
- sale of a residential and retail development property located in Savannah, Georgia of $2 million,

The increase in other income of $1 million is due to additional contributions from US Propane of $2 million, resulting from a $1 million gain on the sale of our remaining investment units in 2004 compared to prior year operating losses at US Propane.

Consolidation of SouthStar Pursuant to our adoption of FIN 46R, we consolidated all of SouthStar's accounts with our subsidiaries' accounts as of March 31, 2004. We recorded Piedmont's portion of SouthStar's earnings as a minority interest in our condensed consolidated statements of income and Piedmont's portion of SouthStar's contributed capital as a minority interest on our condensed consolidated balance sheet. We eliminated any intercompany profits between segments. Below are our unaudited pro-forma condensed consolidated balance sheet and statement of income, presented as if SouthStar's balances were consolidated with our subsidiaries' accounts as of December 31, 2003. This pro-forma presentation is a non-GAAP presentation; however we believe this pro-forma presentation is useful to users of our financial statements since it presents prior year revenues and expenses on the same basis as 2004 following our consolidation of SouthStar pursuant to our adoption of FIN 46R.These unaudited pro-forma amounts are presented for comparative purposes only.

AGL RESOURCES INC. AND SUBSIDIARIES
PRO-FORMA CONDENSED CONSOLIDATED BALANCE SHEET
DECEMBER 31, 2003
(UNAUDITED)

In millions	As reported	SouthStar	Eliminations	Pro-forma
Current assets	$742	$174	($11)	$905
Property, plant and equipment	2,352	2	-	2,354
Deferred debits and other assets (1)	878	-	(71)	807
Total assets	$3,972	$176	($82)	$4,066
Current liabilities	$1,048	$75	($11)	$1,112
Accumulated deferred income taxes	376	-	-	376
Long-term liabilities	569	-	-	569
Deferred credits	77	-	-	77
Minority interest	-	-	30	30
Capitalization	1,902	101	(101)	1,902
Total liabilities and capitalization	$3,972	$176	($82)	$4,066

(1) Our investment in SouthStar was $71 million.

AGL RESOURCES INC. AND SUBSIDIARIES
PRO-FORMA CONDENSED CONSOLIDATED STATEMENT OF INCOME
FOR THE THREE MONTHS ENDED JUNE 30, 2003
(UNAUDITED)

In millions	As reported	SouthStar (1)	Eliminations	Pro-forma
Operating revenues	$187	$136	($41)	$282
Operating expenses				
Cost of gas	46	109	(41)	114
Operation and maintenance expenses	70	14	-	84
Depreciation and amortization	23	-	-	23
Taxes other than income	7	-	-	7
Total operating expenses	146	123	(41)	228
Operating income	41	13	-	54
Equity earnings from SouthStar	10	-	(10)	-
Other income	(2)	-	-	(2)
Interest expense	(18)	-	-	(18)
Minority interest in income of consolidated subsidiary (2)	-	-	(3)	(3)
Earnings before income taxes	31	13	(13)	31
Income taxes	12	-	-	12
Income before cumulative effect of change in accounting principle	19	13	(13)	19

(1) Includes 100% of SouthStar's revenues and expenses for comparisons among 2003 and 2004 quarters adjusted for SouthStar's consolidation in 2004.
(2) Minority interest adjusts our earnings to reflect our 70% share of SouthStar's earnings (less Dynegy Inc.'s 20% share of SouthStar's income prior to February 18, 2003).

AGL RESOURCES INC. AND SUBSIDIARIES
PRO-FORMA CONDENSED CONSOLIDATED STATEMENT OF INCOME
FOR THE SIX MONTHS ENDED JUNE 30, 2003
(UNAUDITED)

In millions	As reported	SouthStar (1)	Eliminations	Pro-forma
Operating revenues	$539	$428	($90)	$877
Operating expenses				
Cost of gas	194	355	(90)	459
Operation and maintenance expenses	142	32	-	174
Depreciation and amortization	45	1	-	46
Taxes other than income	15	-	-	15
Total operating expenses	396	388	(90)	694
Operating income	143	40	-	183
Equity earnings from SouthStar	24	-	(24)	-
Other income	-	-	-	-
Interest expense	(38)	-	-	(38)
Minority interest in income of consolidated subsidiary (2)	-	-	(16)	(16)
Earnings before income taxes	129	40	(40)	129
Income taxes	50	-	-	50
Income before cumulative effect of change in accounting principle	79	40	(40)	79

(1) Includes 100% of SouthStar's revenues and expenses for comparisons among 2003 and 2004 quarters adjusted for SouthStar's consolidation in 2004.
(2) Minority interest adjusts our earnings to reflect our 70% share of SouthStar's earnings (less Dynegy Inc.'s 20% share of SouthStar's income prior to February 18, 2003).

Corporate

Our corporate segment includes the results of operations and financial condition of our nonoperating business units, including AGL Services Company (AGSC) and AGL Capital Corporation (AGL Capital). AGSC is a service company established in accordance with the Public Utility Holding Company Act of 1935, as amended (PUHCA). AGL Capital provides for our ongoing financing needs through a commercial paper program, the issuance of various debt and hybrid securities, and other financing arrangements.

We allocate substantially all of AGSC's and AGL Capital's operating expenses and interest costs to our operating segments in accordance with PUHCA and state regulations. Our corporate segment also includes intercompany eliminations for transactions between our operating business segments.

In August 2003, we formed Pivotal Energy Development (Pivotal) within AGSC. Pivotal coordinates, among our related operating segments, the development, construction or acquisition of assets in the Southeast and Mid-Atlantic regions in order to extend our natural gas capabilities and improve system reliability while enhancing service to our customers in those areas. The initial focus of Pivotal's commercial activities will be to improve the economics of system reliability and natural gas deliverability in these targeted regions.

Results of operations for the three and six months ended June 30, 2004 and 2003 are as follows:

	Three months ended June 30,			**Six months ended June 30,**		
In millions	**2004**	**2003**	**2004 vs. 2003**	**2004**	**2003**	**2004 vs. 2003**
Total operating expenses	1	1	-	4	1	3
Operating (loss) income	(1)	(1)	-	(4)	(1)	(3)
Other loss	(1)	(1)	-	(1)	(1)	-
EBIT	($2)	($2)	$-	($5)	($2)	($3)

(1) Reflects the elimination of intercompany profits between segments.

2nd Quarter 2004 compared to 2nd Quarter 2003 Our corporate segment's EBIT year over year remain unchanged. Excluding allocations, operating expenses increased from $33 million in 2003 to $35 million in 2004, an increase of $8 million. This increase was offset by the allocation of expenses to the three operating segments. Operating expenses increased primarily as a result of higher long-term incentive compensation, an increase in costs associated with software maintenance, licensing and implementation projects, consulting and outside services costs related to our Sarbanes-Oxley Act compliance efforts, and expenses related to Pivotal's activity which was established in the fourth quarter of 2003. These increases were partially offset by lower legal and facility costs.

6 months 2004 compared to 6 months 2003 The decrease in EBIT of $3 million was the result of increased operating expenses of $7 million offset partially by increases in allocations of $4 million. Excluding allocations, operating expenses for the six months were $77 million, as compared to $70 million in the same period last year. The increase of $7 million was due primarily to costs associated with software maintenance, licensing and implementation projects, a loss on the retirement of information services and facilities assets, and higher outside consulting costs due in part to our Sarbanes-Oxley Act compliance efforts. In addition, the increase was partially due to expenses related to Pivotal's activities in 2004.

Liquidity and Capital Resources

Known Trends and Uncertainties We rely on operating cash flow; short-term borrowings under our commercial paper program, which is backed by our supporting credit agreement (Credit Facility); and borrowings or stock issuances in the long-term capital markets to meet our capital and liquidity requirements. 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. On April 1, 2004 we received approval from the SEC under the PUHCA for the renewal of our financing authority to issue securities through April 2007.

On May 26, 2004, we closed on a new $500 million three-year Credit Facility. This new Credit Facility replaces our previous $200 million 364-day Credit Facility which was scheduled to expire on June 16, 2004 and our previous $300 million three-year Credit Facility that was scheduled to terminate on August 7, 2005. Under our new Credit Facility, one time each calendar year we can request from lenders an increase in credit commitments up to an additional $200 million. The availability of borrowings and unused availability under our Credit Facility is limited and subject to conditions specified within the Credit Facility, which we currently meet. These conditions specified within the Credit Facility include:

- compliance with certain financial covenants
- the continued accuracy of representations and warranties contained in the agreements, and
- our total debt-to-capital ratio

Our total cash and available liquidity under our Credit Facility at June 30, 2004, December 31, 2003 and June 30, 2003 is represented in the table below.

In millions	June 30, 2004	Dec. 31, 2003	June 30, 2003
Unused availability under the Credit Facility	$500	$500	$500
Cash and cash equivalents	54	17	3
Total cash and available liquidity under the Credit Facility	$554	$517	$503

For the future, we believe these sources will be sufficient for our working capital needs, debt service obligations and scheduled capital expenditures. The relatively stable operating cash flows of our distribution operations businesses currently contribute a substantial portion of our cash flow from operations and we anticipate this to continue in the future. However, our liquidity and capital resource requirements may change in the future due to a number of 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
- regulatory changes and changes in rate-making policies of regulatory commissions
- contractual cash obligations and other commercial commitments
- interest rate changes
- pension and postretirement benefit costs
- changes in income tax laws
- changes in wholesale prices and customer demand for our products and services
- margin requirements resulting from significant increases or decreases in our commodity prices
- operational risks
- the anticipated debt and equity financings associated with our acquisition of NUI

Seasonality The seasonal nature of our sales affects the comparison of certain balance sheet items at June 30, 2004 and at December 31, 2003, such as receivables, unbilled revenue, inventories, and short-term debt. We have presented the condensed consolidated balance sheet as of June 30, 2003 to provide comparisons of these items with the corresponding period of the preceding year.

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.

Contingent financial commitments represent obligations that become payable only if certain pre-defined 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 tables illustrate our expected future contractual cash obligations and commitments as of June 30, 2004:

			Payments Due before December 31,		
In millions	Total	2004	2005 & 2006	2007 & 2008	2009 & Thereafter
Long-term debt (1)	$962	-	-	-	$962
Pipeline charges, storage capacity and gas supply (2)	719	134	271	124	190
Pipeline replacement program costs (3)	375	48	166	161	-
Short-term debt	195	195	-	-	-
ERC (3)	62	15	31	6	10
Operating leases (4)	79	6	22	16	35
Communication/network service and maintenance	16	5	11	-	-
Total	$2,408	$403	$501	$307	$1,197

(1) Includes $234 million of Notes Payable to Trusts, callable in 2006 and 2007.
(2) Charges recoverable through a PGA mechanism or alternatively billed to Marketers.
(3) Charges recoverable through rate rider mechanisms.
(4) We have certain operating leases with provisions for step rent or escalation payments, or 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.

			Commitments Due before December 31,		
In millions	Total	2004	2005 & 2006	2007 & 2008	2009 & Thereafter
Guarantees (1) (2)	$277	$277	$-	$-	$-
Standby letters of credit, performance/ surety bonds	11	9	2	-	-
Total other commercial commitments	$288	$286	$2	$-	$-

(1) $228 million of these guarantees support credit exposures in Sequent's energy marketing and risk management business. In the event that Sequent defaults on any commitments under these guarantees, these amounts would become payable by us as guarantor.
(2) We provide guarantees on behalf of our subsidiary, SouthStar. We guarantee 70% of SouthStar's obligations to SNG under certain agreements between the parties up to a maximum of $7 million if SouthStar fails to make payment to SNG. Under a second such guarantee, we guarantee 70% of SouthStar's obligations to AGLC under certain agreements between the parties up to a maximum of $42 million, which represents our share of SouthStar's maximum credit support obligation to AGLC under its tariff.

Cash flow provided from operating activities Our statement of cash flows is prepared using the indirect method. Under this method, net income is reconciled to cash flows from operating activities by adjusting net income for those items that impact net income but do not result in actual cash receipts or payments during the period. These reconciling items include depreciation, undistributed earnings from equity investments, changes in deferred income taxes, gains or losses on the sale of assets and changes in the balance sheet for working capital from the beginning to the end of the period.

Our operating cash flows for the six months ended June 30, 2004 include SouthStar's operating cash flows of approximately $93 million as a result of our consolidation of SouthStar effective January 1, 2004; however in 2003, our operating cash flow did not include any amounts from SouthStar consistent with the equity method of accounting since no distributions were received from SouthStar. Year-to-year changes in our operating cash flows, excluding SouthStar, are primarily the result of the following:

- changes in our operating results
- the timing associated with working capital items such as cash collections from our customers and cash receipts or disbursements for our natural gas inventories
- payments for operating expenses to our vendors and employees, income taxes and interest

We generate a large portion of our annual net income in the first and fourth quarters due to significant volumes of natural gas that are delivered by distribution operations and SouthStar to our customers during the November-to-March heating season which increases our accounts receivable. In addition, during this period our accounts payable increases to reflect payments due to providers of the natural gas commodity and pipeline capacity. The value of the natural gas commodity can vary significantly from one period to the next as a result of the volatility in the price of natural gas. Natural gas costs and deferred purchased natural gas costs due from or to our customers represent the difference between natural gas costs that have been paid to suppliers in the past and what has been collected from customers. These natural gas costs can cause significant variations in cash flows from period to period. Finally, our natural gas inventories, which usually peak on November 1, are largely drawn down in the heating season, and provide a source of cash as this asset is used to satisfy winter sales demand.

Our cash flow from operations for the six months ended June 30, 2004 was $344 million, an increase of $139 million from the same period in 2003. The increase is a result of the impact of consolidation of SouthStar of $93 million, higher net income and decreased working capital requirements. In addition, following the heating season, our cash flow from operations for both the six months ended June 30, 2004 and 2003 was positively impacted by cash received from the collection of our customer's balances from the heating season. The increase was offset slightly by the cost associated with our net injections of natural gas inventories to replenish the heating season withdrawals.

Cash flow used in investing activities Our cash used in investing activities consists primarily of property, plant and equipment expenditures. As shown in the following table, we made investments of $104 million in the six months ended June 30, 2004 and $77 million in the same period in 2003.

In millions	**2004**	**2003**	**2004 vs. 2003**
Construction of distribution facilities	$28	$27	$1
Pipeline replacement program (1)	39	19	20
Pivotal propane plant	10	-	10
Telecommunications	-	6	(6)
Other	27	25	2
Total property, plant and equipment expenditures	104	77	27
Environmental response costs (2)	21	16	5
Total capital requirements	$125	$93	$32

(1) These expenditures include removal costs. Capital expenditures under this program are expected to end June 30, 2008, unless the program is extended by the GPSC.

(2) These costs are not included in our cash flows used in investing activities as they are not considered property, plant and equipment expenditures. They are considered a component of our capital requirements as we estimate our cash requirements for future years.

The increase of $32 million is primarily from higher expenditures at our distribution operations segment, including higher expenditures at AGLC and Pivotal Propane. The increase at AGLC includes a $20 million increase in the pipeline replacement program (PRP) as a result of larger diameter and more expensive pipe that has been replaced this year. In addition, the increase at Pivotal Propane of $10 million relates to expenditures for the construction of a propane plant in the VNG service area.

These increases were offset by decreased expenditures at AGL Networks of $6 million as a result of the completion of our initial Atlanta and Phoenix networks in 2003. In 2004, our investing activities also consisted of $31 million in cash receipts for the sale of our interests in US Propane. In 2003, we made a payment of $20 million for the purchase of Dynegy's 20% interest in SouthStar.

Cash flow used in financing activities In the six months ended June 30, 2004 and 2003, our cash used in financing activities are primarily composed of borrowings and payments of short-term debt, payments of Medium-Term notes, cash dividends on our common stock and the issuance of common stock. Our Credit Facility financial covenants and the PUHCA's order require us to maintain a ratio of total debt-to-total capitalization of no greater than 70.0%. As of June 30, 2004, we were in compliance with this leverage ratio requirement. We have a goal to maintain our common equity ratio in the 40 - 50 percent range of total capitalization.

Our payments for natural gas and pipeline capacity are generally made to suppliers prior to the collection of accounts receivable from our customers. This results in our short-term debt financing generally increasing between September 30 and March 31. In addition, we typically reduce short-term debt balances in the spring because a significant portion of our current assets are converted into cash at the end of the winter heating season.

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

Dollars in millions	June 30, 2004		December 31, 2003		June 30, 2003	
Short-term debt	$161	7%	$306	13%	$147	7%
Current portion of long-term debt	34	2	77	3	95	5
Senior and Medium-Term notes (1)	728	33	731	32	697	34
Note payable to capital trust (1	234	11	-	-	-	-
Trust Preferred Securities (1)	-	-	225	10	228	11
Total debt	1,157	53	1,339	58	1,167	57
Minority interest	29	1	-	-	-	-
Common equity	1,011	46	946	42	897	43
Total capitalization	$2,197	100%	$2,285	100%	$2,064	100%

(1) Net of interest rate swaps

Short-term debt Our short-term debt is composed of borrowings under our commercial paper program, Sequent's line of credit and SouthStar's line of credit. The decrease in our short-term debt of $145 million is primarily a result of payments on outstanding commercial paper from:

- cash generated from strong operating results
- positive working capital from lower receivable and inventory requirements
- proceeds from the sale of our ownership interest in US Propane
- receipt of cash from SouthStar in the time period of December 2003 through June 2004

Long-term Debt For the six months ended June 30, 2004, we made $49 million in Medium-Term note payments, as follows:

- In January, 2004, we exercised our option to redeem $44 million at a call premium. These notes were scheduled to mature in 2019 with interest rates ranging from 7.0% to 7.1%
- In February 2004, we exercised our option to redeem $5 million at a call premium. This note was scheduled to mature in 2014 with a interest rate of 7.0%

Minority interest SouthStar's accounts have been combined with our subsidiaries' accounts as of or for the six months ended June 30, 2004. As a result, we recorded Piedmont's portion of SouthStar's contributed capital as minority interest on our condensed consolidated balance sheet and is included as a component of our capitalization. In addition, we recorded a cash disbursement of $14 million in our cash flows from financing activities for SouthStar's dividend distribution to Piedmont.

Interest Rate Swaps To maintain an effective capital structure, it is our policy to borrow funds using a mix of fixed-rate debt and variable-rate debt. We have entered into interest rate swap agreements, for the purpose of hedging the interest rate risk associated with our fixed-rate and variable-rate debt obligations. Including the effects of our interest rate swaps, 71% of our total short-term and long-term debt was fixed. For more discussion of our interest rate swaps, see Note 3, "Risk Management."

Credit rating As a result of the announcement of our definitive agreement to acquire NUI, which includes the assumption of approximately $607 million of NUI's debt, the outlooks on our credit ratings have changed. Moody's Investor Service recently affirmed our ratings and changed its rating outlook to negative from stable. Both Standard & Poor's Ratings Services and Fitch Ratings placed our credit ratings on watch status with negative outlooks.

These rating agencies have indicated their actions are the result of the execution risks in consummating, financing and integrating the NUI acquisition and certain closing conditions that must be met by NUI. The execution risks include obtaining regulatory approvals and the capital market risk related to the successful completion of equity and debt financing around the acquisition closing, mitigating our increased leverage. The closing conditions include NUI's obtaining additional liquidity lines, obtaining a favorable rate order from the New Jersey Board of Public Utilities (NJBPU), and assurances that issues raised in an audit of NUI by the NJBPU and ongoing investigations are resolved.

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 based 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 for the year ended December 31, 2003 and includes the following:

- Regulatory Accounting
- Pipeline Replacement Program
- Environmental Response Costs
- Revenue Recognition
- Accounting for Contingencies
- Accounting for Pension 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. The following represent significant changes in our critical accounting policies during the six months ended June 30, 2004:

Derivatives and Hedging Activities

SFAS 133, as updated by SFAS 149, established accounting and reporting standards requiring that every derivative financial instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or liability measured at its fair value. However, if the derivative transaction qualifies for and is designated as a normal purchase and sale, it is exempted from the fair value accounting treatment of SFAS 133, as updated by SFAS 149, and is accounted for using traditional accrual accounting.

SFAS 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. If the derivatives meet those criteria, SFAS 133 allows a derivative's gains and losses to offset related results on the hedged item in the income statement in the case of a fair value hedge, or to record the gains and losses in other comprehensive income until maturity in the case of a cash flow hedge. Additionally, SFAS 133 requires that a company formally designate a derivative as a hedge as well as document and assess the effectiveness of derivatives associated with transactions that receive hedge accounting treatment. Two areas where SFAS 133 applies are interest rate swaps and gas commodity contracts at both Sequent and SouthStar. Our derivative and hedging activities are described in further detail in Note 3 to the condensed consolidated financial statements.

Interest rate swaps We designate our interest rate swaps as fair value hedges as defined by SFAS 133, which allows us to designate derivatives that hedge exposure to changes in the fair value of a recognized asset or liability. We record the gain or loss on fair value hedges in earnings in the period of change, together with the offsetting loss or gain on the hedged item attributable to the risk being hedged. The effect of this accounting is to reflect in earnings only that portion of the hedge that is not effective in achieving offsetting changes in fair value.

Commodity-related derivative instruments We are exposed to risks associated with changes in the market of natural gas. Through Sequent and SouthStar, we use derivative instruments to reduce our exposure to the risk of changes in the prices of natural gas. When the portfolio market value changes, primarily due to newly originated transactions and the effect of price changes, Sequent recognizes the change in value of derivative instruments as an unrealized gain or loss in revenues in the period of change. Sequent recognizes cash inflows and outflows associated with the settlement of these risk management activities in operating cash flows, and Sequent reports these settlements as receivables and payables separately from risk management activities in the balance sheet as energy marketing receivables and trade payables.

Under our risk management policy, we attempt to mitigate substantially all of our commodity price risk associated with Sequent's storage gas portfolio and lock in the economic margin at the time we enter into gas purchase transactions for our stored gas. We purchase gas for storage when the current market price we pay for gas plus the cost to store the gas is less than the market price we could receive in the future by selling NYMEX futures contracts in the forward months, resulting in a positive net profit margin. We use contracts to sell gas at that future price to substantially lock in the profit margin we will ultimately realize when the stored gas is actually sold. These contracts meet the definition of a derivative under SFAS 133.

The purchase, storage and sale of natural gas is accounted for differently than the derivatives we use to mitigate the commodity price risk associated with our storage portfolio. The difference in accounting can result in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated. We do not currently use hedge accounting under SFAS 133 to account for this activity.

Gas that we purchase and inject into storage is accounted for on an accrual basis, at the lower of average cost or market, as inventory in our consolidated balance sheets and is no longer marked to market following our implementation of the accounting guidance in EITF 02-03. Under current accounting guidance, we would recognize a loss in any period when the market price for gas is lower than the carrying amount for our purchased gas inventory. Costs to store the gas are recognized in the period the costs are incurred. We recognize revenues and cost of gas sold in our statement of consolidated income in the period we sell gas and it is delivered out of the storage facility.

The derivatives we use to mitigate commodity price risk and substantially lock in the margin upon the sale of stored gas are accounted for at fair value and marked to market each period, with changes in fair value recognized as unrealized gains or losses in the period of change. This difference in accounting, the accrual basis for our gas storage inventory versus mark-to-market accounting for the derivatives used to mitigate commodity price risk, can result in volatility in our reported net income. Based upon Sequent's storage positions at June 30, 2004, a $0.10 forward NYMEX change would result in $0.6 million impact to Sequent's EBIT.

Over time, gains or losses on the sale of gas storage inventory will be offset by losses or gains on the derivatives, resulting in realization of the economic profit margin we expected when we entered into the transactions. This accounting difference causes Sequent's earnings on its storage gas positions to be affected by natural gas price changes, even though the economic profits remain essentially unchanged. Sequent manages underground storage for our utilities and holds certain capacity rights on its own behalf. The underground storage is of two types:

- reservoir storage, where supplies are generally injected and withdrawn on a seasonal basis
- salt dome high-deliverability storage, where supplies may be periodically injected and withdrawn on relatively short notice

SouthStar also uses derivative instruments to manage exposures arising from changing commodity prices. SouthStar's objective for holding these derivatives is to minimize this risk using the most effective methods to reduce or eliminate the impacts of these exposures. A significant portion of SouthStar's derivative transactions are designated as cash flow hedges under SFAS 133. Derivative gains or losses arising from cash flow hedges are recorded in other comprehensive income (OCI) and are reclassified into earnings in the same period as the settlement of the underlying hedged item. Any hedge ineffectiveness, defined as when the gains or losses on the hedging instrument do not perfectly offset the losses or gains on the hedged item, is recorded into earnings in the period in which it occurs. SouthStar currently has no hedge ineffectiveness. The remainder of SouthStar's derivative instruments does not meet the hedge criteria under SFAS 133. Therefore, changes in their fair value are recorded in earnings in the period of change.

Weather derivative contracts SouthStar routinely enters into weather derivative contracts for hedging purposes in order to preserve margins in the event of warmer-than-normal weather in the winter months. SouthStar accounts for these contracts using the intrinsic value method under the guidelines of EITF 99-02, "Accounting for Weather Derivatives".

Accounting Developments

FASB Staff Position 106-1 Effective December 8, 2003, the "Medicare Prescription Drug, Improvement and Modernization Act of 2003" (Medicare Prescription Drug Act) was signed into law, which provides for a prescription drug benefit under Medicare (Part D) as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. Our defined benefit postretirement health care and life insurance plans do provide a prescription drug benefit.

On January 12, 2004, the FASB issued FASB Staff Position (FSP) 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" (FSP 106-1), which allowed companies to elect a one-time deferral of the recognition of the effects of the Medicare Prescription Drug Act in accounting for their plans under SFAS 106 and in providing disclosures related to the plan required by SFAS 132 (revised 2003). The FASB allowed the one-time deferral due to the accounting issues raised by the Medicare Prescription Drug Act--in particular, the accounting for the federal subsidy that is not explicitly addressed in SFAS 106--and due to the fact that uncertainties exist as to the direct effects of the Medicare Prescription Drug Act and its ancillary effects on plan participants.

For companies electing the one-time deferral, such deferral remains in effect until authoritative guidance on the accounting for the federal subsidy is issued, or until certain other events, such as a plan amendment, settlement or curtailment, occur. As of December 31, 2003, we elected the one-time deferral. Our accumulated postretirement obligation or net periodic postretirement benefit cost for 2003 and 2004 does not reflect the effects of the Medicare Prescription Drug Act on our other postretirement plan since specific authoritative guidance on the accounting for the federal subsidy has not been issued and we have not made any amendments to our postretirement plan. Once specific authoritative guidance on the accounting for the federal subsidy is issued, it could result in a change to previously reported information.

FASB Staff Position 106-2 On May 19, 2004, the FASB issued FSP 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," (FSP 106-2) which supersedes FSP 106-1 and is effective for the first interim or annual reporting period beginning after June 15, 2004, or July 1, 2004 for us. The guidance in FSP 106-2 related to the accounting for the federal subsidy applies only to the sponsor of a single-employer defined benefit postretirement health care plan for which (a) the employer has concluded that prescription drug benefits available under the plan to some or all participants for some or all future years are "actuarially equivalent" to Medicare Part D and thus qualify for the subsidy under the Medicare Prescription Drug Act and (b) the expected federal subsidy will offset or reduce the employer's share of the cost of the underlying postretirement prescription drug coverage on which the federal subsidy is based. FSP 106-2 also provides guidance for the disclosures about the effects of the subsidy for an employer that sponsors a postretirement health care benefit plan that provides prescription drug coverage but for which the employer has not yet been able to determine actuarial equivalency.

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 AGLC in distribution operations and in wholesale services.

Our Risk Management Committee (RMC) is responsible for the overall establishment of risk management policies and the monitoring of compliance with and adherence to the terms within these policies, including approval and authorization levels and delegation of these levels. Our RMC consists of senior executives who monitor commodity price risk positions, corporate exposures, credit exposures and overall results of our risk management activities, and is chaired by our chief risk officer, who is responsible for ensuring that appropriate reporting mechanisms exist for the RMC to perform its monitoring functions. Our risk management activities and related accounting treatment are described in further detail in Note 3 to the condensed consolidated financial statements.

Commodity Price Risk

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, option 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, 2004, December 31, 2003 and June 30, 2003. We base the average values on monthly averages for the six months ended June 30, 2004 and 12 months ended December 31, 2003.

	Asset				
	Average Values		Value at:		
In millions	6 months ended June 30, 2004	12 months ended Dec. 31, 2003	June 30, 2004	Dec. 31, 2003	June 30, 2003
Natural gas contracts	$23	$14	$23	$13	$12

	Liability				
	Average Values		Value at:		
In millions	6 months ended June 30, 2004	12 months ended Dec. 31, 2003	June 30, 2004	Dec. 31, 2003	June 30, 2003
Natural gas contracts	$15	$14	$13	$18	$11

We employ a systematic approach to the evaluation and management of the risks associated with our contracts related to wholesale marketing and risk management, including value-at-risk (VaR). VaR is defined as the maximum potential loss in portfolio value over a specified time period that is not expected to be exceeded within a given degree of probability.

We use a 1-day and a 10-day holding period and a 95% confidence interval to evaluate our VaR exposure. 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 calculate VaR based on the variance-covariance technique. This technique requires several assumptions for the basis of the calculation, such as price volatility, confidence interval and holding period. 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 is no established industry standard for calculating VaR or for the assumptions underlying such calculations.

Our 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 we generally manage physical gas assets and economically protect our positions by hedging in the futures markets, our open exposure is generally minimal, permitting us to operate within relatively low VaR limits. We employ daily risk testing, using both VaR and stress testing, to evaluate the risks of our open positions.

Our management actively monitors open commodity positions and the resulting VaR. We continue to maintain a relatively matched book, where our total buy volume is close to sell volume, with minimal open commodity risk. Based on a 95% confidence interval and employing a 1-day and a 10-day holding period for all positions, our portfolio of positions for the 6 months ended June 30, 2004 and twelve months ended December 31, 2003 had the following 1-day and 10-day holding period VaRs:

	6 months ended June 30, 2004		12 months ended December 31, 2003	
In millions	1-day	10-day	1-day	10-day
Period end (1)	$0.0	$0.0	$0.3	$1.0
Average	0.1	0.2	0.1	0.3
High	0.4	1.2	2.5	4.7
Low (1)	0.0	0.0	0.0	0.0

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

Energy Investments SouthStar's use of derivatives is governed by a risk management policy which prohibits the use of derivatives for speculative purposes. This policy also establishes VaR limits of $0.5 million on a 1-day holding period and $0.7 million on a 10-day holding period. In June 2004, the SouthStar risk management committee approved replacing the 20-day VaR limit with a 10-day VaR limit. The 10-day VaR limit was determined to be a more appropriate industry standard, and thus adopted by SouthStar. A 95% confidence interval is used to evaluate VaR exposure. The maximum VaR experienced during the six months ended June 30, 2004 was less than $0.1 million for the 1-day holding period and $0.1 million for the 10-day holding period.

Credit Risk

Sequent may require its counterparties to pledge additional collateral when deemed necessary. We conduct credit evaluations and obtain appropriate internal approvals for our 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, we require credit enhancements by way of guaranty, cash deposit or letter of credit for transaction counterparties that do not meet the minimum ratings threshold.

Sequent evaluates its counterparties using the S&P equivalent credit rating which is determined by a process of converting the lower of the S&P or Moody's Investors Service, Inc. (Moody's) rating to an internal rating ranging from 9.00 to 1.00, with 9.00 being equivalent to AAA/Aaa by S&P and Moody's and 1.00 being equivalent to 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 its financial ratios.

The weighted average credit rating is obtained by multiplying each counterparty's assigned internal rating by the counterparty's credit exposure and the individual results are then summed for all counterparties. That total is divided by the aggregate total counterparties' exposure. This numeric value is converted to an S&P equivalent. Under the refined methodology, Sequent's counterparties, or the counterparties' guarantors, had a weighted average S&P equivalent credit rating of A- at June 30, 2004, compared with our previously reported rating of BBB at December 31, 2003.

The following tables show Sequent's commodity receivable and payable positions as of June 30, 2004, December 31, 2003 and June 30, 2003:

Gross receivables

In millions	June 30, 2004	Dec. 31, 2003	June 30, 2003
Receivables with netting agreements in place:			
Counterparty is investment grade	$289	$282	$208
Counterparty is non-investment grade	20	13	24
Counterparty has no external rating	22	9	7
Receivables without netting agreements in place:			
Counterparty is investment grade	19	15	3
Counterparty is non-investment grade	-	-	-
Counterparty has no external rating	-	-	-
Amount recorded on balance sheet	$350	$319	$242

Gross payables

In millions	June 30, 2004	Dec. 31, 2003	June 30, 2003
Payables with netting agreements in place:			
Counterparty is investment grade	$215	$205	$181
Counterparty is non-investment grade	65	31	50
Counterparty has no external rating	91	45	27
Payables without netting agreements in place:			
Counterparty is investment grade	50	29	24
Counterparty is non-investment grade	-	3	9
Counterparty has no external rating	-	16	2
Amount recorded on balance sheet	$421	$329	$293

Item 4. Controls and Procedures

(a) *Evaluation of disclosure controls and procedures*. Our chief executive officer and chief financial officer, after evaluating the effectiveness of our "disclosure controls and procedures" (as defined in the Securities Exchange Act of 1934 Rules 13a-15(e) and 15d-15(e)) as of the end of the period covered by this quarterly report have concluded that our disclosure controls and procedures were effective in timely alerting them to material information relating to us (including our consolidated subsidiaries) which were required to be included in our periodic SEC filings.

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

PART II – OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

The nature of our business ordinarily results in periodic regulatory proceedings before various state and federal authorities and/or litigation incidental to the business. For information regarding pending federal and state regulatory matters, see "Results of Operation – Distribution Operations" contained in Item 2 of Part I under the caption, "Management's Discussion and Analysis of Financial Condition and Results of Operations."

In the first quarter of 2004, we settled a lawsuit with the city of Augusta, Georgia who had served AGLC with a complaint that was filed in the Superior Court of Richmond County, Georgia on July 1, 2003. The City of Augusta's allegations included fraud and deceit and damages to realty. The allegations arose from negotiations between the city and AGLC regarding the environmental cleanup obligations connected with AGLC's former MGP operations in Augusta. For more information about our manufactured gas plants and our environmental cleanup obligations, please see Item 1, Financial Statements, Note 4 "Regulatory Assets and Liabilities – Environmental Response Costs."

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. CHANGES IN SECURITIES, USE OF PROCEEDS AND ISSUER PURCHASES OF EQUITY SECURITIES

The following table sets forth our common stock repurchases for the periods indicated. All shares were purchased in open market transactions in connection with awards dominated in common stock under the AGL Resources Inc. Officer Incentive Plan (OIP).

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
Prior Years	**62,740**	**$25.46**	**62,740**	**537,260**
January 1, 2004 – January 31, 2004	-	-	-	537,260
February 1, 2004 – February 29, 2004	-	-	-	537,260
March 1, 2004 – March 31, 2004	20,000	$28.10	20,000	517,260
Total first quarter	**20,000**	**$28.10**	**20,000**	**517,260**
April 1, 2004 – April 30, 2004	-	-	-	517,260
May 1, 2004 – May 31, 2004	-	-	-	517,260
June 1, 2004 – June 30, 2004	-	-	-	517,260
Total second quarter	**-**	**-**	**-**	**517,260**
Total all periods	**82,740**	**$25.99**	**82,740**	**517,260**

(1) On June 30, 2001, we disclosed that our board of directors approved the repurchase of up to 600,000 shares of our common stock to be used for the OIP. In March 2004, 20,000 shares were repurchased under this plan. As of June 30, 2004 a total of 82,740 shares have been repurchased leaving a maximum of 517,260 shares that can still be repurchase under the OIP.

PART II -- OTHER INFORMATION - Continued

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

We held our annual meeting of shareholders in Atlanta, Georgia on April 28, 2004. Holders of an aggregate of 64,640,492 shares of our common stock at the close of business on February 20, 2004 were entitled to vote at the meeting, of which 55,554,590 were represented in person or by proxy. At the annual meeting, our shareholders were presented with one proposal as set forth in our Proxy Statement. Our shareholders voted as follows and elected the following five director nominees who will serve a three-year term until our Annual Meeting in 2007.

	For	Withheld
Thomas D. Bell, Jr. (1)	52,461,967	3,092,623
Michael J. Durham	53,695,992	1,858,598
D. Raymond Riddle	53,663,031	1,891,559
Felker W. Ward, Jr.	54,210,955	1,343,635
Henry C. Wolf	54,137,296	1,417,294

(1) On April 28, 2004, we filed a Form 8-K disclosing that Mr. Bell had resigned from our Board of Directors, and if elected at our annual meeting would decline to serve as a director.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

(a) Exhibits

10.1 Three year Credit Agreement dated May 26, 2004, by and between AGL Resources Inc., as Guarantor, AGL Capital Corporation, as Borrower, and the Lenders named therein.

10.2 Continuity Agreement, dated December 1, 2003, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Melanie M. Platt.

10.3 Form of Director Indemnification Agreement, dated April 28, 2004, between AGL Resources Inc., on behalf of itself and the Indemnites named therein.

31 Rule 13a-14(a) / 15d-14(a) Certifications

32 Section 1350 Certifications

(b) Reports on Form 8-K.

Date	Event Reported
April 28, 2004	Filed under Item 5 “Other Events”
April 28, 2004	Furnished under Item 9 “Regulation FD Disclosure”
April 28, 2004	Furnished under Item 12 “Results of Operation and Financial Condition”

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: July 28, 2004	/s/ Richard T. O'Brien Executive Vice President and Chief Financial Officer