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

FORM 10-K

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

For the fiscal year ended December 31, 2003 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	**404-584-4000**
(Address and zip code of principal executive offices)	(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Class	Name of exchange on which registered
Common Stock, $5 Par Value	**New York Stock Exchange**
Preferred Share Purchase Rights	**New York Stock Exchange**
8% Trust Preferred Securities	**New York Stock Exchange**

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, and (2) has been subject to such filing requirements for the past 90 days. Yes __X__ No _____

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

Indicate by check mark whether the registrant is an accelerated filer (as defined in rule 12b-2 of the Act). Yes __X__ No ____

Aggregate market value of voting and non-voting shares of Common Stock held by non-affiliates of the registrant, computed by reference to the closing price of such stock as of June 30, 2003: $1,617,913,938

The number of shares of Common Stock outstanding as of January 20, 2004 was 64,586,932 shares.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the Proxy Statement for the 2004 Annual Meeting of Shareholders ("Proxy Statement") to be held April 28, 2004, are incorporated by reference in Part III.

TABLE OF CONTENTS

TABLE OF CONTENTS – continued

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 and AGL Capital
Credit Facility	Credit agreements 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, donations and gain on sales of assets and 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
GAAP	Accounting principles generally accepted in the United States of America
GPSC	Georgia Public Service Commission
Heritage	Heritage Propane Partners, L.P.
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 5.9% to 8.7%
MGP	Manufactured gas plant
NYMEX	New York Mercantile Exchange, Inc.
OCI	Other comprehensive income
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
PBR	Performance-based rate plan
PGA	Purchased gas adjustment
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.
SFAS	Statement of Financial Accounting Standards
SouthStar	SouthStar Energy Services LLC
Trust Preferred Securities	Trust preferred securities subject to mandatory redemption
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”
EITF 98-10	Emerging Issues Task Force (EITF) Issue No. 98-10, “Accounting for Contracts Involved in Energy Trading and Risk Management Activities”
EITF 99-02	Emerging Issues Task Force Issue No. 99-02, “Accounting for Weather Derivatives”
EITF 00-11	Emerging Issues Task Force Issue No. 00-11, “Lessors’ Evaluation of Whether Leases of Certain Integral Equipment Meet the Ownership Transfer Requirements of FASB Statement No. 13, *Accounting for Leases*, for Leases of Real Estate”
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 45	FASB Interpretation No. (FIN) 45, “Guarantor’s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others”
FIN 46	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”
SFAS 5	SFAS No. 5, “Accounting for Contingencies”
SFAS 13	SFAS No. 13, “Accounting for Leases”
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 87	SFAS No. 87, “Employers’ Accounting for Pensions”
SFAS 88	SFAS No. 88, “Employers’ Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits”
SFAS 106	SFAS No. 106, “Employers’ Accounting for Postretirement Benefits Other than Pensions”
SFAS 109	SFAS No. 109, “Accounting for Income Taxes”
SFAS 121	SFAS No. 121, “Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of”
SFAS 123	SFAS No. 123, “Accounting for Stock-Based Compensation”
SFAS 132	SFAS No. 132, “Employers’ Disclosures about Pensions and Other Postretirement Benefits-an amendment of FASB Statements No. 87, 88 and 106”
SFAS 133	SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities”
SFAS 142	SFAS No. 142, “Goodwill and Other Intangible Assets”
SFAS 143	SFAS No. 143, “Accounting for Asset Retirement Obligations”
SFAS 144	SFAS No. 144, “Accounting for the Impairment or Disposal of Long-Lived Assets”
SFAS 148	SFAS No. 148, “Accounting for Stock-Based Compensation-Transition and Disclosure-an amendment of FASB Statement No. 123”
SFAS 149	SFAS No. 149, “Amendment of Statement 133 on Derivative Instruments and Hedging Activities”
SFAS 150	SFAS No. 150, “Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity”

PART I

ITEM 1. BUSINESS

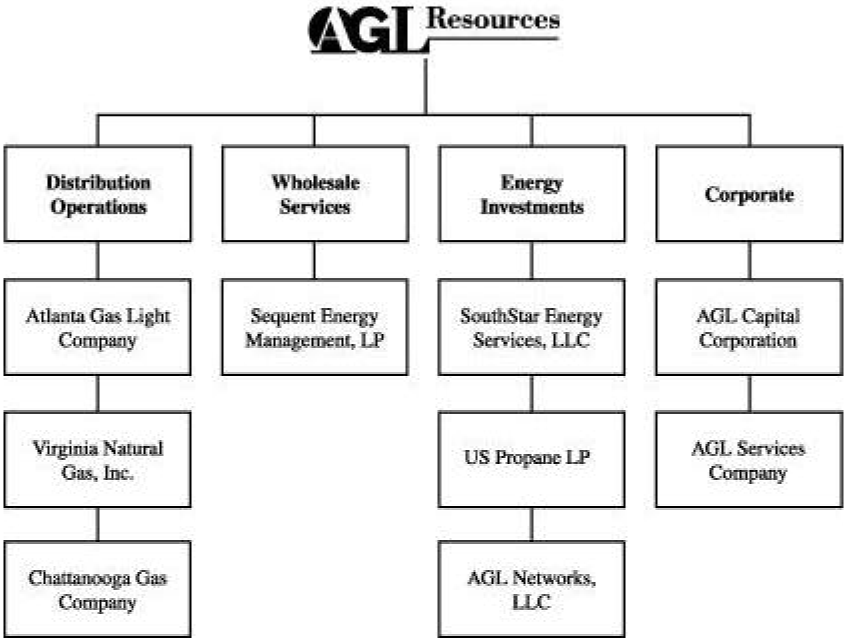
CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

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 in 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, including Atlanta Gas Light Company's (AGLC's) performance-based rate plan (PBR)
- the ultimate impact of the Sarbanes-Oxley Act of 2002 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 postretirement funding costs
- impact of acquisitions and divestitures
- 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

Nature of Our Business

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 principal executive offices are located at Ten Peachtree Place, 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 subsidiaries or affiliated companies, which we manage as three operating segments--distribution operations, wholesale services and energy investments--and one nonoperating segment, corporate, which includes intercompany eliminations.



Distribution operations includes three utilities that together serve approximately 1.8 million end-use customers, of which approximately 83% 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 and propane marketing and operating telecommunications conduit and fiber infrastructure within select metropolitan areas.

Our overall business strategy is to operate and grow our gas distribution operations 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.

Financial Information about Our Segments

For additional information on our segments, see Item 8, "Financial Statements and Supplementary Data" under Note 14, "Segment Information."

Seasonality of Business

For information on the seasonality of our operating segments' business, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under "Results of Operations."

Significant Customers

Information relating to significant customers is contained in Item 8, "Financial Statements and Supplementary Data" under Note 3, "Risk Management" under "Concentration of Credit Risk" and also in Item 7.(A), "Qualitative and Quantitative Disclosures about Market Risk" under "Credit Risk."

Employees

On December 31, 2003, we had approximately 2,150 employees compared with approximately 2,220 at December 31, 2002 and approximately 2,300 at December 31, 2001. In 2003, we completed negotiations that resulted in a new collective bargaining agreement with the Local 528 Teamsters in Georgia. We have not experienced any work stoppages between 2000 and 2003 and believe that our employee relations are good. The following table summarizes the approximate number of our employees covered under collective bargaining agreements and the date these agreements expire:

	Approximate # of Employees	Date of Contract Expiration
Teamsters	320	March 2006
Utility Workers Union of America	35	April 2004
International Union of Operating Engineers	33	September 2004
International Brotherhood of Electrical Workers	153	May 2005
Total	541	

Other Information about Our Business

The remainder of the information required by Item 1 is contained in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under "Results of Operations" and "Liquidity and Capital Resources" and also in Item 7 under "Critical Accounting Policies" under "Environmental Response Cost."

Information on regulation, gas supply and business development is contained in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under "Results of Operations."

Available Information

A copy of this Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to such reports are available free of charge on the Internet at our website www.aglresources.com as soon as reasonably practicable after we electronically file such reports with, or furnish such reports to, the SEC. The information contained on our website does not constitute incorporation by reference of the information contained on the website and should not be considered part of this document. We will also furnish copies of such reports free of charge upon written request to our Investor Relations department.

Additionally, our corporate governance guidelines; our code of ethics; our code of business conduct; and the charters of our Board committees, including the audit, compensation and management development, corporate responsibility, executive, finance and risk management, and nominating and corporate governance committees, are available on our website. We will also furnish copies of such information free of charge upon written request to our Investor Relations department.

You can contact our Investor Relations department at:

AGL Resources Inc.
Investor Relations
Dept. 1071
Ten Peachtree Place
Atlanta, GA 30309
404-584-3801

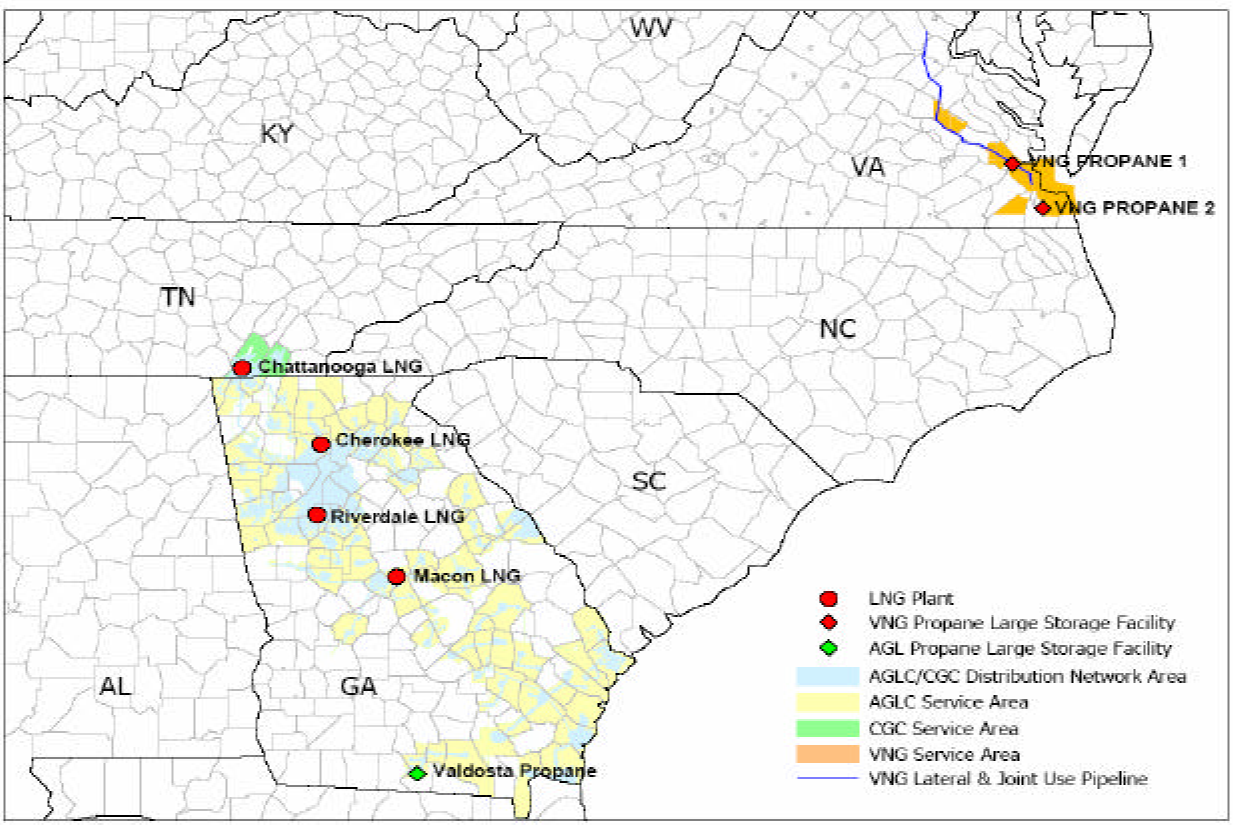
ITEM 2. PROPERTIES

We own or lease office, warehouse and other facilities throughout our operating areas, which include most of Georgia; southeastern Virginia; southeastern Tennessee; Houston, Texas; and Phoenix, Arizona. We consider our properties and the properties of our subsidiaries to be well maintained, in good operating condition and suitable for their intended purpose. We expect additional or substitute space to be available as needed to accommodate expansion of our operations. Our assets consist primarily of our investment in our subsidiaries, the principal properties of which are described below.

Distribution Operations As of December 31, 2003, the properties at distribution operations represented approximately 95% of the capitalized assets on our consolidated balance sheets. This property primarily includes assets used for the distribution of natural gas to our customers in our service areas, including approximately 34,900 miles of distribution mains, 855 miles of transportation mains and approximately 1.8 million services (which represent the pipeline connections to our customers). We have approximately 7.2 billion cubic feet (Bcf) of liquefied natural gas (LNG) storage capacity in four LNG plants located in Georgia and Tennessee. In addition, we have three propane storage facilities in Virginia and Georgia that have a combined capacity of approximately 4.5 million gallons. These LNG plants and propane facilities supplement the gas supply during peak usage periods.

In 2003, we announced the formation of Pivotal Energy Development (Pivotal). Pivotal will coordinate among our operating companies the development, construction or acquisition of assets in the Southeast and Mid-Atlantic regions that extend our natural gas capabilities and improve our systems reliability, while enhancing service to our customers in those areas. In 2004, Pivotal intends to complete the construction of a propane facility in Virginia Natural Gas's (VNG) service territory. Pivotal will provide VNG with 28,800 dekatherms of propane air per day on a 10-day-per-year basis to serve VNG's peaking needs. Construction of the facility is contingent on the final approval by the Virginia State Corporation Commission (VSCC) of the contract between VNG and Pivotal, which is anticipated to be received in the first quarter of 2004.

The following map shows our service areas of distribution operations as well as our LNG and propane facilities:



Energy Investments The properties at energy investments include primarily telecommunications conduit and fiber that is leased or sold to our customers in Atlanta and Phoenix. This includes approximately 58,600 fiber miles and 400 conduit miles of which approximately 9.4% of our dark fiber in Atlanta and 5.8% of our dark fiber in Phoenix has been leased or sold.

Wholesale Services and Corporate The properties used at wholesale services and corporate consist primarily of leased and owned office space in Atlanta and Houston and their contents, including furniture and fixtures. In September 2003, we sold our 34-acre Caroline Street campus in Atlanta, which had been used for operating and administrative functions. As a result of this sale, the majority of our Atlanta-based employees were relocated to Ten Peachtree Place, our new corporate headquarters, pursuant to a new long-term lease arrangement. Ten Peachtree Place is a 20-story building with approximately 250,000 square feet of office space. We currently lease and occupy over 90% of the building.

ITEM 3. 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.

On July 1, 2003, the city of Augusta, Georgia served AGLC with a complaint that was filed in the Superior Court of Richmond County, Georgia. The City of Augusta's allegations include fraud and deceit and damages to realty. The allegations arise from negotiations between the city and AGLC regarding the environmental cleanup obligations connected with AGLC's former manufactured gas plant (MGP) operations in Augusta. The city of Augusta seeks relief in the form of damages (including an amount to be determined by a jury for the alleged fraud and deceit), attorney fees and punitive damages. We believe the claims asserted in this complaint are without merit, and we have remained in active settlement negotiations with the city of Augusta. For more information about MGPs and our environmental cleanup obligations, please see Item 8, "Financial Statements and Supplementary Data" under Note 4, "Regulatory Assets and Liabilities" under "Environmental Response Costs."

In addition, we are 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 litigation in which we are involved will not have a material adverse effect on our consolidated financial statements.

Additional information regarding these proceedings is contained in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under "Results of Operations," and also in Item 8, "Financial Statements and Supplementary Data" under Note 9, "Commitments and Contingencies" under "Litigation."

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

No matters were submitted to a vote of security holders during the fourth quarter of the fiscal year covered by this report.

ITEM 4. (A). EXECUTIVE OFFICERS OF THE REGISTRANT

Set forth below, in accordance with General Instruction G(3) of Form 10-K and Instruction 3 of Item 401(b) of Regulation S-K, are the names, ages and positions of our executive officers along with their business experience during the past five years. Unless otherwise indicated, the information set forth is as of December 31, 2003. The age of each officer listed is as of the date of the filing of this report. Unless otherwise indicated, all of our executive officers have served continuously since the dates indicated. There are no family relationships among the officers.

Name, Age and Position with the Company	Dates Elected or Appointed
Paula G. Rosput, Age 47	
Chairman, President and Chief Executive Officer	February 2002
President and Chief Executive Officer	August 2000 – February 2002
President and Chief Operating Officer of AGLC	September 1998 – November 2000
Kevin P. Madden, Age 51 (1)	
Executive Vice President - Distribution and Pipeline Operations	April 2002
Executive Vice President – Legal, Regulatory and Governmental Strategy	September 2001 – April 2002
Richard T. O'Brien, Age 49 (2)	
Executive Vice President and Chief Financial Officer	April 2001
Paul R. Shlanta, Age 46	
Senior Vice President, General Counsel, Corporate Secretary and Chief Corporate Compliance Officer	September 2002
Senior Vice President, General Counsel and Corporate Secretary	July 2002 – September 2002
Senior Vice President and General Counsel	September 1998 - July 2002

(1) Mr. Madden has previously served as general counsel and chief legal advisor with the FERC from January 2001 – September 2001; as deputy director, Office of Markets, Tariffs and Rates with the FERC from February 2000 – January 2001; and as director, Office of Pipeline Regulations with the FERC from November 1998 – February 2000.

(2) Mr. O'Brien has previously served as vice president of Mirant Corporation from 2000 to 2001 and in various executive positions at PacifiCorp from 1983 to 2000.

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is listed on the New York Stock Exchange under the ticker symbol ATG. At December 31, 2003, there were approximately 44,650 holders of our common stock. The quarterly information concerning stock prices and dividends is contained as follows:

Calendar 2003

	Closing Price of Common Stock		Cash Dividends per
Quarter ended:	High	Low	Common Share
March 31, 2003	$25.18	$22.08	$0.27
June 30, 2003	26.87	23.66	0.28
September 30, 2003	28.42	25.64	0.28
December 31, 2003	29.21	27.34	0.28

Calendar 2002

	Closing Price of Common Stock		Cash Dividends per
Quarter ended:	High	Low	Common Share
March 31, 2002	$23.66	$21.08	$0.27
June 30, 2002	24.21	21.74	0.27
September 30, 2002	23.59	17.94	0.27
December 31, 2002	25.00	20.62	0.27

We pay dividends four times a year: March 1, June 1, September 1 and December 1. We have paid 225 consecutive quarterly dividends beginning in 1948.

ITEM 6. SELECTED FINANCIAL DATA

Dollars and shares in millions, except per share amounts	**Calendar 2003 (1)**	Calendar 2002 (1)	Transition Period (2)	Fiscal 2001 (3)	Fiscal 2000 (3)	Fiscal 1999 (3)
Income statement						
Operating revenues	**$983.7**	$877.2	$203.8	$946.2	$607.8	$1,070.9
Operating expenses						
Cost of gas	**339.4**	268.2	49.1	327.3	111.9	544.7
Operation and maintenance	**282.7**	274.1	68.1	267.2	247.8	268.2
Depreciation and amortization	**91.4**	89.1	23.2	100.0	83.2	78.8
Taxes other than income taxes	**27.8**	29.3	6.0	32.8	26.7	24.4
Total operating expenses	**741.3**	660.7	146.4	727.3	469.6	916.1
Gain on sale of Caroline Street campus	**15.9**	-	-	-	-	-
Operating income	**258.3**	216.5	57.4	218.9	138.2	154.8
Equity in earnings of SouthStar	**45.9**	27.0	4.4	13.7	6.3	(14.2)
Gain on sale of Utilipro	**-**	-	-	10.9	-	-
Gain on propane transaction	**-**	-	-	-	13.1	-
Gain on sale of joint venture interests	**-**	-	-	-	-	35.6
Other income (loss)	**1.9**	3.5	0.5	(7.3)	8.4	(3.6)
Donation to private foundation	**(8.0)**	-	-	-	-	-
Interest expense	**(75.6)**	(86.0)	(23.8)	(97.4)	(57.7)	(59.1)
Earnings before income taxes	**222.5**	161.0	38.5	138.8	108.3	113.5
Income taxes	**86.8**	58.0	13.6	49.9	37.2	39.1
Income before cumulative effect of change in accounting principle	**135.7**	103.0	24.9	88.9	71.1	74.4
Cumulative effect of change in accounting principle, net of $4.8 in income taxes	**(7.8)**	-	-	-	-	-
Net income	**$127.9**	$103.0	$24.9	$88.9	$71.1	$74.4
Common stock data						
Weighted average shares outstanding-basic	**63.1**	56.1	55.3	54.5	55.2	57.4
Weighted average shares outstanding-diluted	**63.7**	56.6	55.6	54.9	55.2	57.4
Earnings per share-basic	**$2.03**	$1.84	$0.45	$1.63	$1.29	$1.30
Earnings per share-diluted	**$2.01**	$1.82	$0.45	$1.62	$1.29	$1.29
Dividends per share	**$1.11**	$1.08	$0.27	$1.08	$1.08	$1.08
Dividend payout ratio	**54.7%**	58.7%	60.0%	66.3%	83.7%	83.1%
Book value per share (4) (5)	**$14.66**	$12.52	$12.41	$12.20	$11.49	$11.58
Market value per share (6)	**$29.10**	$24.30	$23.02	$19.97	$20.08	$16.25
Balance sheet data (4)						
Total assets	**$3,977.8**	$3,742.0	$3,454.3	$3,368.1	$2,587.9	$2,587.6
Long-term liabilities and deferred credits	**645.7**	701.9	670.6	710.8	768.3	806.5
Capitalization						
Long-term debt (excluding current portion)	**730.8**	767.0	797.0	845.0	590.0	610.0
Subsidiaries' obligated mandatorily redeemable preferred securities	**225.3**	227.2	218.0	219.9	74.3	74.3
Common shareholders' equity	**945.3**	710.1	690.1	671.4	620.9	661.5
Total capitalization	**$1,901.4**	$1,704.3	$1,705.1	$1,736.3	$1,285.2	$1,345.8
Financial ratios (4)						
Capitalization						
Long-term debt	**38.4%**	45.0%	46.7%	48.7%	45.9%	45.3%
Subsidiaries' obligated mandatorily redeemable preferred securities	**11.9%**	13.3%	12.8%	12.6%	5.8%	5.5%
Common shareholders' equity	**49.7%**	41.7%	40.5%	38.7%	48.3%	49.2%
Total	**100.0%**	100.0%	100.0%	100.0%	100.0%	100.0%
Return on average common shareholders' equity	**15.5%**	14.7%	14.6%	13.8%	11.1%	11.3%

(1) The 12-month period ending December 31.
(2) The 3-month period ending December 31, 2001.
(3) The 12-month period ending September 30.
(4) As of the last day of the respective fiscal period.
(5) Common shareholders' equity divided by total outstanding common shares.
(6) Closing market price as of the last day of the respective fiscal period.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Summary

The following section is a brief summary of the significant issues addressed in Management's Discussion and Analysis. Investors should read the relevant sections of Management's Discussion and Analysis and the Financial Statements for a complete discussion of the issues summarized below.

Results of Operations

- Our net income increased $24.9 million or 24% over 2002 with basic and diluted earnings per share of $2.03 and $2.01 as compared to $1.84 and $1.82 in 2002 for an increase of $0.19 or 10%.
- The increase in earnings is primarily from increased earnings before interest and taxes (EBIT) of $51.1 million and reduced interest expense of $10.4 million or 12%, offset by an increase in income tax of $28.8 million due to increased earnings before income taxes of $61.5 million and a higher projected effective tax rate for 2003.
- Improved earnings from distribution operations, SouthStar Energy Services LLC (SouthStar) and Sequent Energy Management, L.P. (Sequent) primarily drove the increase in EBIT:
  - **Distribution operations** contributed EBIT of $246.8 million compared to a 2002 EBIT contribution of $224.4 million. Excluding a net $13.5 million pretax gain on the sale of our former corporate headquarters at our Caroline Street campus and a charitable donation, distribution operations' EBIT for 2003 was $233.3 million, a 4% increase over 2002. The increase was primarily due to higher operating margins at Virginia Natural Gas Company, Inc. (VNG) driven by higher customer usage and an increase in the number of connected customers. The increase in Atlanta Gas Light Company's (AGLC) operating margin was from increased pipeline replacement revenues. Total operating expenses, excluding the cost of gas, for 2003 were $366.7 million compared to $362.5 million in 2002. The increase in operating expenses reflects higher overhead costs, including an increase in building lease expenses.
  - **Wholesale services** contributed $19.6 million in EBIT for the year compared to $9.1 million in 2002, a 115% increase. The earnings improvement resulted primarily from increased activity related to optimization of transportation and storage assets and increased commodity margins, particularly in the first quarter of 2003 when Sequent sold substantially all its inventory. Sequent's results also were impacted by Emerging Issues Task Force (EITF) 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'" (EITF 02-03), which rescinded EITF 98-10 and resulted in inventory, which was previously recorded on a mark-to-market basis, to be recorded on an accrual basis. This resulted in a change in accounting principle for a cumulative effect of ($7.8) million or ($0.12) basic earnings per common share.
  - **Energy investments** contributed $43.1 million in EBIT in 2003 compared to $23.6 million in 2002, an 83% increase. SouthStar accounted for the majority of the segment's improved results. SouthStar's improvement resulted primarily from higher operating margins and reduced bad debt and operating expenses, as well as our increased ownership percentage (from 50% to 70%) in the joint venture. Results at SouthStar also reflect the settlement of the disproportionate sharing of earnings with Piedmont Natural Gas Company (Piedmont) in the fourth quarter. The agreement resulted in our recognition of an additional $5.9 million of equity earnings for the 12 months ended December 31, 2003, and resolves all outstanding issues related to disproportionate sharing between the two partners in SouthStar.
  - We closed on the sale of our Caroline Street campus for net proceeds of $22.7 million, resulting in a gain before income taxes of $15.9 million. We contributed $8.0 million of these proceeds to the AGL Resources Private Foundation, Inc., a nonprofit foundation that makes charitable contributions to qualified tax-exempt organizations. This gain net of the donation increased our basic earnings per share from 2002 by an additional $0.08. Excluding the gain, our basic earnings per share for 2003 was $1.95, an increase of $0.11 or 6% over 2002. The gain before income taxes of $15.9 million was recorded as operating income (loss) in two of our segments. A gain of $21.5 million on the sale of the land was recorded in distribution operations, and a write-off of $5.6 million on the buildings and their contents was recorded in our corporate segment.
  - Our operating cash flow in 2003 was $122.1 million, a decrease of $163.4 million from 2002. This decrease was primarily the result of increased spending for injection of natural gas inventories of approximately 11 billion cubic feet (Bcf). The weighted average cost of our inventory was approximately 30% higher than last year. In addition, we made $21.5 million in pension contributions in 2003 as a result of our continued efforts to fully fund our pension liability. The increased spending on inventories and pension funding was partially offset by increased net income of $24.9 million and cash received from SouthStar of $40.0 million.

Liquidity and Capital Resources

- We ended 2003 with a stronger balance sheet, as measured by debt-to-total capitalization and improved liquidity, as measured by cash and availability under our Credit Facility. Primarily through a $136.7 million equity offering of 6.4 million shares and adding $127.9 million of earnings, we increased common equity from $710.1 million at December 31, 2002 to $945.3 million at December 31, 2003.
- We also reduced total debt outstanding from $1,412.8 million at December 31, 2002 to $1,339.5 million at December 31, 2003. As a result, our debt to capitalization ratio decreased from 66.5% at December 31, 2002 to 58.6% at December 31, 2003. Liquidity improved from $252.5 million at December 31, 2002 to $516.5 million at December 31, 2003. Our balance sheet and cash flow improvements enabled us to raise our shareholder dividend. We now pay an indicated annualized dividend of $1.12 per share, a 4% increase over the previous $1.08 per share.
- We currently have an active shelf registration statement for up to $750 million of various capital securities, with remaining capacity of approximately $383 million. On September 23, 2003, we filed a second shelf registration with the Securities and Exchange Commission (SEC) for authority to increase our capacity to $1.0 billion of various capital securities.

Other Activities

- At the beginning of 2003, we announced our purchase of Dynegy Inc.'s (Dynegy's) 20% ownership interest in SouthStar for $20 million. This increase in ownership provided an additional $8.0 million of other income in 2003.
- We formed Pivotal Energy Development (Pivotal) to identify opportunities to extend our natural gas delivery capabilities while improving system reliability. Two such opportunities have been identified to date: a propane-air plant in Virginia, which is currently in the regulatory approval and permitting stages; and a pipeline project between Atlanta and Macon, Georgia to enhance access to a liquefied natural gas (LNG) facility we have there. The construction phase of the Macon project is planned for 2005, pending redeployment of certain existing interstate pipeline infrastructure.

Results of Operations

Our management evaluates segment financial performance based on EBIT, which includes the effects of corporate expense allocations. 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. We evaluate each of these items on a consolidated level. We believe EBIT is a useful measurement of our performance because it provides information that can be used to evaluate the effectiveness of our businesses from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which is directly relevant to the efficiency of those operations.

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, 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. We believe operating margin is a better indicator than revenues of the top line contribution resulting from customer growth, since cost of gas is generally passed directly to our customers.

You should not consider operating margin or EBIT an alternative to, or a more meaningful indicator of our operating performance than, operating income or net income as determined in accordance with accounting principles generally accepted in the United States of America (GAAP). In addition, our operating margin or EBIT may not be comparable to a similarly titled measure of another company. The following is a reconciliation of our operating margin to operating income and a reconciliation of EBIT to earnings before income taxes and net income, on a consolidated basis for 2003, 2002 and fiscal 2001.

We changed our year end from September 30 to December 31, effective October 1, 2001. Results of operations discussions for the transition period (the three months ending December 31, 2001) are included separately in this Annual Report.

In millions, except per share amounts	**Calendar 2003**	**Calendar 2002**	**Fiscal 2001**	**2003 vs. 2002**	**2002 vs. 2001**
Operating revenues	**$983.7**	$877.2	$946.2	$106.5	($69.0)
Cost of gas	**339.4**	268.2	327.3	71.2	(59.1)
Operating margin	**644.3**	609.0	618.9	35.3	(9.9)
Operating expenses					
Operation and maintenance	**282.7**	274.1	267.2	8.6	6.9
Depreciation and amortization	**91.4**	89.1	100.0	2.3	(10.9)
Taxes other than income taxes	**27.8**	29.3	32.8	(1.5)	(3.5)
Total operating expenses	**401.9**	392.5	400.0	9.4	(7.5)
Gain on sale of Caroline Street campus	**15.9**	-	-	15.9	-
Operating income	**258.3**	216.5	218.9	41.8	(2.4)
Other income	**39.8**	30.5	17.3	9.3	13.2
EBIT	**298.1**	247.0	236.2	51.1	10.8
Interest expense	**75.6**	86.0	97.4	(10.4)	(11.4)
Earnings before income taxes	**222.5**	161.0	138.8	61.5	22.2
Income taxes	**86.8**	58.0	49.9	28.8	8.1
Income before cumulative effect of change in accounting principle	**135.7**	103.0	88.9	32.7	14.1
Cumulative effect of change in accounting principle	**(7.8)**	-	-	(7.8)	-
Net income	**$127.9**	$103.0	$88.9	$24.9	$14.1
Basic earnings per common share					
Income before cumulative effect of change in accounting principle	**$2.15**	$1.84	$1.63	$0.31	$0.21
Cumulative effect of change in accounting principle	**(0.12)**	-	-	(0.12)	-
Basic earnings per common share	**$2.03**	$1.84	$1.63	$0.19	$0.21
Diluted earnings per common share					
Income before cumulative effect of change in accounting principle	**$2.13**	$1.82	$1.62	$0.31	$0.20
Cumulative effect of change in accounting principle	**(0.12)**	-	-	(0.12)	-
Diluted earnings per common share	**$2.01**	$1.82	$1.62	$0.19	$0.20
Weighted average number of common shares outstanding					
Basic	**63.1**	56.1	54.5	7.0	1.6
Diluted	**63.7**	56.6	54.9	7.1	1.7

2003 compared to 2002 Net income increased $24.9 million from 2002, reflecting higher earnings at each operating segment. EBIT from distribution operations (excluding the net gain on the sale of the Caroline Street campus of $13.5 million, discussed below) increased 4% ($233.3 million vs. $224.4 million) due to higher operating margins, an increase in the number of connected customers and increased pipeline replacement revenue in 2003. Wholesale services contributed $19.6 million in EBIT compared to $9.1 million in 2002. The earnings improvement resulted primarily from Sequent's optimization of various transportation and storage assets and increased physical volumes sold as well as increased margins driven by favorable pricing and market volatility, particularly in the first quarter of 2003.

Energy investments contributed $43.1 million in EBIT compared to $23.6 million in 2002. SouthStar accounted for the majority of the increase, and its results were driven primarily by higher operating margins, reduced bad debt expense, our expanded ownership interest in the business and the resolution of the disproportionate sharing issue with Piedmont. Our corporate segment's expenses decreased primarily as a result of favorable interest expense and lower average debt balances.

The following table shows the impact of the sale of our Caroline Street campus and the related donation to the private foundation on our distribution operations and corporate segments:

In millions	**Distribution Operations**	**Corporate**	**Consolidated**
Gain (loss) on sale of Caroline Street campus	$21.5	($5.6)	$15.9
Donation to private foundation	(8.0)	-	(8.0)
EBIT impact	13.5	(5.6)	7.9
Income taxes			(3.1)
Net income impact			$4.8

2002 compared to fiscal 2001 Net income for 2002 increased $14.1 million from fiscal 2001, reflecting continued operational efficiencies in distribution operations, greater contributions from wholesale services due to significant price volatility, greater contributions from energy investments due to improved business operations and lower interest expense, partially offset by the gain on the sale of Utilipro Inc. (Utilipro) in 2001.

EBIT by Segment

Distribution operations contributed approximately 80% of our consolidated EBIT in 2003, down from approximately 90% in 2002 and 2001. The decrease was a result of significantly higher EBIT from both wholesale services and energy investments. The following table summarizes EBIT for each of our business segments:

In millions	**Calendar 2003**	**Calendar 2002**	**Fiscal 2001**	**2003 vs. 2002**	**2002 vs. 2001**
Distribution operations	$246.8	$224.4	$213.2	$22.4	$11.2
Wholesale services	19.6	9.1	3.1	10.5	6.0
Energy investments	43.1	23.6	21.3	19.5	2.3
Corporate	(11.4)	(10.1)	(1.4)	(1.3)	(8.7)
Consolidated EBIT	$298.1	$247.0	$236.2	$51.1	$10.8

Income Taxes

Dollars in millions	**Calendar 2003**	**Calendar 2002**	**Fiscal 2001**	**2003 vs. 2002**	**2002 vs. 2001**
Earnings before income taxes	$222.5	$161.0	$138.8	$61.5	$22.2
Income tax expense	86.8	58.0	49.9	28.8	8.1
Effective tax rate	39.0%	36.0%	36.0%	3.0%	-

2003 compared to 2002 The increase in income tax expense of $28.8 million for 2003 compared to 2002 was primarily due to the increase in earnings before income taxes of $61.5 million and an increase in our effective tax rate from 36.0% in 2002 to 39.0% in 2003. The increase in the effective tax rate for 2003 was primarily due to higher projected state income taxes resulting from a change in Georgia law governing the methodology by which Georgia companies must compute their tax liabilities and to the accrual of deferred tax liabilities related to temporary differences between the book and tax basis of some of our assets.

2002 compared to fiscal 2001 The increase in income tax expense of $8.1 million in 2002 as compared to fiscal 2001 was due to the increase in earnings before income taxes of $22.2 million while the effective tax rate was unchanged.

Interest Expense

Dollars in millions	**Calendar 2003**	**Calendar 2002**	**Fiscal 2001**	**2003 vs. 2002**	**2002 vs. 2001**
Total interest expense	$75.6	$86.0	$97.4	($10.4)	($11.4)
Average debt outstanding (1)	1,255.3	1,411.9	1,376.1	(156.6)	35.8
Average rate	6.0%	6.1%	7.1%	(0.1%)	(1.0%)

(1) Daily average of all outstanding debt including our Trust Preferred Securities.

2003 compared to 2002 The decrease in interest expense of $10.4 million for 2003 as compared to 2002 was a result of lower average debt balances due primarily to the proceeds generated from our equity offering; repayment of Medium-Term notes, which had higher rates than our bond issuance in July; the benefits of our interest rate swaps; and lower interest rates on commercial paper borrowings.

2002 compared to fiscal 2001 The decrease in interest expense of $11.4 million for 2002 as compared to fiscal 2001 was a result of lower interest rates on commercial paper and the effect of favorable fixed to floating interest rate swaps, offset by slightly higher average debt balances due to increases in working capital needs.

Distribution Operations

Distribution operations includes the results of operations and financial condition of our three natural gas local distribution utility companies: AGLC, VNG and Chattanooga Gas Company (CGC). Distribution operations' revenues contributed 95.1% of our consolidated revenues for 2003, 97.1% for 2002, 96.8% for the transition period and 97.2% for fiscal 2001. Each utility operates subject to regulations provided by the state regulatory agencies in its service territories.

- **AGLC** is a natural gas local distribution utility with distribution systems and related facilities throughout Georgia. AGLC has approximately 6 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 Georgia Public Service Commission (GPSC) to sell retail natural gas in Georgia --at rates and on terms approved by the GPSC.

  Performance-Based Rates AGLC operates under a three-year performance-based rate (PBR) plan that became effective May 1, 2002, with an allowed return on equity of 11%. The PBR plan also establishes an earnings band based on a return on equity of 10% to 12%, with three-quarters of any earnings above a 12% return on equity shared with Georgia customers and one-quarter retained by AGLC.

  In the last year of the PBR plan (May 2004 – April 2005), the GPSC staff and AGLC will review the operation of the plan and review AGLC's revenue requirement to determine whether base rates should be reset upon the initial plan's expiration. The GPSC will then determine whether the plan should be discontinued, extended or otherwise modified. As part of any hearing procedure, AGLC will file a cost-of-service study in accordance with the GPSC's minimum filing requirements as well as supporting testimony. AGLC plans to file the required cost-of-service study in 2004, the precise timing of which is subject to discussions with the GPSC staff.

  Straight-Fixed-Variable Rates AGLC's revenue is recognized under a straight-fixed-variable rate design, whereby AGLC charges rates to its customers based primarily on a fixed charge. This minimizes the seasonality of both revenues and expenses since the fixed charge is not volumetric and therefore not directly weather dependent. Weather indirectly influences the number of customers that have active accounts during the heating season, and this has a seasonal impact on AGLC's revenues, since generally more customers will be connected in periods of colder weather than in periods of warmer weather.

- **VNG** is a natural gas local distribution utility with distribution systems and related facilities serving the region of 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.

  Weather normalization adjustment On September 27, 2002, the Virginia State Corporation Commission (VSCC) approved a weather normalization adjustment (WNA) program as a two-year experiment involving the use of special rates. The WNA program's purpose is to reduce the effect of weather on customer bills by reducing bills when winter weather is colder than normal and increasing bills when winter weather is warmer than normal. Under the terms of the program, if VNG requests to continue the WNA program after the two-year experiment, it is required to file a fully adjusted cost-of-service study along with the same schedules as would be required for a general rate case. It is possible the VSCC may require a general rate case prior to extending the WNA program. VNG plans to request an extension of the WNA program in 2004.

- **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 base rates charged by CGC is a WNA factor that allows for revenue to be recognized based on a weather normalization factor derived from average temperatures over a 30-year period, which offsets the impact of unusually cold or warm weather on its operating income.

  On January 26, 2004, CGC filed a request for a total rate increase of $4.5 million with the Tennessee Regulatory Authority (TRA), as rates have not increased since 1995. If approved, new rates would be effective March 1, 2004, subject to a TRA suspension for hearing. The rate plan was filed to cover CGC's rising cost of providing natural gas to its customers.

Pivotal Energy Development In 2003, we announced the formation of Pivotal to coordinate, among our related companies, the development, construction or acquisition of assets in the Southeast and Mid-Atlantic regions to extend our natural gas capabilities and improve system reliability while enhancing service to our customers in those areas.

- **Virginia** In 2004, Pivotal intends to complete the construction of a propane facility in the VNG service territory. A filing with the VSCC was made in November 2003 seeking approval for an affiliate contract between Pivotal and VNG. Under this proposed contract, Pivotal would provide VNG with 28,800 dekatherms of propane air per day on a 10-day-per-year basis to serve its peaking needs. Construction of the facility by Pivotal is contingent upon the VSCC's approval of the contract between Pivotal and VNG, and we expect its decision during the first quarter of 2004.
- **Georgia** Pivotal is currently evaluating a pipeline project between Atlanta and Macon to enhance access to our LNG facility and lower the cost of gas to our customers. The construction phase of the Macon project is planned for 2005, pending redeployment of certain existing interstate pipeline infrastructure.

Gas Supply Gas supply or capacity planning is conducted for each of our regulated jurisdictions. The basic premise of a capacity plan is to evaluate the costs of alternative asset arrays meeting firm customer demand for natural gas under varying weather conditions that exist in our service territories. On an annual basis the array of assets for each utility must have adequate interstate transportation, underground storage and LNG capacity to meet firm customer demand if the weather is colder than normal, and must be flexible enough to adjust for firm customer demand in a winter that is warmer than normal.

Rates and Regulation The GPSC regulates AGLC; the VSCC regulates VNG; and the 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, pay preferred dividends 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 filing. The following table depicts the currently authorized and estimated rates of return for AGLC, VNG and CGC:

	Authorized Return on Rate Base	Authorized Return on Equity	Estimated 2003 Jurisdictional Return on Equity
AGLC	9.16%	10.0 – 12.0%	11.19%
VNG	9.24%	10.0 – 11.4%	11.15%
CGC	9.08%	11.06%	8.05%

State Activity Since 1998, a number of federal and state proceedings have addressed the role of AGLC to administer and assign interstate assets to Marketers pursuant to the provisions of the Natural Gas Competition and Deregulation Act of Georgia. Most recently, AGLC entered into a stipulation with the GPSC staff, industrial customers, the Governor's Office of Consumer Affairs and all but one of the Marketers using its systems regarding the assignment of its interstate capacity assets. A hearing to approve the stipulation was held, and on July 24, 2003, the GPSC unanimously approved the stipulation. Under the approved terms, AGLC is authorized to offer two additional sales services pursuant to GPSC-approved tariffs, and acquire and continue managing the interstate transportation and storage contracts that underlie the sales services provided to Marketers on its distribution system under GPSC-approved tariffs.

Federal Activity The Pipeline Safety Improvement Act of 2002, enacted on December 17, 2002, required the Office of Pipeline Safety (OPS) to establish new regulations for the inspection of transmission pipelines by December 2003. The OPS issued its final rules in December 2003. The OPS rules will require our three utility subsidiaries to inspect and take remedial action on approximately 350 miles of our large-diameter pipelines with an initial estimated cost over a 10-year period of $22 million in maintenance expense. We believe that since the efforts that require these expenditures are federally mandated the costs will be recoverable from customers.

On January 14, 2004, VNG filed a complaint with the Federal Energy Regulatory Commission (FERC) against Columbia Gas Transmission (Columbia), a subsidiary of NiSource Inc. Among other things, the complaint alleges that during last winter's heating season, beginning in January 2003, VNG experienced a number of critical service problems with Columbia that interrupted deliveries of natural gas to some industrial customers and increased prices paid by VNG's customers. VNG is seeking approximately $37 million in damages, the majority of which would be distributed to VNG's customers.

Competition Our distribution operations businesses face competition based on our customers' preferences for natural gas compared to other energy products and the comparative prices of those products. Our principal competition relates to 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 versus electric heating. Also, price volatility in the wholesale natural gas commodity market has resulted in increases in the cost of natural gas billed to customers.

Competition for space heating and general household and small commercial energy needs generally occurs at the initial installation phase when the customer/builder typically makes decisions as to which types of equipment to install and operate. The customer will generally continue to use the chosen energy source for the life of the equipment. We believe that our consumers' continuing preference for natural gas allows us to maintain a strong market presence. However, our customers' demand for natural gas and the level of business of 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
- weather

Customer profile Distribution operations primarily serves residential customers, as shown in the following table:

	AGLC	VNG	CGC
Residential	91%	92%	86%
Commercial and industrial	9	8	14
Total	100%	100%	100%

In 2003, our net customer growth was approximately 1%. While we experienced positive net growth, it has been limited due to the number of customers who choose to leave our systems. We expect our net customer growth to improve in the future through our efforts in

- New business – Add residential customers with three or more appliances (burner tips), multifamily complexes, and we continue to seek high-value commercial customers that use natural gas for purposes other than space heating.
- Retention – Partner with numerous entities, including appliance retailers, HVAC dealers, plumbers, realtors and natural gas marketers to market the benefits of gas appliances and to identify early in the process those customers who may opt to leave our franchise or convert to alternative fuels.

Results of Operations The results of operations for distribution operations are as follows:

In millions	Calendar 2003	Calendar 2002	Fiscal 2001	2003 vs. 2002	2002 vs. 2001
Operating revenues	$935.9	$852.4	$919.6	$83.5	($67.2)
Cost of gas	337.3	267.4	321.9	69.9	(54.5)
Operating margin	598.6	585.0	597.7	13.6	(12.7)
Operation and maintenance expenses	261.3	255.3	268.0	6.0	(12.7)
Depreciation and amortization	80.9	82.0	90.4	(1.1)	(8.4)
Taxes other than income	24.5	25.2	28.5	(0.7)	(3.3)
Total operating expenses	366.7	362.5	386.9	4.2	(24.4)
Gain on sale of Caroline Street campus	21.5	-	-	21.5	-
Operating income	253.4	222.5	210.8	30.9	11.7
Donation to private foundation	(8.0)	-	-	(8.0)	-
Other income	1.4	1.9	2.4	(0.5)	(0.5)
Total other (loss) income	(6.6)	1.9	2.4	(8.5)	(0.5)
EBIT	$246.8	$224.4	$213.2	$22.4	$11.2
Metrics					
Average end-use customers (in thousands)	1,838	1,824	1,829	0.8%	(0.3%)
Operation and maintenance expenses per customer	$142	$140	$147	1.4	(4.8)
EBIT per customer (1)	$127	$123	$117	3.3	5.1
Customers per employee	948	918	886	3.3	3.6
Throughput (in millions of dekatherms)					
Firm	190	182	206	4.4	(11.7)
Interruptible	109	124	117	(12.1)	6.0
Total	299	306	323	(2.3)	(5.3)
Heating degree days (2):					
Georgia	2,654	2,812	3,072	(5.6)	(8.4)
Virginia	3,264	3,030	3,659	7.7	(17.1)
Tennessee	3,168	3,052	3,435	3.8	(11.1)

(1) 2003 EBIT per customer excludes the gain on the sale of our Caroline Street campus.

(2) 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.

2003 compared to 2002 EBIT increased $22.4 million for 2003 as compared to 2002, primarily as a result of the gain of $21.5 million on the sale of the land from our Caroline Street campus, offset by the $8.0 million donation to AGL Resources Private Foundation, Inc. Excluding the gain and donation, EBIT increased $8.9 million from improved operations as a result of increased operating margin, partially offset by increased operating expenses.

Operating margin increased $13.6 million from 2002. This was primarily from an increased number of customers and a higher usage per degree day, of which VNG contributed approximately $12.0 million. Pipeline replacement program (PRP) rider revenues increased $2.3 million, resulting from recovery of prior-year program expenses. Carrying costs charged to Marketers for gas stored underground also contributed $0.7 million due to higher storage volumes. Offsetting the increases was a reduction in AGLC's rates as compared to prior year of $3.3 million for the first four months of 2003 due to the PBR settlement agreement with the GPSC effective May 1, 2002. CGC's operating margin for 2003 was not materially different from 2002.

Operating expenses increased $4.2 million from 2002 due primarily to a $2.0 million increase in corporate allocated costs related to an increase in corporate building lease costs and higher general business insurance premiums. Bad debt expenses increased $2.2 million, primarily as a result of colder-than-normal weather and higher natural gas prices. Additional increases in operating expenses were attributed to a $1.2 million VNG regulatory asset write-off in 2003. These increases in operating expenses were partially offset by a $1.1 million decrease in depreciation expenses due to lower depreciation rates at AGLC for the first four months of 2003 as a result of the PBR settlement agreement with the GPSC.

2002 compared to fiscal 2001 The increase in EBIT of $11.2 million for 2002 compared to fiscal 2001 was primarily due to decreases in operating expenses of $24.4 million, partially offset by decreases in operating margin of $12.7 million.

Operating margin decreased $12.7 million primarily due to the following:

- VNG's operating margin decreased $11.3 million, resulting from the impact of warmer-than-normal winter weather of $12.4 million, partially offset by a $1.1 million increase in customers and the positive impact of an experimental WNA program that went into effect for the billing cycle beginning November 2002.
- CGC's operating margin decreased $1.2 million, primarily due to lower use per customer.
- AGLC's operating margin decreased $0.1 million, primarily due to a $6.7 million decrease in AGLC's rates as a result of the PBR settlement with the GPSC, and a decrease of $4.3 million as a result of a decline in the number of customers due to fewer end-use customers connecting to our system. Additional decreases to AGLC margin were a $2.7 million one-time adjustment in 2001 to cost of gas as a result of inventory cost for natural gas stored underground. These decreases were offset by an $11.0 million increase in AGLC's PRP rider revenues resulting from recovery of prior-year program expenses, and an increase in carrying costs charged to Marketers for gas stored underground that contributed an additional $3.0 million.

Operating expenses decreased $24.4 million primarily due to the following:

- Operation and maintenance expenses decreased $12.7 million related to reductions in payroll and contract costs as a result of implementing cost efficiencies.
- Bad debt expenses decreased $6.0 million as a result of higher-than-normal bad debt expense in fiscal 2001 due to colder-than-normal weather and higher-than-normal gas prices, resulting in higher customer bills during the 2001 heating season.
- Goodwill amortization decreased $5.2 million from 2001 as a result of the adoption of Statement of Financial Accounting Standards (SFAS) No. 142, "Goodwill and Other Intangible Assets" (SFAS 142), effective October 1, 2001.
- Depreciation expense decreased $3.0 million in 2002 as compared to fiscal 2001, due to a decrease of $5.6 million caused by a decline in average depreciation rates (from 3.0% to 2.6%) as a result of AGLC's PBR settlement with the GPSC effective May 1, 2002, partially offset by an increase in depreciation expenses of $3.3 million due to higher property, plant and equipment balances.

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.

Asset management transactions Our asset management customers include our affiliated local distribution companies (LDCs), nonaffiliated utilities, municipal customers and industrial customers. These customers must contract for transportation and storage services to meet their peak-day demands, and typically contract for these services on a 365-day basis even though they may only need these services to meet their peak demands for a much shorter period. We enter into agreements with these customers, either through contract assignment or agency arrangement, whereby we use their rights to transportation and storage services during off-peak periods. We capture margin by optimizing the purchase, transportation, storage and sale of natural gas, and typically either share profits with customers or pay a fee for using utility assets.

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

- 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.
- 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.
- In June 2003, CGC's tariff was amended effective January 1, 2003 to require all 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. From May 2001 to December 2002, Sequent operated under a bailment agreement and annually paid $0.3 million to manage CGC's assets.

Transportation and storage transactions In our wholesale marketing and risk management business, we also contract for our own transportation and storage services. We participate in transactions to manage the natural gas commodity and transportation costs that result in the lowest cost to serve our various markets. We then seek to optimize this process on a daily basis as market conditions change by evaluating all the natural gas supplies, transportation and markets to which we have access and seek out the least-cost alternatives to serve our various markets. This enables us to capture geographic pricing differences across these various markets as delivered gas prices change.

In a similar manner, we participate in natural gas storage transactions where we seek to identify pricing differences that occur over time as prices for future delivery periods at many locations are readily available. We capture margin by locking in the economic price differential between purchasing natural gas at the lowest future price and, in a related transaction, selling that gas at the highest future price, all within the constraints of our contracts. Through the use of transportation and storage services, we are able to capture margin through the arbitrage of geographical pricing differences and by recognizing pricing differences that occur over time.

Producer services Our producer services business primarily focuses on aggregating natural gas supply from various small and medium-sized producers located throughout the natural gas production areas of the United States. We provide the producers certain logistical and risk management services that offer them attractive options to move their supply into the pipeline grid. Aggregating volumes of natural gas from these producers allows us to provide markets to producers who seek a reliable outlet for their natural gas production.

Peaking services Wholesale services generates operating margin through the sale of peaking services, which includes receiving a fee from customers that guarantees that those customers will receive gas under peak conditions. The primary customer for these peaking services has historically been AGLC. Under these peaking services, wholesale services recorded gross revenues of $10.6 million in 2003, $11.4 million in 2002 and zero in fiscal 2001. All our peaking arrangements expire March 31, 2004. Wholesale services also incurs costs to support our obligations under these agreements, which will be reduced in whole or in part as the matching obligations expire. 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 aggressively enter into new peaking transactions as well as work toward extending those that are set to expire.

Competition Sequent, although regionally focused in the eastern half of the United States, competes for natural gas suppliers and customers with national and regional full-service energy providers, energy merchants, several large commercial and investment banks and natural gas producers. Due to the events in our industry in the last four years, the amount of competition has been significantly reduced. Our success is based on our ability to aggregate competitively priced commodities and services from our transportation and storage capacity and tailor our services to the customers' needs. We believe that we will continue to provide the basic services many customers are seeking, and we should benefit from the reduction in the number of competitors.

Business Expansion Sequent has been focusing on expanding its business, both geographically and through added emphasis on the origination of new asset management transactions and growing the producer services businesses. Throughout 2003 we added personnel to focus specifically on these opportunities. Our business territory now extends from Texas to Chicago and all other areas of the United States east of the Mississippi River. In the fourth quarter of 2003, we executed four new nonaffiliated asset management transactions and have increased our producer services volumes. This expansion, as well as our other business growth, has increased Sequent's fixed cost commitments in the form of firm capacity charges for transportation and storage contracts, and lengthened the average tenure of our portfolio to seven months. At December 31, 2003, Sequent's longest-dated contract in its portfolio was nine years, with contract terms ranging from one day to nine years. Sequent's firm capacity commitments currently are

- $9.4 million in 2004
- $2.6 million in 2005
- $1.8 million in 2006

Seasonality Fixed cost commitments are generally incurred evenly over the year, while margins generated through the use of these assets are generally greatest in the winter heating season and in the summer due to peak usage by power generators for meeting air conditioning load. This increases the seasonality of our business, generally resulting in expected higher margins in the first and fourth quarters.

Business Outlook Continued growth of the nonaffiliated asset management and producer services business lines will be critical to Sequent's success in 2004. Given the continued exit of Marketers due to business repositioning and credit limitations, Sequent should benefit through increased market share. Additionally, although we manage our business with limited open positions and value at risk (VaR), the rescission of EITF 98-10 and our adoption of EITF 02-03 could increase earnings volatility in our reported results, as more fully discussed below under "Energy Marketing and Risk Management activities."

Energy Marketing and Risk Management Activities During 2003, 2002 and fiscal 2001, we accounted for derivative transactions in connection with our energy marketing activities on a mark-to-market basis in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133), and during 2002 and 2001 we accounted for nonderivative energy and energy-related activities in accordance with EITF 98-10.

Under these methods, we recorded energy commodity contracts (including both physical transactions and financial instruments) at fair value, with unrealized gains or losses from changes in fair value reflected in our earnings in the period of change. We also recorded energy-trading contracts, as defined under EITF 98-10, on a mark-to-market basis for transactions executed on or before October 25, 2002. Energy-trading contracts entered into after October 25, 2002 were recorded on an accrual basis as required under EITF 02-03's rescission of EITF 98-10, unless they were derivatives that must be recorded at fair value under SFAS 133.

Effective January 1, 2003, we adopted EITF 02-03, which rescinded EITF 98-10, and reached two general conclusions:

- Contracts that do not meet the definition of a derivative under SFAS 133 should not be marked to fair market value.
- Revenues should be shown in the income statement net of costs associated with trading activities, whether or not the trades are physically settled.

Our adoption of EITF 02-03 had the following impact:

- We recorded an adjustment to the carrying value of our nonderivative trading instruments (principally our storage capacity contracts) to zero, and now account for them using the accrual method of accounting.
- We recorded an adjustment to the value of our natural gas inventories used in wholesale services to the lower of average cost or market; they were previously recorded at fair value. This resulted in the cumulative effect of a change in accounting principle in our statements of consolidated income for the three months ended March 31, 2003 of $12.6 million ($7.8 million net of taxes), which resulted in a decrease of $12.6 million to our energy marketing and risk management assets and a decrease in accumulated deferred income taxes of $4.8 million in our accompanying consolidated balance sheets.
- We reclassified our trading activity on a net basis (revenues net of costs) effective July 1, 2002 as a result of the first consensus of EITF 02-03. This reclassification had no impact on our previously reported net income or shareholders' equity. Revenues for 2002 and fiscal 2001 are shown net of costs associated with trading activities.

Sequent recorded unrealized gains of $0.7 million, excluding the cumulative effect of a change in accounting principle, during 2003, and unrealized gains of $4.1 million in 2002 and $2.9 million in fiscal 2001, 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 2003 and 2002 and provide details of the net fair value of contracts outstanding as of December 31, 2003. Sequent's storage positions are affected by price sensitivity in the New York Mercantile Exchange, Inc. (NYMEX) average price.

In millions	Calendar 2003	Calendar 2002
Net fair value of contracts outstanding at beginning of period	$6.8	$2.9
Cumulative effect of change in accounting principle	(12.6)	-
Net fair value of contracts outstanding at beginning of period, as adjusted	(5.8)	2.9
Contracts realized or otherwise settled during period	1.5	(4.9)
Change in net fair value of contract (losses) gains	(0.8)	8.8
Net fair value of new contracts entered into during period	-	-
Net fair value of contracts outstanding at end of period	($5.1)	$6.8

The sources of our net fair value at December 31, 2003 are as follows:

In millions	Maturity Less than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in Excess of 5 Years	Total Net Fair Value
Prices actively quoted (1)	$5.6	$(1.0)	$-	$-	$4.6
Prices provided by other external sources	(9.8)	0.1	-	-	(9.7)

(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.

We had a net risk management liability at December 31, 2003 of $5.1 million compared to a net risk management asset of $6.8 million at December 31, 2002. We determined the amounts for 2002 relating to gas storage inventory on a mark-to-market basis, which was the appropriate accounting method at that time. We recorded the gas storage inventory in 2003 on an accrual basis, at the lower of average cost or market. Therefore, these amounts are not directly comparable. The fair value of our gas storage inventory position at December 31, 2003 was higher than average cost, but the fair value is not reflected in the financial statements due to the accounting rules now in effect.

At December 31, 2003 the fair value of this inventory was in excess of average cost by approximately $5.3 million. We used a calculation to compare the forward value using market prices at the expected withdrawal period with the cost of inventory included in the balance sheet. Additionally, $1.9 million of this value must be shared under our asset management agreements but would be recorded in accounts payable. This net $3.4 million incremental value would have been reflected in our earnings for the year under mark-to-market accounting.

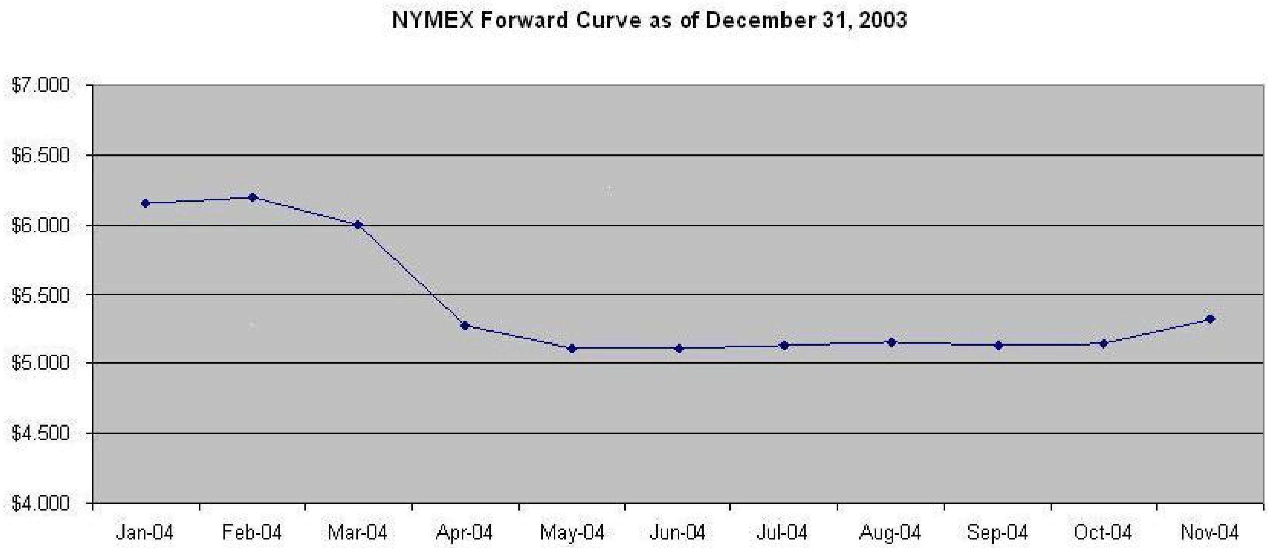
Storage Inventory Outlook The NYMEX forward curve graph reflects the NYMEX natural gas prices as of December 31, 2003, also known as the NYMEX forward curve, through November 2004. These are the prices on December 31, 2003 at which we could buy natural gas at the Henry Hub for delivery in the time period of January through November 2004.

"Open futures NYMEX contracts" represents the volume in contract equivalents of the transactions we executed to economically hedge our storage inventory. As of December 31, 2003, the expected withdrawal schedule of this inventory and its weighted average costs are reflected in the entry "physical withdrawal schedule." Our futures contracts qualify as derivatives under 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 December 31, 2003. This gross margin could change as we adjust our daily injection and withdrawal plans due to changes in market conditions.

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 gas on or borrow gas from the pipeline in one period and reclaim gas from or repay gas to the pipeline in a subsequent period. The economics of these transactions are evaluated and 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 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 gas is repaid. As a result, these transactions qualify as derivatives under SFAS 133 that 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 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 December 31, 2003 that are 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 forward curves at December 31, 2003.



	Jan. 2004 (1)	Feb. 2004	Mar. 2004	Apr. 2004	May 2004	June 2004	July 2004
Open futures NYMEX contracts (short) long	(156)	(218)	(76)	-	-	-	69
Physical withdrawal schedule as of December 31, 2003 (NYMEX contract equivalents)							
Salt dome (WACOG = $4.93)	102	-	-	-	-	-	-
Reservoir (WACOG = $5.68)	54	218	76	-	-	-	(69)
Total	156	218	76	-	-	-	(69)
Expected gross margin, after regulatory sharing (2) *(In millions)*							
Reservoir	$0.4	$1.4	$0.4	$-	$-	$-	$-
Salt dome	1.2	-	-	-	-	-	-

(1) January futures expired on December 29, 2003; however, they are included herein as they coincide with the January storage withdrawals.

(2) As a result of our positions, a $0.10 parallel change in future NYMEX prices would impact our EBIT by $0.3 million at December 31, 2003. A $0.10 change in the price of gas realized on the withdrawal of physical inventory would impact our EBIT by $0.3 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 lower of average cost or market.

In millions	Jan. 2004	Feb. 2004	Mar. 2004	Apr. 2004	May 2004	June 2004	July 2004	Aug. 2004	Nov. 2004
Park and (loan) volumes	(.28)	(.10)	(1.12)	(.35)	.40	.20	.50	.15	.60
Expected gross margin from park and loans	$0.1	$-	$0.4	$-	$-	$-	$-	$-	$-

Results of Operations The results of operations for wholesale services are as follows:

In millions	Calendar 2003	Calendar 2002	Fiscal 2001	2003 vs. 2002	2002 vs. 2001
Operating revenues	$41.2	$23.0	$11.6	$18.2	$11.4
Cost of sales	1.4	0.3	0.2	1.1	0.1
Operating margin	39.8	22.7	11.4	17.1	11.3
Operation and maintenance expenses	19.4	13.2	6.1	6.2	7.1
Depreciation and amortization	0.1	-	-	0.1	-
Taxes other than income	0.4	0.4	-	-	0.4
Total operating expenses	19.9	13.6	6.1	6.3	7.5
Operating income	19.9	9.1	5.3	10.8	3.8
Other loss	(0.3)	-	(2.2)	(0.3)	2.2
EBIT	$19.6	$9.1	$3.1	$10.5	$6.0
Metrics					
Physical sales volumes (Bcf/day)	1.75	1.39	0.1	26%	1,290%

2003 compared to 2002 EBIT increased $10.5 million from 2002 primarily due to a $17.1 million increase in operating margin, offset by an increase of $6.3 million in operating expenses.

Operating margin increased $17.1 million due primarily to Sequent's optimization of various transportation and storage assets, mainly in the first quarter when natural gas prices were highly volatile. In the first quarter, Sequent sold substantially all its inventory that was previously recorded on a mark-to-market basis under the now-rescinded EITF 98-10. This resulted in $12.6 million in realized income, offset by amounts shared with our affiliated LDCs for transactions that were recorded on a mark-to-market basis in prior periods. The increase in operating margin was partly offset by lower natural gas volatility created by unseasonably cool temperatures in the Southeast, Midwest and Upper Mid-Atlantic during the summer of 2003. As compared to the summer of 2002, when volatility was higher as a result of two hurricanes in the Gulf of Mexico and warmer-than-normal temperatures in the Northeast.

Operating expenses increased by $6.3 million, primarily due to a $3.1 million increase in corporate costs and a $3.2 million increase primarily due to personnel and outside consulting costs incurred while growing the business.

Sequent's physical sales volumes for 2003 increased 26% to 1.75 Bcf/day as compared to 2002. This increase was partially attributable to Sequent's successful efforts to gain additional new business in the Midwest and Northeast. Additionally, a number of market factors, including colder temperatures during the winter in market areas served by Sequent and reduced amounts of gas in storage as the winter progressed, resulted in increased volatility in Sequent's markets during the first quarter of 2003 compared to the same period of 2002. The volatility in the second and third quarters returned to seasonal averages and increased slightly above average in the fourth quarter.

2002 compared to fiscal 2001 The increase in EBIT of $6.0 million for 2002 as compared to fiscal 2001 was due to increased operating margin of $11.3 million and a $2.2 million decrease in other loss, offset by a $7.5 million increase in operating expenses.

Operating margin increased $11.3 million, primarily from increased weather volatility from warmer-than-normal weather in the Northeast, two hurricanes during the late summer, colder weather in November and December, and an overall increase in volumes sold. These weather-related events caused interruption in the supply/demand equilibrium between the affected production and market areas, resulting in wide geographical pricing disparities.

Sequent used its access to contracted assets and its expertise in logistics to maximize the profit opportunity by flowing gas on the most economical path available. Additionally, operating margin was positively impacted by peaking services, which were not provided in fiscal 2001. Physical gas sales volumes increased from 0.1 Bcf/day in fiscal 2001 to 1.39 Bcf/day in 2002.

Operating expenses increased $7.5 million, primarily from the addition of personnel to support growth in the business and a full year of operating expenses following Sequent's formation in early 2001. Other loss decreased $2.2 million primarily due to the write-off in fiscal 2001 of our investment in Etowah LNG of $2.6 million, resulting from the termination of the joint venture partnership originally formed in 1998.

Energy Investments

Our energy investments segment includes our investments in SouthStar and US Propane LP (US Propane), the results of operations and financial condition of AGL Networks, LLC (AGL Networks), and Utilipro through the date of its sale in 2001.

- **SouthStar** is a joint venture formed in 1998 by our subsidiary, Georgia Natural Gas Company, Piedmont and Dynegy to market natural gas and related services to retail customers, principally in Georgia. Initially, we owned a 50% interest in SouthStar, Piedmont owned a 30% interest and Dynegy owned the remaining 20% interest.

  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. Upon closing, we owned a noncontrolling 70% financial interest in SouthStar and Piedmont owned the remaining 30%. Our 70% interest is noncontrolling because all significant matters require approval by both owners. We recognize our equity in earnings of SouthStar based upon our ownership interest plus the amount recognized for disproportionate sharing, as discussed below. For all periods prior to February 18, 2003, SouthStar's earnings have been allocated to us based upon our ownership interests in those periods or 50%.

  Competition 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. Based upon its market share, SouthStar is the largest retail marketer of natural gas in Georgia with a monthly year-to-date average of approximately 557,700 customers. This represents a market share of approximately 37.5% as of December 31, 2003, which is relatively consistent with its market share of 38.2% in the prior year.

  Disproportionate sharing SouthStar's operating policy contains provisions for the disproportionate sharing of earnings with our partner in SouthStar, Piedmont, when SouthStar's annual earnings before taxes exceed a certain threshold. The threshold is calculated each year based on a cumulative and annual return on contributed capital. SouthStar's operating policy requires that earnings above the threshold be allocated at various percentages based on actual margin generated in the four defined service areas of the operating policy, and distributed annually to each owner as a mandatory distribution. Disproportionate sharing is only applicable to our original 50% financial interest in SouthStar. No disproportionate sharing of earnings had occurred prior to December 2003 because the owners had not reached an agreement on how disproportionate sharing should be calculated.

  On December 31, 2003, the owners resolved their differences over the interpretation of the provisions in the operating policy that provided for the disproportionate sharing of earnings through an agreement that provides for SouthStar's 2003 earnings to be allocated 80% to us and 20% to Piedmont, less income allocable to Dynegy prior to February 18, 2003. The agreement resulted in our recognition of $5.9 million of equity earnings for disproportionate sharing for the 12 months ended December 31, 2003.

  The agreement also provided for a one-time cash distribution of $40 million to the owners on December 31, 2003, which was allocated $34 million to us and $6 million to Piedmont. The agreement further resolved all issues related to the allocation of earnings for all years prior to 2003 by allocating earnings for such prior years based on the current owners' respective interests for such prior fiscal years.

- **AGL Networks**, our wholly owned subsidiary, is a provider of telecommunications conduit and 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.

  In 2003, AGL Networks determined that it would focus on wholesale telecommunications customers. In particular, these customers would use our network to provide communications services to commercial entities or to create private metropolitan networks. Our primary goals for this business in the next 12 to 15 months are to

  - increase revenues through our sales efforts to achieve break-even or better results by the end of 2004
  - maintain control of capital costs for connecting carriers to the network
  - maintain control of sales and operating expenses

Competition AGL Networks' competitors exist to the extent that they have or will lay conduit and fiber or may install conduit in the future on the same route in the respective metropolitan areas. We believe our footprint in Atlanta is a unique continuous ring and, as such, will be subscribed ahead of most competitors as market conditions support greater use of our product.

- **US Propane** is a joint venture formed in 2000 by us, Atmos Energy Corporation, Piedmont and TECO Energy, Inc. During 2003, 2002 and fiscal 2001, we owned 22.36% of the limited partnership interests in US Propane. US Propane owns all the general partnership interests, directly or indirectly, and approximately 25% of the limited partnership interests in Heritage, a publicly traded marketer of propane.

  On January 20, 2004, we closed on an agreement to sell our general and limited partnership interests in Heritage. The agreement involved our subsidiaries, AGL Propane Services Inc. and AGL Energy Corporation, and the three other nonaffiliated utility partners. The aggregate transaction was valued at $130 million. Upon closing, we received $29 million for the sale of our interests. We do not expect to recognize a material gain or loss on the transaction in 2004.

Results of operations The results of operations for energy investments are as follows:

In millions	**Calendar 2003**	**Calendar 2002**	**Fiscal 2001**	**2003 vs. 2002**	**2002 vs. 2001**
Operating revenues	$6.5	$2.0	$9.2	$4.5	($7.2)
Cost of sales	0.7	0.5	1.2	0.2	(0.7)
Operating margin	5.8	1.5	8.0	4.3	(6.5)
Operation and maintenance expenses	9.3	7.5	11.5	1.8	(4.0)
Depreciation and amortization	0.9	0.3	0.9	0.6	(0.6)
Taxes other than income	0.5	0.2	0.5	0.3	(0.3)
Total operating expenses	10.7	8.0	12.9	2.7	(4.9)
Operating loss	(4.9)	(6.5)	(4.9)	1.6	(1.6)
Equity earnings from SouthStar	45.9	27.0	13.7	18.9	13.3
Gain on the sale of Utilipro	-	-	10.9	-	(10.9)
Other income	2.1	3.1	1.6	(1.0)	1.5
Total other income	48.0	30.1	26.2	17.9	3.9
EBIT	$43.1	$23.6	$21.3	$19.5	$2.3
Metrics					
SouthStar					
Average customers (in thousands)	557.7	563.6	555.5	(1.1%)	1.5%
Market share in Georgia	37.5%	38.2%	37.2%	(1.8)	2.7
AGL Networks					
% dark fiber miles leased – Atlanta	9.4%	1.6%	-	487.5	100.0
% dark fiber miles leased - Phoenix	5.8%	4.0%	-	45.0	100.0

2003 compared to 2002 The increase in EBIT of $19.5 million for 2003 compared to 2002 was primarily the result of increased earnings of $18.9 million from SouthStar and $1.5 million from US Propane, partially offset by decreased EBIT from AGL Networks of $0.6 million.

The $4.3 million increase in operating margin was due to a $3.0 million increase in AGL Networks' monthly recurring contract revenues, resulting from an increase in the number of executed leases and a $2.3 million sales-type lease completed in the first quarter of 2003. Also contributing to the year-over-year change is the recognition in 2002 of a $1.0 million feasibility fee; no such fees were recognized in 2003. The $2.7 million increase in operating expenses was primarily due to business growth at AGL Networks and higher corporate overhead costs.

The $17.9 million increase in other income was primarily the result of increased earnings from SouthStar of $18.9 million. The increased contribution from SouthStar was primarily due to disproportionate sharing of $5.9 million, higher volumes and related operating margin, additional 20% ownership interest (which contributed approximately $8.0 million), and lower bad debt and operating expenses. US Propane's earnings increased $1.5 million, primarily due to colder weather as compared to last year. The increases in other income were partially offset by a $2.0 million contract renewal payment in 2002 associated with the sale of Utilipro.

2002 compared to fiscal 2001 Effective March 2, 2001, we sold substantially all the assets of Utilipro for $17.9 million resulting in a pretax gain of $10.9 million and an aftertax gain of $7.1 million, in fiscal 2001. Excluding this gain, the increase in EBIT in 2002 compared to fiscal 2001 was $13.2 million. The increase in EBIT of $13.2 million for 2002 compared to fiscal 2001 was primarily the result of increased earnings from SouthStar of $13.3 million. These increases in EBIT were offset by a $1.6 million decrease in EBIT at AGL Networks.

The $6.5 million decrease in operating margin was due to a decrease of $7.9 million in Utilipro's operating margin from its sale in March 2001. The decrease was offset by a $1.5 million increase in AGL Networks' operating margin due to growth of the business.

The $4.9 million decrease in operating expenses was due to the absence of $8.5 million of Utilipro's operating expenses. The decrease was offset by a $3.8 million increase in AGL Networks' operating expenses due to additional personnel to support the growth of the business

The $3.9 million increase in other income was primarily the result of increased earnings from SouthStar of $13.3 million due to lower bad debt expense as a result of an increase in credit quality of retail customers, lower wholesale costs and a $2.0 million contract renewal payment in 2002 associated with the sale of Utilipro. The increases were offset by a $10.9 million pretax gain recorded in 2001 for the sale of Utilipro.

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 the PUHCA and state regulations. Our corporate segment also includes intercompany eliminations for transactions between our operating business segments.

Results of operations The results of operations for our corporate segment are as follows:

In millions	Calendar 2003	Calendar 2002	Fiscal 2001	2003 vs. 2002	2002 vs. 2001
Operating revenues	$0.1	($0.2)	$5.8	$0.3	($6.0)
Cost of sales	-	-	4.0	-	(4.0)
Operating margin	0.1	(0.2)	1.8	0.3	(2.0)
Total operating expenses	4.6	8.4	(5.9)	(3.8)	14.3
Loss on sale of Caroline Street campus	(5.6)	-	-	(5.6)	-
Operating (loss) income	(10.1)	(8.6)	7.7	(1.5)	(16.3)
Other loss	(1.3)	(1.5)	(9.1)	0.2	7.6
EBIT	($11.4)	($10.1)	($1.4)	($1.3)	($8.7)

2003 compared to 2002 The decrease in EBIT of $1.3 million for 2003 compared to 2002 was primarily the result of a loss of $5.6 million on the sale of the buildings and their contents at our Caroline Street campus. The decrease was offset by decreased operating expenses of $3.8 million for 2003 as compared to 2002.

The $3.8 million decrease in operating expenses was due to charges incurred in 2002 that were not incurred in 2003, which were not allocated to our operating segments in 2002. In 2002, we recorded $6.4 million for the termination of the automated meter reading contract, $1.6 million for the write-off of capital costs related to a terminated risk management software implementation project and $1.5 million in employee severance costs. These decreases were offset by 2003 expenses not allocated to our operating segments, consisting primarily of $5.3 million in increased compensation and benefit costs.

2002 compared to fiscal 2001 The decrease in EBIT of $8.7 million for 2002 compared to fiscal 2001 was due to operating expenses recorded in 2002 that were not allocated to our operating segments. We recorded a $6.4 million charge for the termination of the automated meter reading contract, $1.6 million for the write-off of capital costs related to a risk management software implementation project and $1.5 million in employee severance costs.

Results of Operations, three-month periods ended December 31, 2001 and 2000.

In this section, the results of operations for the three-month periods ended December 31, 2001 and 2000 are compared. See Note 16, "Financial Information for the Period of October 1, 2000 to December 31, 2000 (Unaudited)," for results of operations and earnings per share information for the three months ended December 31, 2000. The following is a reconciliation of our operating results to operating margin and EBIT for the three months ended December 31, 2001 and 2000:

In millions, except per share amounts	Three months ended Dec. 31, 2001	Three months ended Dec. 31, 2000	2001 vs. 2000
Operating revenues	$203.8	$295.4	($91.6)
Cost of gas	49.1	130.8	(81.7)
Operating margin	154.7	164.6	(9.9)
Operating expenses			
Operation and maintenance	68.1	72.2	(4.1)
Depreciation and amortization	23.2	26.1	(2.9)
Taxes other than income	6.0	10.4	(4.4)
Total operating expenses	97.3	108.7	(11.4)
Operating income	57.4	55.9	1.5
Other income	4.9	4.6	0.3
EBIT	62.3	60.5	1.8
Interest expense	23.8	24.7	(0.9)
Earnings before income taxes	38.5	35.8	2.7
Income taxes	13.6	13.3	0.3
Net income	$24.9	$22.5	$2.4
Earnings per common share			
Basic	$0.45	$0.41	$0.04
Diluted	$0.45	$0.41	$0.04
Weighted average number of common shares outstanding			
Basic	55.3	54.1	1.2
Diluted	55.6	54.5	1.1

Net Income The increase in net income of $2.4 million was primarily the result of increased asset management activity at Sequent (which was formed in January 2001), operational efficiencies at VNG and favorable interest rates, offset by warmer weather.

EBIT by Segment

The following table summarizes EBIT for each of our business segments:

In millions	Three months ended Dec. 31, 2001	Three months ended Dec. 31, 2000	2001 vs. 2000
Distribution operations	$59.8	$59.9	($0.1)
Wholesale services	3.4	-	3.4
Energy investments	3.6	6.6	(3.0)
Corporate	(4.5)	(6.0)	1.5
Consolidated EBIT	$62.3	$60.5	$1.8

Interest Expense The decrease in interest expense of $0.9 million was primarily a result of favorable interest rates on our commercial paper program and favorable interest rate swaps, offset by higher debt balances due to increases in working capital needs.

Income Taxes The increase in income taxes of $0.3 million was due primarily to an increase in income before income taxes of $2.7 million compared to the same period in 2000. The effective tax rate (income tax expense expressed as a percentage of pretax income) for the three months ended December 31, 2001 was 35.3% compared to 37.2% for the same period in 2000.

Distribution Operations

	Three months ended		
In millions	**Dec. 31, 2001**	**Dec. 31, 2000**	**2001 vs. 2000**
Operating revenues	$197.2	$286.2	($89.0)
Cost of gas	48.4	126.8	(78.4)
Operating margin	148.8	159.4	(10.6)
Operation and maintenance expenses	62.8	66.6	(3.8)
Depreciation and amortization	21.2	23.5	(2.3)
Taxes other than income	5.1	9.8	(4.7)
Total operating expenses	89.1	99.9	(10.8)
Operating income	59.7	59.5	0.2
Other income	0.1	0.4	(0.3)
EBIT	$59.8	$59.9	($0.1)

The decrease in EBIT of $0.1 million for the three months ended December 31, 2001 compared to the same period in 2000 was primarily the result of a $12.5 million decrease in operating margin primarily from warmer weather in the VNG service territory. This was offset by a $1.9 million increase in AGLC's margin as a result of gas carrying costs charged to Marketers due to higher inventory levels.

Operating expenses decreased $10.8 million, primarily from implementation of operational efficiencies at VNG and CGC of $2.1 million. VNG's franchise taxes decreased $2.1 million, offset by increased income taxes and the bankruptcy of a Marketer of $2.3 million in the quarter ended December 31, 2000.

Wholesale Services

	Three months ended		
In millions	**Dec. 31, 2001**	**Dec. 31, 2000**	**2001 vs. 2000**
Operating revenues	$6.5	$-	$6.5
Cost of sales	0.4	-	0.4
Operating margin	6.1	-	6.1
Operation and maintenance expenses	2.6	-	2.6
Depreciation and amortization	-	-	-
Taxes other than income	0.1	-	0.1
Total operating expenses	2.7	-	2.7
Operating income	3.4	-	3.4
Other income	-	-	-
EBIT	$3.4	$-	$3.4

The increase in EBIT of $3.4 million for the three months ended December 31, 2001 compared to the same period in 2000 was due to earnings from Sequent, which was formed in January 2001. Financial results for the three months ended December 31, 2001 were from Sequent's asset management activities.

Energy Investments

In millions	Three months ended Dec. 31, 2001	Dec. 31, 2000	2001 vs. 2000
Operating revenues	$0.4	$4.2	($3.8)
Cost of sales	0.3	-	0.3
Operating margin	0.1	4.2	(4.1)
Operation and maintenance expenses	1.7	4.8	(3.1)
Depreciation and amortization	-	0.4	(0.4)
Taxes other than income	0.1	0.2	(0.1)
Total operating expenses	1.8	5.4	(3.6)
Operating income	(1.7)	(1.2)	(0.5)
Other income	5.3	7.8	(2.5)
EBIT	$3.6	$6.6	($3.0)

The decrease in EBIT of $3.0 million was primarily due to losses incurred at US Propane and costs incurred by AGL Networks. Operating margin for energy investments was $0.1 million for the three months ended December 31, 2001 and $4.2 million for the same period in 2000. The decrease of $4.1 million was primarily due to the sale of Utilipro in March 2001.

Operating expenses for energy investments were $1.8 million for the three months ended December 31, 2001 and $5.4 million for the same period in 2000. The decrease of $3.6 million was primarily due to the sale of Utilipro, offset by expenses incurred by AGL Networks. Other income for energy investments was $5.3 million for the three months ended December 31, 2001 and $7.8 million for the same period in 2000. The decrease of $2.5 million was primarily due to losses incurred at US Propane.

Corporate

In millions	Three months ended Dec. 31, 2001	Dec. 31, 2000	2001 vs. 2000
Operating revenues	($0.3)	$5.0	($5.3)
Cost of sales	-	4.0	(4.0)
Operating margin	(0.3)	1.0	(1.3)
Total operating expenses	3.7	3.4	0.3
Operating loss	(4.0)	(2.4)	(1.6)
Other loss	(0.5)	(3.6)	3.1
EBIT	($4.5)	($6.0)	$1.5

The increase in EBIT of $1.5 million was primarily due to decreases in corporate expenses. Other losses for corporate were $0.5 million for the three months ended December 31, 2001 and $3.6 million for the same period in 2000. The decrease of $3.1 million was primarily due to corporate expenses of $2.0 million incurred in 2000.

Liquidity and Capital Resources

We rely on operating cash flow; short-term borrowings under our commercial paper program, which is backed by our supporting credit agreements (Credit Facility); and borrowings or stock issuances in the long-term capital markets to meet our capital and liquidity requirements. For the future, we believe these sources will be sufficient for our working capital needs, debt service obligations and scheduled capital expenditures. 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 availability of borrowings under our Credit Facility is subject to conditions specified within the Credit Facility, which we currently meet. These conditions include compliance with certain financial covenants and the continued accuracy of representations and warranties contained in the agreements. Although we had no borrowings outstanding under our Credit Facility at December 31, 2003, 2002 and 2001, our unused availability under our Credit Facility was limited by our total debt-to-capital ratio at December 31, 2002 and 2001, as represented in the table below:

In millions	**Dec. 31, 2003**	**Dec. 31, 2002**	**Dec. 31, 2001**
Unused availability under the Credit Facility	$500.0	$244.1	$110.7
Cash and cash equivalents	16.5	8.4	7.3
Total cash and available liquidity under the Credit Facility	$516.5	$252.5	$118.0

In January 2003, the FASB released FASB Interpretation No. (FIN) 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). For many of the guarantees or indemnification agreements we issue, FIN 45 requires disclosure of the nature of the guarantee and the maximum potential amount of future payments that could be required of us as the guarantor. The table below illustrates our expected commercial commitments that were outstanding as of December 31, 2003 and meet the disclosure criteria required by FIN 45:

		Commitments Due before December 31,			
In millions	Total	2004	2005 & 2006	2007 & 2008	2009 & Thereafter
Guarantees (1) (2)	$228.5	$228.5	-	-	-
Standby letters of credit, performance/ surety bonds	7.9	7.9	-	-	-
Total other commercial commitments	$236.4	$236.4	$-	$-	$-

(1) $176.2 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 affiliate, SouthStar. We guarantee 70% of SouthStar's obligations to Southern Natural Gas Company and its affiliate South Georgia Natural Gas Company (together referred to as SONAT) under certain agreements between the parties up to a maximum of $7.0 million if SouthStar fails to make payment to SONAT. 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 $42.3 million, which represents our share of SouthStar's maximum credit support obligation to AGLC under its tariff.

Contractual Obligations

Presented below is a summary of our contractual obligations as of December 31, 2003. These items are discussed in further detail in Note 9, "Commitments and Contingencies."

		Payments Due before December 31,			
In millions	Total	2004	2005 & 2006	2007 & 2008	2009 & Thereafter
Long-term debt (1)	$1,033.1	$77.0	$-	$-	$956.1
Pipeline charges, storage capacity and gas supply (2)	709.0	219.8	234.3	97.2	157.7
PRP costs (3)	404.3	81.6	162.0	160.7	-
Short-term debt	306.4	306.4	-	-	-
ERC (3)	83.0	40.3	22.8	3.8	16.1
Operating leases (4)	82.6	11.8	21.6	16.4	32.8
Communication/network service and maintenance	17.8	8.2	9.6	-	-
Pension contribution (5)	15.0	15.0	-	-	-
Total	$2,651.2	$760.1	$450.3	$278.1	$1,162.7

(1) Includes $225.3 million of Trust Preferred Securities, 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" (SFAS 13). However, this accounting treatment does not affect the future annual operating lease cash obligations as shown herein.
(5) We calculate the amount of funding using an actuarial method called the projected unit cost method. However, it is not necessarily required and we may fund lesser amounts in the future. We have not included expected contributions for years subsequent to 2004.

Cash flow from operating activities

We have historically had a working capital deficit, primarily as a result of our borrowings of short-term debt to finance the purchase of long-term assets, principally property, plant and equipment. Year-to-year changes in our operating cash flows are primarily the result of the following:

- changes in our operating results
- variability in the distribution of earnings we receive from our equity investments
- the timing associated with working capital items such as cash collections from our customers
- payments for operating expenses to our vendors and employees, income taxes and interest

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.

2003 compared to 2002 Our cash flow from operations in 2003 was $122.1 million, a decrease of $163.4 million from 2002. This decrease was primarily the result of increased spending for injection of natural gas inventories of approximately 11 Bcf. The weighted average cost of this inventory increased approximately 30% as compared to last year. In addition, we made $21.5 million in pension contributions this year as a result of our continued efforts to fully fund our pension liability. This was offset by increased net income of $24.9 million and cash received from SouthStar of $40.0 million.

2002 compared to fiscal 2001 Our cash flow from operations was $285.5 million for 2002, an increase of $185.7 million from fiscal 2001. This increase was primarily as a result of growth in transaction volumes in wholesale services and cash received of $42.2 million from the sale of natural gas inventories, primarily storage gas sold to Marketers, in excess of cash purchases. Also, the increase was a result of increased net income of $14.1 million.

Cash flow from investing activities

In 2003, 2002 and fiscal 2001, cash used in investing activities consisted primarily of property, plant and equipment expenditures. In 2003, our other investing activities included our cash payment of $20.0 million for the purchase of Dynegy's 20% interest in SouthStar. In 2002, we received $27.3 million in cash from SouthStar and US Propane. In fiscal 2001, we completed the acquisition of VNG, net of cash acquired, for $541.2 million; this was slightly offset by cash received of $17.9 million from the sale of Utilipro. The following table provides additional information on our actual and estimated property, plant and equipment expenditures and our total capital requirements:

In millions	Estimated Calendar 2004	Calendar 2003	Actual Calendar 2002	Fiscal 2001	2003 vs. 2002	2002 vs. 2001
Construction of distribution facilities	$88.6	$53.8	$61.8	$63.2	($8.0)	($1.4)
PRP (1)	87.5	51.3	47.6	50.0	3.7	(2.4)
Telecommunications	2.5	8.2	28.6	2.8	(20.4)	25.8
Other	46.4	45.1	49.0	39.7	(3.9)	9.3
Total property, plant and equipment expenditures	225.0	158.4	187.0	155.7	(28.6)	31.3
ERC (2)	40.3	32.4	36.9	31.6	(4.5)	5.3
Total capital requirements	$265.3	$190.8	$223.9	$187.3	($33.1)	$36.6

(1) These expenditures include removal costs. We estimate our total future capital expenditures related to the PRP to be $404.3 million. Capital expenditures under this program are expected to end June 30, 2008, unless the program is extended by the GPSC.

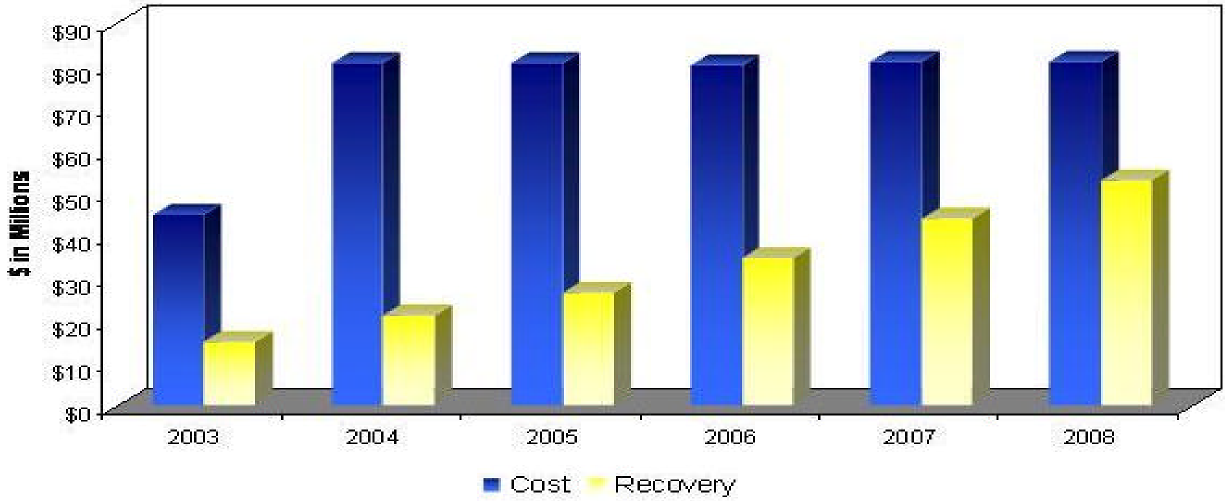
(2) These costs are not included in our cash flows from investing activities as they are not considered property, plant and equipment expenditures. They are considered a factor in our capital requirements as we estimate our cash requirements for future years.

2003 compared to 2002 The decrease of $28.6 million or 15.3% in property, plant and equipment expenditures for 2003 as compared to 2002 was primarily due to lower telecommunications expenditures of $20.4 million as a result of the completion of the metro Atlanta fiber network in 2002, and a decrease in construction of distribution facilities of $8.0 million associated with distribution operations. The $4.5 million decrease in the ERC expenditures was primarily due to work delays in Augusta and Savannah. The estimated ERC capital requirements for 2004 will increase as a result of these delays.

2002 compared to fiscal 2001 The increase of $31.3 million in property, plant and equipment expenditures for 2002 compared to fiscal 2001 was primarily from AGL Networks' completion of the metro Atlanta fiber network and the purchase of the Phoenix fiber network.

2004 compared to 2003 In 2004, we estimate that our total capital requirements will increase as a result of capital expenditures for construction of distribution facilities and the PRP. Our expected increase in the construction of distribution facilities is primarily from Pivotal's projects in 2004, including the propane facility at VNG.

As shown in the following chart, our PRP costs are expected to increase in the next five years primarily as a result of the replacement of larger-diameter pipe than in prior years, the majority of which is located in more densely populated areas. We expect the annual PRP costs through 2008 to be in the range of $75 - $80 million each year. The PRP recoveries shown in the chart are recorded as revenues and are based upon a formula that allows us to recover operation and maintenance costs in excess of those included in AGLC's base rates, depreciation expense and an allowed rate of return on capital expenditures. In the near term, the primary financial impact to us from the PRP is reduced cash flow from operating and investing activities, as the timing related to costs recovery does not match the timing of when costs are incurred.



Cash flow from financing activities

Our financing activities are primarily composed of borrowings and payments of short-term debt, payments of Medium-Term notes, borrowings of Senior Notes, cash dividends on our common stock and the issuance of common stock. Our Credit Facility financial covenants and the PUHCA require us to maintain a ratio of total debt-to-total capitalization of no greater than 70.0%. As of December 31, 2003, we were in compliance with this leverage ratio requirement. The components of our capital structure, as of the dates indicated, are summarized in the following table:

Dollars in millions	Dec. 31, 2003		Dec. 31, 2002	
Short-term debt	$306.4	13.4%	$388.6	18.3%
Current portion of long-term debt	77.0	3.3	30.0	1.4
Senior and Medium-Term notes (1)	730.8	32.0	767.0	36.1
Trust Preferred Securities (2)	225.3	9.9	227.2	10.7
Total debt	1,339.5	58.6	1,412.8	66.5
Common equity	945.3	41.4	710.1	33.5
Total capitalization	$2,284.8	100.0%	$2,122.9	100.0%

(1) Net of interest rate swaps of ($6.9) million in 2003.
(2) Net of interest rate swaps of $3.2 million in 2003 and $6.1 million in 2002.

Short-term Debt Our short-term debt is composed of borrowings under our commercial paper program and Sequent's line of credit. The commercial paper program is supported by our Credit Facility, which consists of a $200 million 364-day Credit Facility with a one-year term-out option that expires June 16, 2004 and a $300 million three-year Credit Facility that terminates on August 7, 2005. As of December 31, 2003, we had no outstanding borrowings under the Credit Facility.

In December 2003, Sequent's $15.0 million unsecured line of credit was increased to $25.0 million. Sequent used this unsecured line of credit solely for the posting of margin deposits for NYMEX transactions, and it is unconditionally guaranteed by us. This line of credit expires on July 2, 2004 and bears interest at the federal funds effective rate plus 0.5%. As of December 31, 2003, the line of credit had an outstanding balance of $2.9 million.

Long-term Debt On July 2, 2003, we issued $225.0 million in Senior Notes Due April 2013. The Senior Notes have an interest rate of 4.45% payable on April 15 and October 15 of each year, beginning October 15, 2003.We used the net proceeds to repay $203.8 million of our Medium-Term notes, discussed below, and approximately $19.6 million of short-term debt. In 2003, we made $207.3 million in Medium-Term note payments, as follows:

- In April 2003, we exercised our option to redeem two Medium-Term notes totaling $7.2 million before their scheduled maturity dates at a call premium. These notes were scheduled to mature in 2013 and 2014 with interest rates ranging from 7.4% to 7.5%.
- In July 2003, we exercised our option to redeem $65.3 million of Medium-Term notes at a call premium. These notes were scheduled to mature in 2013 and 2023 with interest rates ranging from 7.5% to 8.25%.
- In October 2003, we repaid on its original due date a $30.0 million Medium-Term note with an interest rate of 5.90%; and we exercised an option to redeem before their scheduled maturity dates a $10.0 million Medium-Term note, at par bearing interest at a rate of 6.0% scheduled to mature in 2006, and a $2.0 million Medium-Term note, at a premium, bearing interest at a rate of 6.85% scheduled to mature in 2020.
- In December 2003, we exercised our option to redeem $92.8 million of Medium-Term notes at a call premium. These notes were scheduled to mature in 2005 and 2013 bearing interest rates from 6.55% to 7.2%.

In 2002, we made $93.0 million in scheduled Medium-Term note payments using a combination of cash from operations and proceeds from the commercial paper program. On February 23, 2001, we issued $300.0 million in Senior Notes Due February 2011. These Senior Notes have an interest rate of 7.125% payable on January 14 and July 14. In May 2001, we issued and sold $150.0 million in principal amount of 8.0% Trust Preferred Securities. These Trust Preferred Securities are subject to mandatory redemption in May 2041 and may be redeemed early, beginning in 2006. We used the proceeds of the Senior Notes and Trust Preferred Securities to reduce our commercial paper balance and for general corporate purposes.

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 through our wholly owned subsidiary, AGL Capital, for the purpose of hedging the interest rate risk associated with our fixed-rate and variable-rate debt obligations. For more discussion of our interest rate swaps, see Note 3, "Risk Management."

Common Stock On February 14, 2003, we completed our public offering of 6.4 million shares of common stock. We priced the offering at $22.00 per share and generated net proceeds of approximately $136.7 million, which we used to repay outstanding short-term debt and for general corporate purposes.

Dividends on Common Stock On April 16, 2003, we announced a 3.7% increase in our common stock dividend, raising the quarterly dividend from $0.27 per share to $0.28 per share, which equates to an indicated annual dividend of $1.12 per share. In 2003, this increase in our common stock dividend along with the shares issued in connection with our equity offering resulted in an approximately $10 million increase in dividends paid on our common shares.

Shelf Registration We currently have an active shelf registration statement for up to $750 million of various capital securities, with remaining capacity of approximately $383 million. On September 23, 2003, we filed a second shelf registration with the SEC for authority to increase our capacity to $1.0 billion of various capital securities. We may seek additional financing through debt or equity offerings in the private or public markets at any time.

Credit Rating

Our credit ratings impact our ability to obtain short-term and long-term financing and the cost of such financing. In determining our credit ratings, the rating agencies consider a number of factors. Quantitative factors that appear to be given significant weight include, among other factors:

- earnings
- operating cash flow
- total debt outstanding
- total equity outstanding
- pension liabilities and funding status
- the level of capital expenditures and other commitments
- fixed charges such as interest expense, rent or lease payments
- payments to preferred stockholders
- liquidity needs and availability
- total debt-to-total capitalization ratios
- various ratios calculated from these factors

Qualitative factors appear to include, among other things, the stability of regulation in each jurisdiction, risks and controls inherent with wholesale services, predictability of cash flows, business strategy, management, corporate governance principles, board experience and independence, industry position and contingencies.

Our credit ratings may be subject to revision or withdrawal at any time by the assigning rating organization and you should evaluate each rating independently of any other rating. We cannot assure you that a rating will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. During 2003, no fundamental adverse shift occurred in our ratings profile.

The following table presents as of January 23, 2004 the credit ratings on our unsecured debt issues from the three major rating agencies. The ratings are all investment-grade status and the outlooks for all credit ratings are stable.

Type of Facility	Moody's	S&P	Fitch
Commercial paper	P-2	A-2	F-2
Medium-Term notes	A3	A-	A
Senior Notes	Baa1	BBB+	A-
Trust Preferred Securities	Baa2	BBB	BBB+

Our debt instruments and other financial obligations include provisions that, if not complied with, could require early payment, additional collateral support or similar actions. Our most important default events include

- a maximum leverage ratio
- minimum net worth
- insolvency events and nonpayment of scheduled principal or interest payments
- acceleration of other financial obligations
- change of control provisions

We do not have any trigger events in our debt instruments that are tied to changes in our specified credit ratings or our stock price and have not entered into any transaction that requires us to issue equity based on credit ratings or other trigger events. We are currently in compliance with all existing debt provisions and covenants.

Sequent has certain trade and/or credit contracts that have explicit credit rating trigger events in case of a credit rating downgrade. These rating triggers typically would give counterparties the right to suspend or terminate credit if our credit ratings were downgraded to non-investment grade status. Under such circumstances, we would need to post collateral to continue transacting business with some of our counterparties. Posting collateral would have a negative effect on our liquidity. If such collateral were not posted, our ability to continue transacting business with these counterparties would be impaired.

At December 31, 2003, if our credit ratings were downgraded to non-investment grade, the required amounts to satisfy potential collateral demands under such agreements between Sequent and its counterparties would have totaled $2.9 million. We believe the existing cash and available liquidity under our Credit Facility is adequate to fund these potential liquidity requirements.

Critical Accounting Policies

The selection and application of critical accounting policies are important processes that have progressed as our business activities have evolved and as a result of new accounting pronouncements. Accounting rules generally do not involve a selection among alternatives, but rather involve an implementation and interpretation of existing rules and the use of judgment as to the specific set of circumstances existing in our business. Each of the critical accounting policies 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.

Regulatory Accounting

We account for transactions within our distribution operations segment according to the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS 71). Applying this accounting policy allows us to defer expenses and income in the consolidated balance sheets as regulatory assets and liabilities when it is probable that those expenses and income will be allowed in the rate-setting process in a period different from the period in which they would have been reflected in the statements of consolidated income of an unregulated company. We then recognize these deferred regulatory assets and liabilities in our statements of consolidated income in the period in which we reflect the same amounts in rates.

If any portion of distribution operations ceased to continue to meet the criteria for application of regulatory accounting treatment for all or part of its operations, we would eliminate the regulatory assets and liabilities related to those portions ceasing to meet such criteria from our consolidated balance sheets and include them in our statements of consolidated income for the period in which the discontinuance of regulatory accounting treatment occurred.

Pipeline Replacement Program (PRP)

AGLC recorded a long-term liability of $322.7 million as of December 31, 2003 and $444.0 million as of December 31, 2002, which represented engineering estimates for remaining capital expenditure costs in the PRP. As of December 31, 2003, AGLC had recorded a current liability of $81.6 million, representing expected PRP expenditures for the next 12 months. These estimates are reported on an undiscounted basis.

The PRP ordered by the GPSC to be administered by AGLC requires, among other things, that AGLC replace all bare steel and cast iron pipe in AGLC's system in the state of Georgia within a 10-year period, beginning October 1, 1998. AGLC identified and provided to the GPSC in accordance with this order 2,312 miles of bare steel and cast iron pipe to be replaced. AGLC has subsequently identified an additional 188 miles of pipe subject to replacement under this program. If AGLC does not perform in accordance with this order, AGLC will be assessed certain nonperformance penalties. The order also provides for recovery of all prudent costs incurred in the performance of the program, which AGLC has recorded as a regulatory asset. The regulatory asset has two components:

- the costs incurred to date that have not yet been recovered through rate riders
- the future expected costs to be recovered through rate riders

Environmental Response Costs (ERC)

AGLC historically reported estimates of future remediation costs based on probabilistic models of potential costs. These estimates were reported on an undiscounted basis. As we continue to conduct the actual remediation and enter cleanup contracts, AGLC is increasingly able to provide conventional engineering estimates of the likely costs of many elements of its manufactured gas plant (MGP) program. These estimates contain various engineering uncertainties, and AGLC continuously attempts to refine and update these engineering estimates. In addition, AGLC continues to review technologies available for cleanup of AGLC's two largest sites, Savannah and Augusta, which, if proven, could have the effect of further reducing AGLC's total future expenditures. The following table shows components of AGLC's ERC liability as of December 31, 2003 and 2002:

In millions	Dec. 31, 2003	Dec.31, 2002	2003 vs. 2002
Projected engineering estimates and in-place contracts (1)	$66.4	$109.2	($42.8)
Estimated future remediation costs (1)	15.3	9.3	6.0
Administrative expenses (2)	2.7	1.3	1.4
Other expenses (2)	9.4	-	9.4
Cash payments for cleanup expenditures (3)	(10.8)	(14.8)	4.0
Accrued ERC	$83.0	$105.0	($22.0)

(1) As of September 30, 2003 and September 30, 2002.
(2) For the respective calendar years.
(3) Expenditures during the three months ended December 31, 2003 and December 31, 2002.

Our latest available estimate as of September 30, 2003 for those elements of the MGP program with in-place contracts or engineering cost estimates is $66.4 million. This is a reduction of $42.8 million from the estimate as of September 30, 2002 of projected engineering and in-place contracts, resulting from $36.5 million of program expenditures during the 12 months ended September 30, 2003 and a $6.3 million reduction in future cost estimates. For elements of the MGP program where AGLC still cannot perform engineering cost estimates, considerable variability remains in available estimates. For these elements, the estimated remaining cost of future actions at MGP sites is $15.3 million.

AGLC estimates certain other costs paid directly by AGLC related to administering the MGP program and remediation of sites currently in the investigation phase. Through January 2005, AGLC estimates the administration costs to be $2.7 million. Beyond January 2005, these costs are not estimable. For those sites currently in the investigation phase our estimate is $9.4 million, which is based upon preliminary data received during 2003 with respect to the existence of contamination of those sites. Our range of estimates for these sites is from $9.4 million to $15.1 million. We have accrued the low end of our range, or $9.4 million, as this is our best estimate at this phase of the remediation process.

The ERC liability is included in a corresponding regulatory asset. As of December 31, 2003, the regulatory asset was $179.4 million, which is a combination of the accrued ERC and unrecovered cash expenditures. AGLC's estimate does not include other potential expenses, such as unasserted property damage, 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 the amount cannot be reasonably forecast. AGLC's estimate also does not include any potential cost savings from the new cleanup technologies referenced above.

Revenue Recognition

Distribution Operations

The VNG and CGC rate structures include volumetric rate designs that allow recovery of costs through gas usage. VNG and CGC recognize revenues from sales of natural gas and transportation services in the same period in which they deliver the related volumes to customers. VNG and CGC bill and recognize sales revenues from residential and certain commercial and industrial customers on the basis of scheduled meter readings. In addition, VNG and CGC record revenues for estimated deliveries of gas, not yet billed to these customers, from the meter reading date to the end of the accounting period. We include these revenues in our consolidated balance sheets as unbilled revenue. Included in the rates charged by VNG and CGC is a WNA factor, which offsets the impact of unusually cold or warm weather on operating margins. VNG's weather normalization factor was introduced in November 2002 as a two-year experimental WNA program. For certain commercial and industrial customers and all wholesale customers, VNG and CGC recognize revenues based upon actual deliveries during the accounting period.

Wholesale Services

We record wholesale services revenues when physical sales of natural gas and natural gas storage volumes are delivered to the specified delivery point based on contracted or market prices. We reflect revenues from commodities sold as part of wholesale services' trading and derivative activities that are not designated as hedges, net of the cost of these sales. We record derivative transactions at their fair value.

Wholesale services accounts for derivative instruments under SFAS 133, which requires us to record all derivatives, as defined therein, in our balance sheets at their fair value. We reflect these derivatives in our consolidated balance sheets as risk management assets or liabilities. The market prices used in estimating the fair value of these contracts are based on our best estimates, utilizing information such as commodity exchange prices, over-the-counter quotes, volatility, time value, counterparty credit and the potential impact on market prices of liquidating positions in an orderly manner over a reasonable period of time under current market conditions.

When the portfolio market value changes, primarily due to newly originated transactions and the effect of price changes, wholesale services recognizes the change in value of derivative instruments as a gain or loss in revenues in the period of change. We recognize cash inflows and outflows associated with settlement of these risk management activities in operating cash flows, and we report these settlements as receivables and payables separately from risk management activities in the balance sheets as energy marketing receivables and trade payables. We adopted the net presentation provisions of the June 2002 consensus for EITF 02-03 on July 1, 2002. As required under that consensus, we present gains and losses from energy-trading activities on a net basis. This reclassification had no impact on our previously reported net income or shareholders' equity.

During 2003, 2002 and fiscal 2001, we accounted for derivative transactions in connection with our energy marketing activities in accordance with SFAS 133, and during 2002 and 2001 we accounted for nonderivative energy and energy-related activities in accordance with EITF 98-10. Under these methods, we recorded energy commodity contracts, including both physical transactions and financial instruments, at fair value, with unrealized gains and losses reflected in earnings in the period of change. Effective January 1, 2003, we adopted the final provisions of EITF 02-03, which rescinded EITF 98-10. Prior to EITF 02-03, wholesales services accounted for nonderivative energy instruments, such as contracts for storage capacity and physical natural gas inventory, at their fair value under EITF 98-10.

As a result of this adoption, effective January 1, 2003, wholesale services adjusted the fair value of its nonderivative trading instruments to zero and now accounts for them under the accrual method of accounting. In addition, its natural gas inventories are now recorded at the lower of average cost or market. The cumulative effect of a change in accounting principle resulted in a $12.6 million pretax reduction to income before the cumulative effect of a change in accounting principle ($7.8 million net of taxes), a decrease of $12.6 million to energy marketing and risk management assets, and a $4.8 million decrease to accumulated deferred income taxes in our accompanying consolidated balance sheets.

Energy Investments

SouthStar recognizes revenues from sales of natural gas and transportation services in the same period in which it delivers the related volumes to customers. SouthStar bills and recognizes sales revenues from residential and certain commercial and industrial customers on the basis of scheduled meter readings. In addition, SouthStar records revenues for estimated deliveries of gas, not yet billed to these customers, from the last meter reading date to the end of the accounting period. For certain commercial and industrial customers and all wholesale customers, SouthStar recognizes revenues based upon actual deliveries during the accounting period.

AGL Networks recognizes revenues attributable to leases of dark fiber pursuant to indefeasible rights-of-use (IRU) agreements as services are provided. Dark fiber IRU agreements generally require the customer to make a down payment upon execution of the agreement; however, in some cases AGL Networks receives up to the entire lease payment at the inception of the lease and recognizes revenue ratably over the lease term. As a result, we record deferred revenue in our consolidated balance sheets.

In addition, AGL Networks recognizes sales revenues upon the execution of certain sales-type agreements for dark fiber when the agreements provide for the transfer of legal title of the dark fiber to the customer at the end of the agreement's term. This sales-type accounting treatment is in accordance with EITF Issue No. 00-11, "Lessors' Evaluation of Whether Leases of Certain Integral Equipment Meet the Ownership Transfer Requirements of FASB Statement No. 13, *Accounting for Leases*, for Leases of Real Estate" (EITF 00-11), and SFAS No. 66, "Accounting for Sales of Real Estate" (SFAS 66), which provides that such transactions meet the criteria for sales-type lease accounting if the agreement obligates the lessor to convey ownership of the underlying asset to the lessee by the end of the lease term.

AGL Networks is obligated, under the dark fiber IRUs, to maintain the network in efficient working order and in accordance with industry standards. Customers contract with AGL Networks to provide maintenance services for the network. AGL Networks recognizes this maintenance revenue as services are provided. AGL Networks also engages in construction projects on behalf of customers. Projects are considered substantially complete upon customer acceptance, and the revenue and associated expenses are recorded at that time.

Accounting for Contingencies

Our accounting policies for contingencies cover a variety of business activities, including contingencies for potentially uncollectible receivables, rate matters, and legal and environmental exposures. We accrue for these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated in accordance with SFAS No. 5, "Accounting for Contingencies" (SFAS 5). We base our estimates for these liabilities on currently available facts and our estimates of the ultimate outcome or resolution of the liability in the future. Actual results may differ from estimates, and estimates can be, and often are, revised either negatively or positively, depending upon actual outcomes or changes in the facts or expectations surrounding each potential exposure.

Accounting for Pension Benefits

We have a defined benefit pension plan for the benefit of substantially all full-time employees and qualified retirees. We use several statistical and other factors that attempt to anticipate future events and to calculate the expense and liability related to the plan. These factors include our assumptions about the discount rate, expected return on plan assets and rate of future compensation increases. In addition, our actuarial consultants use subjective factors such as withdrawal and mortality rates to estimate the projected benefit obligation. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, or longer or shorter life spans of participants. These differences may result in a significant impact on the amount of pension expense recorded in future periods.

As of December 31, 2002, we recorded an additional minimum pension liability of $79.9 million, which resulted in an aftertax loss to other comprehensive income (OCI) of $48.5 million for 2002. At December 31, 2003, we reduced our minimum pension liability by approximately $13.7 million, which resulted in an aftertax gain to OCI of $8.2 million. This reflects the impact of our 2003 funding contributions to the plan and updated valuations for the projected benefit obligation and plan assets. To the extent that our future expenses and contributions increase as a result of the additional minimum pension liability, we believe that such increases are recoverable in whole or in part under future rate proceedings or mechanisms.

Equity market performance and corporate bond rates have a significant effect on our reported unfunded accumulated benefit obligation (ABO), as the primary factors that drive the value of our unfunded ABO are the assumed discount rate and the actual return on plan assets. Additionally, equity market performance has a significant effect on our market-related value of plan assets (MRVPA), which is a calculated value and differs from the actual market value of plan assets. The MRVPA recognizes the differences between the actual market value and expected market value of our plan assets and is determined by our actuaries using a five-year moving weighted average methodology. Gains and losses on plan assets are spread through the MRVPA based on the five-year moving weighted average methodology, which affects the expected return on plan assets component of pension expense.

A one-percentage-point increase in the assumed discount rate would have a negative impact on the ABO of approximately $30.5 million and would decrease pension expense by approximately $0.5 million. A one-percentage-point decrease in the assumed discount rate would have a positive impact on the ABO of approximately $34.0 million and would increase pension expense by approximately $2.5 million. Additionally, a one-percentage-point increase or decrease in the expected return on assets would decrease or increase our pension expense by approximately $2.6 million.

As of December 31, 2003, the market value of the pension assets was $258.9 million compared to a market value of $207.8 million as of December 31, 2002. The net increase of $51.1 million resulted from

- contributions of $6.5 million in February 2003
- contributions of $5.5 million in September 2003
- contributions of $9.5 million in October 2003
- contributions of $0.8 million in 2003 to our supplemental retirement plan
- an actual return on plan assets of $47.9 million less benefits paid of $19.1 million

Our $21.5 million in contributions to the pension plan this year reduced pension expense by approximately $0.8 million in 2003. The actual return on plan assets compared to the expected return on plan assets will have an impact on our benefit obligation as of December 31, 2003 and our pension expense for 2004. We are unable to determine how this actual return on plan assets will affect future benefit obligation and pension expense, as actuarial assumptions and differences between actual and expected returns on plan assets are determined at the time we complete our actuarial evaluation as of December 31, 2003. Our actual returns may also be positively or negatively impacted as a result of future performance in the equity and bond markets.

Accounting Developments

FIN 46 In January 2003, the FASB issued FASB Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46), which 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 (SPEs), the revised FIN 46 (FIN 46R) is now required to be applied no later than the end of the first fiscal year or interim reporting period ending after March 15, 2004. The original guidance under FIN 46 is still applicable, however, for all SPEs created prior to February 1, 2003 at the end of the first interim or annual reporting period ending after December 15, 2003. 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 will adopt FIN 46R for non-SPE entities as of March 31, 2004.

In June 1997 and March 2001, we established AGL Capital Trust I and AGL Capital Trust II (Trusts) to issue our Trust Preferred Securities. We consider the Trusts to be variable interest entities since the Trusts' total equity investment at risk is not sufficient to permit the Trusts to finance their own activities without additional subordinated financial support provided by any parties. We consider ourselves the primary beneficiary of the Trusts as we call options on our loans to the Trusts, thus entitling us to a majority of the Trusts' expected residual returns.

In addition, there is not one party that absorbs a majority of the Trusts' expected losses, as the Trust Preferred Securities are publicly traded and widely held. As such, we are the primary beneficiary of the Trusts and have consolidated the Trusts under FIN 46. We have, therefore, continued to classify amounts related to the Trust Preferred Securities as "Subsidiaries' obligated mandatorily redeemable preferred securities" within Capitalization in our consolidated balance sheets as of December 31, 2003.

We believe FIN 46R will have an impact on the accounting for the Trust Preferred Securities. We believe this will result in deconsolidating the trusts, and recording an investment representing our equity investment in the trusts and our liability to the trusts as a long-term liability. At December 31, 2003, we would have included in our balance sheet an asset of approximately $8 million representing our investment in the trusts, and a liability to the trusts totaling approximately $233 million, had we adopted early FIN 46R. This represents the loan payable to fund our investment in the trusts and the amount due to the trusts from the proceeds received from their issuances of preferred securities of $225 million. We are currently finalizing our evaluation of FIN 46R with respect to the Trust Preferred Securities, and will reflect the necessary adjustments in our March 31, 2004 financial statements.

We are also evaluating the potential impact of FIN 46R on our accounting for our investment in SouthStar (see "Energy Investments" section of our "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 13, "Equity Investments" for a discussion about the nature, purpose, size and activities of SouthStar), which will be effective in our March 31, 2004 financial statements. It is at least reasonably possible we will deem that SouthStar is a variable interest entity under its current structure and that we are the primary beneficiary. Additionally, we are in negotiations with Piedmont to revise the SouthStar partnership agreement, and we are also negotiating a management services agreement under which we would provide certain management functions to SouthStar. We believe that such changes to the SouthStar relationship would require us to re-evaluate whether we are the primary beneficiary of SouthStar under the provisions of FIN 46R. If we determine that we are the primary beneficiary pursuant to FIN 46R, we would be required to consolidate SouthStar and would reflect the necessary adjustments in our March 31, 2004 financial statements. As of December 31, 2003, our maximum exposure to loss is our equity investment in SouthStar of $71.2 million. Additionally, we have not provided any loans, guarantees or pledged collateral to SouthStar, and SouthStar's creditors have no recourse to our general credit.

SFAS 106 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.

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) on January 12, 2004. FSP 106-1 allowed companies to elect a one-time deferral of the recognition of the effects of the Medicare Prescription Drug Act in accounting for its plan under SFAS 106, and in providing disclosures related to the plan required by SFAS 132 (revised 2003) (see below). The FASB allowed the one-time deferral because of 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 because uncertainties exist regarding 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. We are currently evaluating the effects of the Medicare Prescription Drug Act on our other postretirement benefit plan and its participants and have elected the one-time deferral. Our accumulated postretirement obligation or net periodic postretirement benefit cost for 2003 does not reflect the effects of the Medicare Prescription Drug Act on our other postretirement plan. Additionally, once the specific authoritative guidance on the accounting for the federal subsidy is issued, such guidance could cause us to change previously reported information.

SFAS 132 On December 23, 2003, the FASB issued SFAS No. 132 (revised 2003), "Employers' Disclosures about Pensions and Other Postretirement Benefits--an amendment of FASB Statements No. 87, 88 and 106" (SFAS 132 revised 2003). SFAS 132 (revised 2003) is effective for fiscal years ending after December 15, 2003. Interim disclosure requirements under SFAS 132 (revised 2003) will be effective for interim periods beginning after December 15, 2003, and required disclosures related to estimated benefit payments will be effective for fiscal years ending after June 15, 2004.

SFAS 132 (revised 2003) replaces the disclosure requirements in SFAS No. 87, "Employers' Accounting for Pensions" (SFAS 87), SFAS No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits" (SFAS 88), and SFAS 106. SFAS 132 (revised 2003) addresses disclosures only and does not address measurement and recognition accounting for pension and postretirement benefits. SFAS 132 (revised 2003) requires additional disclosures related to the description of plan assets including investment strategies, plan obligations, cash flows and net periodic benefit cost of defined benefit pension and other defined benefit postretirement plans. Effective December 31, 2003, we adopted the disclosure requirements of SFAS No. 132 (revised 2003) with the exception of future expected benefit payments, which becomes effective for fiscal years ending after June 15, 2004 or December 31, 2004 for us.

SFAS 143 In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS 143), which is effective for fiscal years beginning after June 15, 2002. SFAS 143 requires legal obligations associated with the retirement of long-lived assets to be recognized at their fair value at the time the obligations are incurred. Upon initial recognition of a liability, that cost is recognized as an obligation and capitalized as part of the related long-lived asset. We adopted SFAS 143 on January 1, 2003, and it did not have a material impact on our financial position or results of operations because no legally enforceable retirement obligations were identified.

Our regulated entities currently accrue removal costs on many of our regulated long-lived assets through depreciation expense in accordance with rates approved by their state jurisdictions. In our current presentation, we have reclassified our accrual for removal costs from accumulated depreciation to a regulated liability as "Accumulated removal costs" for the years ended December 31, 2003.

SFAS 149 In April 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS 149), which amends and clarifies financial accounting and reporting for derivative instruments and for hedging activities, including the qualifications for the normal purchases and normal sales exception. The amendment reflects decisions made by the FASB in connection with issues raised about the application of SFAS 133. Generally, the provisions of SFAS 149 will be applied prospectively for contracts entered into or modified after June 30, 2003, and for hedging relationships designated after June 30, 2003. Adoption of SFAS 149 did not have a material effect on our consolidated results of operations, cash flows or financial position.

SFAS 150 In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity" (SFAS 150), which establishes standards for classification and measurement of certain financial instruments with characteristics of both liabilities and equities. Under SFAS 150, such financial instruments are required to be classified as liabilities in the statement of financial position. The financial instruments affected include mandatorily redeemable stock, certain financial instruments that require or may require the issuer to buy back some of its shares in exchange for cash or other assets, and certain obligations that can be settled with shares of stock. SFAS 150 is effective for all financial instruments entered into or modified after May 31, 2003 and was applied to our existing financial instruments beginning on July 1, 2003. Adoption of SFAS 150 did not have a material effect on our consolidated results of operations, cash flows or financial position.

EITF 02-03 During 2003, 2002 and 2001, wholesale services accounted for transactions in connection with energy marketing and risk management activities under the fair value, or mark-to-market method of accounting, in accordance with SFAS 133. During 2002 and 2001 we accounted for nonderivative energy and energy-related activities in accordance with EITF 98-10. Under these methods, we recorded energy commodity contracts (including physical transactions and financial instruments) at fair value and reflected unrealized gains and/or losses in earnings in the period of change. Effective January 1, 2003, we adopted EITF 02-03, which rescinded the provisions of EITF 98-10. For more information on our adoption of EITF 02-03 and its effects on our consolidated results of operations, cash flows and financial position, see "Results of Operations" under "Wholesale Services" and "Critical Accounting Policies" under "Revenue Recognition."

RISK FACTORS

The following are some of the factors that could affect our forward performance or could cause actual results to differ materially from those expressed or implied in our forward-looking statements. The risks and uncertainties described below are not the only ones we face. Additional risks and uncertainties that we are unaware of, or that we currently deem immaterial, also may become important factors that affect us.

Risks Related to Our Business

Risks related to the regulation of our businesses could impact the rates we are able to charge, our costs and our profitability.

Our businesses are subject to regulation by federal, state and local regulatory authorities. In particular, our distribution businesses are regulated by the SEC under the PUHCA, the FERC, the GPSC, the TRA and the VSCC. These authorities regulate many aspects of our distribution operations, including construction and maintenance of facilities, operations, safety, the rates that we can charge customers and the authorized cost of capital. Our ability to obtain rate increases and rate supplements to maintain our current rates of return depends upon regulatory discretion, and there can be no assurance that we will be able to obtain rate increases or rate supplements or continue receiving our currently authorized rates of return.

Deregulation in the natural gas industry is the separation of the provision and pricing of local distribution gas services into discrete components. Deregulation typically focuses on the separation of the gas distribution business from the gas sales business and is intended to cause the opening of the formerly regulated sales services to alternative unregulated suppliers of those services.

In 1997, the Georgia legislature enacted the Natural Gas Competition and Deregulation Act. To date, Georgia is the only state in the Southeast that has fully deregulated gas distribution operations, which ultimately resulted in AGLC exiting the retail natural gas sales business while retaining its gas distribution operations. Gas marketers then assumed the retail gas sales responsibility at deregulated prices. The deregulation process required AGLC to completely reorganize its operations and personnel at significant expense. It is possible that the legislature could reverse the deregulation process and require or permit AGLC to provide retail gas sales service once again. In addition, the GPSC has statutory authority on an emergency basis to order AGLC to temporarily provide the same retail gas service that it provided prior to deregulation. If either of these events were to occur, we would incur costs to reverse the restructuring process.

Our revenues, operating results and financial condition may fluctuate with the economy and its corresponding impact on our customers.

Our business is influenced by fluctuations in the economy. As a result, adverse changes in the economy can have negative effects on our revenues, operating results and financial condition. The level of economic and population growth in our regulated operations' service territories, particularly new housing starts, directly affects our potential for growing our revenues.

The cost of providing pension and postretirement health care benefits to eligible former employees is subject to changes in pension fund values and changing demographics, and may have a material adverse effect on our financial results.

We have a defined benefit pension plan for the benefit of substantially all full-time employees and qualified retirees. See the section "Critical Accounting Policies." The cost of providing these benefits to eligible current and former employees is subject to changes in the market value of our pension fund assets and changing demographics, including longer life expectancy of beneficiaries and an expected increase in the number of eligible former employees over the next five years.

We believe that sustained declines in equity markets and reductions in bond yields have and may continue to have a material adverse effect on the value of our pension funds. In these circumstances, we may be required to recognize an increased pension expense or a charge to our profit and loss account to the extent that the pension fund values are less than the total anticipated liability under the plans.

We face increasing competition, and if we are unable to compete effectively, our revenues, operating results and financial condition will be adversely affected.

The natural gas business is highly competitive, and we are facing increasing competition from other companies that supply energy, including electric companies and, in some cases, energy marketing and trading companies. In particular, the success of our investment in SouthStar is affected by the competition SouthStar faces from other energy marketers providing retail gas services in the Southeast. Natural gas competes with other forms of energy, such as electricity. The primary competitive factor is price. Changes in the price or availability of natural gas relative to other forms of energy and the ability of end-users to convert to alternative fuels affect the demand for natural gas.

Our wholesale services segment competes with larger, full-service energy providers, which may limit our ability to grow our business.

Wholesale services competes with national and regional full-service energy providers, energy merchants, and producers and pipelines for sales based on our ability to aggregate competitively priced commodities with transportation and storage capacity. Some of our competitors are larger and better capitalized than we are and have more national and global exposure than we do. This competition, and the addition of any new competitors, could negatively impact our wholesale services segment and our ability to grow our business.

Our asset management arrangements between Sequent and the affiliated LDCs and between Sequent and its nonaffiliated customers may not be renewed or may be renewed at lower levels, which could have a significant impact on Sequent's business.

Sequent currently manages the storage and transportation assets of AGLC, VNG, CGC and four nonaffiliated customers, under which Sequent shares profits it earns from the management of those assets with those customers and their customers. Sequent's results could be significantly impacted in the event that these agreements are not renewed or are amended or renewed with terms less favorable to us.

We have a concentration of credit risk in Georgia, which could expose a significant portion of our accounts receivable to collection risks.

We have a concentration of credit risk related to the provision of natural gas services to Georgia's Marketers. At September 30, 1998 (prior to deregulation), AGLC had approximately 1.4 million end-use customers in Georgia. In contrast, at December 31, 2003, AGLC had only 10 certificated and active Marketers in Georgia, four of which (based on customer count and including SouthStar) accounted for approximately 57.8% of our total operating margin for 2003. As a result, AGLC now depends on a very limited number of customers for revenues. The failure of these Marketers to pay AGLC could adversely affect AGLC's business and results of operations and expose it to difficulties in collecting AGLC's accounts receivable. AGLC obtains security support in an amount equal to a minimum of two times a Marketer's highest month's estimated bill from AGLC and also bills intrastate delivery service in advance rather than in arrears. Additionally, SouthStar markets directly to end-use customers and has periodically experienced credit losses as a result of cold weather, variable prices and customers' inability to pay.

Our profitability may decline if the counterparties to our transactions fail to perform in accordance with our agreements.

Wholesale services focuses on capturing the value from idle or underutilized energy assets, typically by executing transactions that balance the needs of various markets and time horizons. Wholesale services is exposed to the risk that counterparties to our transactions will not perform their obligations. Should the counterparties to these arrangements fail to perform, we might be forced to enter into alternative hedging arrangements, honor the underlying commitment at then-current market prices or return a significant portion of the consideration received for gas under a long-term contract. In such events, we might incur additional losses to the extent of amounts, if any, already paid to, or received from, counterparties.

We have a concentration of credit risk at Sequent that could expose us to collection risks.

We often extend credit to our counterparties. Despite performing credit analysis prior to extending credit and seeking to effectuate netting agreements, we are exposed to the risk that we may not be able to collect amounts owed to us. If the counterparty to such a transaction fails to perform and any collateral we have secured is inadequate, we could experience material financial losses.

We have a concentration of credit risk at Sequent, which could expose a significant portion of our credit exposure to collection risks. Approximately 72% of Sequent's credit exposure is concentrated in 20 counterparties. Although most of this concentration is with counterparties that are either load-serving utilities or end-use customers and that have supplied some level of credit support, default by any of these counterparties in their obligations to pay amounts due Sequent could result in credit losses that would negatively impact our wholesale services segment.

We are exposed to market risk and may incur losses in wholesale services.

The commodity, storage and transportation portfolios of wholesale services consist of contracts to buy and sell natural gas commodities, including contracts that are settled by the delivery of the commodity or cash. If the values of these contracts change in a direction or manner that we do not anticipate, we could experience financial losses from our trading activities. Value at risk (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. Based on a 95% confidence interval and employing a 1-day and a 10-day holding period for all positions, Sequent's portfolio of positions as of December 31, 2003 had a 1-day holding period VaR and 10-day holding period VaR of $0.3 million and $1.0 million, respectively.

Our hedging procedures may not fully protect our sales and net income from volatility.

To lower our financial exposure related to commodity price fluctuations, wholesale services may enter into contracts to hedge the value of our energy assets and operations. As part of this strategy, we may utilize fixed-price, forward, physical purchase and sales contracts; futures; and financial swaps and option contracts traded in the over-the-counter markets or on exchanges. However, we do not always hedge against the entire marketplace volatility exposure of our energy assets or our positions. To the extent we have unhedged positions or our hedging procedures do not work as planned, fluctuating commodity prices could cause our net income to be volatile.

Our accounting results may not be indicative of the risks we are taking or the economic results we expect due to changes in accounting for wholesale services.

Although wholesale services enters into various contracts to hedge the value of our energy assets and operations, the timing of the recognition of profits or losses on the hedges does not always match up with the profits or losses on the item being hedged. This can result in volatility in reported earnings from one period to the next that does not exist from an economic standpoint over the full life of the hedge and the hedged item.

Our business is subject to environmental regulation in all jurisdictions in which we operate and our costs to comply are significant, and any changes in existing environmental regulation could negatively affect our results of operations and financial condition.

Our operations and properties are subject to extensive environmental regulation pursuant to a variety of federal, state and municipal laws and regulations. Such environmental legislation imposes, among other things, restrictions, liabilities and obligations in connection with storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances into the environment. Environmental legislation also requires that our facilities, sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Our current costs to comply with these laws and regulations are significant to our results of operations and financial condition.

In addition, claims against us under environmental laws and regulations could result in material costs and liabilities. Existing environmental regulations could also be revised or reinterpreted, new laws and regulations could be adopted or become applicable to us or our facilities, and future changes in environmental laws and regulations could occur. With the trend toward stricter standards, greater regulation, more extensive permit requirements and an increase in the number and types of assets operated by us subject to environmental regulation, our environmental expenditures could increase in the future. Additionally, the discovery of presently unknown environmental conditions could give rise to expenditures and liabilities, including fines or penalties, which could have a material adverse effect on our business, results of operations or financial condition.

We could incur additional material costs for the environmental condition of some of our assets, including former manufactured gas plants.

We are generally responsible for all on-site and certain off-site liabilities associated with the environmental condition of the natural gas assets that we have operated, acquired or developed, regardless of when the liabilities arose and whether they are or were known or unknown. In addition, in connection with certain acquisitions and sales of assets, we may obtain, or be required to provide, indemnification against certain environmental liabilities. Before natural gas was widely available in the Southeast, we manufactured gas from coal and other fuels. Those manufacturing operations were known as manufactured gas plants, or MGPs, which we ceased operating in the 1950s.

We have identified 10 sites in Georgia and 3 in Florida where we, or our predecessors, own or owned all or part of an MGP site. We are required to investigate possible environmental contamination at those MGP sites and, if necessary, clean up any contamination. To date, we believe that some cleanup is likely at most of the sites and, as of December 2003, the remediation program was approximately 69% complete. As of December 31, 2003, projected costs associated with the MGP sites were $83.0 million. For elements of the MGP program where we still cannot perform engineering cost estimates, considerable variability remains in available future cost estimates.

The success of our telecommunications business strategy may be adversely affected by uncertain market conditions.

The current strategy of our telecommunications business is based upon our ability to lease telecommunications conduit and dark fiber in the Atlanta, Georgia and Phoenix, Arizona metropolitan areas. The market for these services, like the telecommunications industry in general, is very competitive, rapidly changing and currently suffering from lack of market commitments. We cannot be certain that growth in demand for these services will occur as expected. If the market for these services fails to grow as anticipated or becomes saturated with competitors, including competitors using alternative technologies, our investment in the telecommunications business may be adversely affected.

Future acquisitions and expansions, if any, may affect our business by increasing the level of our indebtedness and contingent liabilities and creating integration difficulties.

From time to time, we will evaluate and acquire assets or businesses, or enter into joint venture arrangements that we believe complement our existing businesses and related assets. These acquisitions and joint ventures may require substantial capital or the incurrence of additional indebtedness. Further, acquired operations or joint ventures may not achieve levels of revenues, operating income or productivity comparable to those of our existing operations, or may not otherwise perform as expected. Acquisitions or joint ventures may also involve a number of risks, including

- our inability to integrate operations, systems and procedures
- the assumption of unknown risks and liabilities
- diversion of management’s attention and resources
- difficulty retaining and training acquired key personnel

Risks Related to Our Corporate and Financial Structure

If we breach any of the material financial covenants under our various indentures, credit facilities or guarantees, our debt service obligations could be accelerated.

Our existing debt and the debt of certain of our subsidiaries contain a number of significant financial covenants. If we or any of these subsidiaries breach any of the financial covenants under these agreements, our debt repayment obligations under these agreements could be accelerated. In such event, we may not be able to refinance or repay all our indebtedness, which would result in a material adverse effect on our business, results of operations and financial condition.

We depend on our ability to successfully access the capital markets. Any inability to access the capital or financial markets may limit our ability to execute our business plan or pursue improvements that we may rely on for future growth.

We rely on access to both short-term money markets (in the form of commercial paper) and long-term capital markets as a source of liquidity for capital and operating requirements not satisfied by the cash flow from our operations. If we are not able to access financial markets at competitive rates, our ability to implement our business plan and strategy will be affected. Certain market disruptions may increase our cost of borrowing or affect our ability to access one or more financial markets. Such market disruptions could result from

- adverse economic conditions
- adverse general capital market conditions
- poor performance and health of the utility industry in general
- bankruptcy or financial distress of unrelated energy companies or Marketers in Georgia
- decreases in the market price of and demand for natural gas
- adverse regulatory actions that affect our local gas distribution companies
- terrorist attacks on our facilities or our suppliers

Increases in our leverage could adversely affect our competitive position and financial condition.

An increase in our debt relative to our total capitalization could adversely affect us by

- increasing the cost of future debt financing
- limiting our ability to obtain additional financing, if we need it, for working capital, acquisitions, debt service requirements or other purposes
- making it more difficult for us to satisfy our existing financial obligations
- requiring us to dedicate a substantial portion of our cash flow from operations to payments on our debt, which would reduce funds available to us for operations, future business opportunities or other purposes
- prohibiting the payment of dividends on our common stock or adversely impacting our ability to pay such dividends at the current rate
- increasing our vulnerability to adverse economic and industry conditions
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we compete

Changing rating agency requirements could negatively affect our growth and business strategy, and a downgrade in our credit rating could negatively affect our ability to access capital.

Standard & Poor's Ratings Group (S&P), Moody's Investors Service, Inc. (Moody's) and Fitch, Inc. (Fitch) have recently implemented new requirements for various ratings levels. In order to maintain our current credit ratings in light of these or future new requirements, we may find it necessary to take steps or change our business plans in ways that may affect our growth and earnings per share. S&P and Fitch currently assign our senior unsecured debt a rating of BBB+, and Moody's currently assigns our senior unsecured debt a rating of Baa1. Our commercial paper currently is rated A-2 by S&P and Moody's. If the rating agencies downgraded our ratings, particularly below investment grade, it may significantly limit our access to the commercial paper market, and our borrowing costs would increase. In addition, we would likely be required to pay a higher interest rate in future financings, and our potential pool of investors and funding sources would likely decrease.

Additionally, if our credit rating by either S&P or Moody's falls to non-investment grade status, we will be required to provide additional support for certain customers of our wholesale business. As of December 31, 2003, if our credit rating had fallen below investment grade, we would have been required to provide collateral of approximately $2.9 million to continue conducting our wholesale services business with certain counterparties.

The use of derivative contracts in the normal course of our business could result in financial losses that negatively impact our results of operations.

We use derivatives, including futures, forwards and swaps, to manage our commodity and financial market risks. We could recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities or if a counterparty fails to perform under a contract. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could adversely affect the value of the reported fair value of these contracts.

We depend on cash flow from our operations to pay dividends on our common stock.

We depend on dividends or other distributions of funds from our subsidiaries to pay dividends on our common stock. Payments of our dividends will depend on our subsidiaries' earnings and other business considerations and may be subject to statutory or contractual obligations. Additionally, payment of dividends on our common stock is at the sole discretion of our Board of Directors.

We are vulnerable to interest rate risk with respect to our debt, which could lead to changes in interest expense.

We are subject to interest rate risk in connection with the issuance of fixed-rate and variable-rate debt. In order to maintain our desired mix of fixed-rate and variable-rate debt, we use interest rate swap agreements and exchange fixed-rate and variable-rate interest payment obligations over the life of the arrangements, without exchange of the underlying principal amounts. See the section "Quantitative and Qualitative Disclosures about Market Risk." We cannot assure you that we will be successful in structuring such swap agreements to effectively manage our risks. If we are unable to do so, our earnings may be reduced.

<u>Risks Related to Our Industry</u>

Transporting and storing natural gas involves numerous risks that may result in accidents and other operating risks and costs.

Our gas distribution activities involve a variety of inherent hazards and operating risks, such as leaks, explosions and mechanical problems, which could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution, and impairment of our operations and substantial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. The location of pipelines and storage facilities near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. The occurrence of any of these events not fully covered by insurance could adversely affect our financial position and results of operations.

Terrorist activities and the potential for military and other actions could adversely affect our businesses.

The threat of terrorism and the impact of retaliatory military and other action by the United States and its allies may lead to increased political, economic and financial market instability and volatility in the price of natural gas that could affect our operations. In addition, future acts of terrorism could be directed against companies operating in the United States, and companies in the energy industry may face a heightened risk of exposure to acts of terrorism. These developments have subjected our operations to increased risks. The insurance industry has also been disrupted by these events. As a result, the availability of insurance covering risks against which we and our competitors typically insure may be limited. In addition, the insurance we are able to obtain may have higher deductibles, higher premiums and more restrictive policy terms.

Recent investigations and events involving the energy markets have resulted in an increased level of public and regulatory scrutiny in the energy industry and in the capital markets, resulting in increased regulation and new accounting standards.

As a result of the bankruptcy and adverse financial condition affecting several entities, particularly the bankruptcy filing by Enron, recently discovered accounting irregularities of various public companies and investigations by governmental authorities into energy trading activities, public companies have been under an increased amount of public and regulatory scrutiny. Recently discovered practices and accounting irregularities have caused regulators and legislators to review current accounting practices, financial disclosures and relationships between companies and their independent auditors. New laws, such as the Sarbanes-Oxley Act of 2002, and regulations to address these concerns have been and continue to be adopted, and capital markets and rating agencies have increased their level of scrutiny. Costs related to increased scrutiny may have an adverse effect on our business, financial condition and access to capital markets. In addition, the FASB or the SEC could enact new accounting standards that could impact the way we are required to record revenues, assets and liabilities. These changes in accounting standards could lead to negative impacts on our reported earnings or increases in our liabilities.

ITEM 7.(A) QUALITATIVE AND QUANTITATIVE DISCLOSURE 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.

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 financial and other derivative instruments that we use require payments to or receipt of payments from counterparties based on the differential between a fixed and variable price for the commodity, options or other contractual arrangements. We do not designate our derivative instruments that manage our risk exposure to energy prices as hedges under SFAS 133. Our determination of fair value considers various factors, including closing exchange or over-the-counter market price quotations, time value, and volatility factors underlying options and contractual commitments. The maximum terms of these maturities are less than 9 years and represent purchases (long) of 410.4 Bcf and sales (short) of 446.8 Bcf, with approximately 95% of these scheduled to mature in less than 2 years and the remaining 5% in 3 – 9 years.

The following table includes the fair values and average values of our energy marketing and risk management assets and liabilities as of December 31, 2003 and 2002. We base the average values on monthly averages for the 12 months ended December 31, 2003 and 2002.

	Asset			
	Average 12-Month Values		Value at:	
In millions	Calendar 2003	Calendar 2002	Dec. 31, 2003	Dec. 31, 2002
Natural gas contracts	$13.6	$18.6	$13.2	$24.7

	Liability			
	Average 12-Month Values		Value at:	
In millions	Calendar 2003	Calendar 2002	Dec. 31, 2003	Dec. 31, 2002
Natural gas contracts	$14.3	$12.6	$18.3	$17.9

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 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. On September 30, 2003, our RMC approved a proposal to change Sequent's 20-day VaR holding period to 10 days. This change was made to better align our risk reporting with that of our peers in the energy industry.

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. 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 12 months ended December 31, 2003 had the following 1-day and 10-day holding period VaRs:

In millions	1-day	10-day
Period end	$0.3	$1.0
12-month average	0.1	0.3
High	2.5	4.7
Low (1)	0.0	0.0

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

Under our risk management policy, we attempt to mitigate substantially all of our commodity price risk associated with Sequent's storage gas portfolio to 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, 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 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.

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

Energy Investments SouthStar utilizes financial contracts to hedge the price volatility of natural gas. SouthStar considers these financial contracts (futures, options and swaps) to be derivatives, with prices based on selected market indices. SouthStar reflects the derivatives transactions that qualify as cash flow hedges in its balance sheets at the fair values of the open positions with the corresponding unrealized gain or loss included in OCI. SouthStar reflects the derivatives transactions that are not designated as hedges in its balance sheets with the corresponding unrealized gains or losses included in cost of sales in SouthStar's statement of income.

SouthStar also 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" (EITF 99-02).

More than 90% of SouthStar's residential customers buy gas on a variable-price basis, and 6% buy gas on a fixed-price basis. SouthStar hedges the price risk associated with these fixed-price sales using physical contracts and derivative instruments.

Interest Rate Risk

Interest rate fluctuations expose our variable-rate debt to changes in interest expense and cash flows. Our policy is to manage interest expense using a combination of fixed-rate and variable-rate debt. To facilitate the achievement of desired fixed to variable-rate debt ratios, AGL Capital entered into interest rate swaps, whereby it agreed to exchange, at specified intervals, the difference between fixed and variable amounts calculated by reference to agreed-upon notional principal amounts. These swaps are designated to hedge the fair values of $100.0 million of the Senior Notes Due 2011, $100.0 million of the Senior Notes Due 2013 and $75.0 million of the $150.0 million Trust Preferred Securities Due in 2041.

Market Value of Interest Rate Swap Derivatives

Dollars in millions				Market Value as of:	
Notional Amount	Fixed-Rate Payment	Variable Rate Received	Maturity	Dec.31, 2003	Dec. 31, 2002
$75.0	8.0%	3-month LIBOR (1) Plus 131.5 bps (2)	May 15, 2041	$3.2	$6.1
$100.0	7.1%	6-month LIBOR Plus 340.0 bps	January 14, 2011	(1.8)	-
$100.0	4.5%	6-month LIBOR Plus 61.5 bps	April 15, 2013	(5.1)	-

(1) London Interbank Offered Rate
(2) Basis points.

At December 31, 2003, our variable-rate debt consisted of $303.5 million in commercial paper, $2.9 million of Sequent's line of credit and $275.0 million of the swapped portions of the $300.0 million Senior Notes Due 2011, $225 million Senior Notes Due 2013 and $150.0 million Trust Preferred Securities. Based on outstanding borrowings at quarter end, a 100-basis-point change in market interest rates from 1.3% to 2.3% at December 31, 2003 would result in a change in annual pretax expense of $5.8 million. As of December 31, 2003, $77.0 million of long-term fixed-rate obligations are scheduled to mature in the following 12 months. Any new debt obtained to refinance this obligation would be exposed to changes in interest rates.

Credit Risk

Distribution Operations AGLC has a concentration of credit risk where we charge out and collect from Marketers and poolers, costs for this segment. AGLC bills 10 Marketers in Georgia for its services. The credit risk exposure to Marketers varies with the time of the year with exposure at its lowest in the nonpeak summer months and highest 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 the natural gas commodity. These Marketers, in turn, bill end-use customers. 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 month's estimated bill from AGLC. For 2003, the four largest Marketers based on customer count, one of which was SouthStar, accounted for approximately 57.8% of our operating margin and 62.2% of distribution operations' operating margin.

In addition, AGLC bills intrastate delivery service to Marketers in advance rather than in arrears. We require security support in the form of cash deposits, letters of credit or surety bonds from acceptable issuers or corporate guarantees from investment-grade entities. The RMC reviews the adequacy of security support coverage, credit rating profiles of security support providers and payment status of each Marketer on a monthly basis. We believe that adequate policies and procedures have been put in place to properly quantify, manage and report on AGLC's credit risk exposure to Marketers.

AGLC also faces potential credit risk in connection with assignments to Marketers of interstate pipeline transportation and storage capacity. Although AGLC assigns this capacity to Marketers, in the event that a Marketer fails to pay the interstate pipelines for the capacity, the interstate pipelines would in all likelihood seek repayment from AGLC. The fact that some of the interstate pipelines require Marketers to maintain security for their obligations to the interstate pipelines arising out of the assigned capacity somewhat mitigates this risk.

Wholesale Services Sequent has established credit policies to determine and monitor the creditworthiness of counterparties, as well as the quality of pledged collateral. Sequent also utilizes master netting agreements whenever possible to mitigate exposure to counterparty credit risk. When 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.

Master netting agreements enable Sequent to net certain assets and liabilities by counterparty. Sequent also nets across product lines and against cash collateral provided the master netting and cash collateral agreements include such provisions. Additionally, Sequent may require counterparties to pledge additional collateral when deemed necessary. 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, which provides services to Marketers and utility and industrial customers, also has a concentration of credit risk as measured by its 30-day receivable exposure plus forward exposure. As of December 31, 2003, Sequent's top 20 counterparties represented approximately 72% of the total counterparty exposure of $190.2 million, derived by adding the top 20 counterparties' exposures divided by the total of Sequent's counterparties' exposures.

As of December 31, 2003, Sequent's counterparties, or the counterparties' guarantors, had a weighted average S&P equivalent credit rating of BBB compared to BBB+ at December 31, 2002. The S&P equivalent credit rating is determined by a process of converting the lower of the S&P or Moody's ratings to an internal rating ranging from 9 to 1, with 9 being equivalent to AAA/Aaa by S&P and Moody's and 1 being D or Default by S&P and Moody's. A counterparty that does not have an external rating is assigned an internal rating based on the strength of the financial ratios of that counterparty.

To arrive at the weighted average credit rating, the assigned internal rating for each counterparty is multiplied by the counterparty's credit exposure and summed for all counterparties. That sum is divided by the aggregate total counterparties' exposures, and this numeric value is then converted to an S&P equivalent. The following tables show Sequent's commodity receivable and payable positions as of December 31, 2003 and 2002:

Gross receivables	As of:		
In millions	Dec. 31, 2003	Dec. 31, 2002	Change
Receivables with netting agreements in place:			
Counterparty is investment grade	$288.3	$188.2	$100.1
Counterparty is non-investment grade	13.1	22.8	(9.7)
Counterparty has no external rating	8.8	25.1	(16.3)
Receivables without netting agreements in place:			
Counterparty is investment grade	14.7	3.7	11.0
Counterparty is non-investment grade	-	0.4	(0.4)
Counterparty has no external rating	-	-	-
Amount recorded on balance sheet	$324.9	$240.2	$84.7

Gross payables	As of:		
In millions	Dec. 31, 2003	Dec. 31, 2002	Change
Payables with netting agreements in place:			
Counterparty is investment grade	$205.4	$139.8	$65.6
Counterparty is non-investment grade	31.4	36.6	(5.2)
Counterparty has no external rating	45.0	28.4	16.6
Payables without netting agreements in place:			
Counterparty is investment grade	29.3	37.4	(8.1)
Counterparty is non-investment grade	2.5	2.2	0.3
Counterparty has no external rating	15.4	6.3	9.1
Amount recorded on balance sheet	$329.0	$250.7	$78.3

Energy Investments SouthStar has established the following credit guidelines and risk management practices for each customer type:

- SouthStar scores firm residential and small commercial customers using a national reporting agency and enrolls, without security, only those customers that meet or exceed SouthStar's credit threshold.
- SouthStar investigates potential interruptible and large commercial customers through reference checks, review of publicly available financial statements and review of commercially available credit reports.
- SouthStar assigns physical wholesale counterparties an internal credit rating and credit limit prior to entering into a physical transaction based on their Moody's, S&P and Fitch rating, commercially available credit reports and audited financial statements.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

AGL Resources Inc.
Consolidated Balance Sheets - Assets

In millions	As of: December 31, 2003	December 31, 2002
Current assets		
Cash and cash equivalents	**$16.5**	$8.4
Receivables		
Energy marketing	**324.9**	240.2
Gas	**65.3**	51.8
Other	**12.0**	28.1
Less allowance for uncollectible accounts	**(2.5)**	(2.3)
Total receivables	**399.7**	317.8
Income tax receivable	**-**	21.4
Unbilled revenues	**39.9**	33.9
Inventories		
Natural gas stored underground	**197.8**	107.4
LNG	**7.9**	5.9
Materials and supplies	**3.7**	4.9
Total inventories	**209.4**	118.2
Unrecovered ERC – current portion	**24.5**	21.8
Unrecovered PRP costs – current portion	**22.1**	15.0
Energy marketing and risk management assets – current portion	**13.1**	24.7
Unrecovered seasonal rates	**10.8**	9.3
Other current assets	**11.3**	15.9
Total current assets	**747.3**	586.4
Property, plant and equipment		
Property, plant and equipment	**3,402.2**	3,323.2
Less accumulated depreciation	**1,049.8**	1,129.0
Property, plant and equipment-net	**2,352.4**	2,194.2
Deferred debits and other assets		
Unrecovered PRP costs	**409.7**	499.3
Goodwill	**176.6**	176.2
Unrecovered ERC	**154.9**	173.3
Investments in equity interests	**101.3**	74.8
Unrecovered postretirement benefit costs	**9.4**	10.9
Restricted investment for purchase of telecommunications network	**-**	4.4
Energy marketing and risk management assets	**0.1**	-
Other	**26.1**	22.5
Total deferred debits and other assets	**878.1**	961.4
Total assets	**$3,977.8**	$3,742.0

See Notes to Consolidated Financial Statements.

AGL Resources Inc.
Consolidated Balance Sheets - Liabilities and Capitalization

In millions	As of: **December 31, 2003**	December 31, 2002
Current liabilities		
Energy marketing trade payable	**$329.0**	$250.7
Short-term debt	**306.4**	388.6
Accrued PRP costs – current portion	**81.6**	50.0
Current portion of long-term debt	**77.0**	30.0
Accounts payable-trade	**73.7**	91.1
Accrued ERC – current portion	**40.3**	41.3
Customer deposits	**24.4**	22.9
Accrued interest	**20.9**	19.2
Accrued wages and salaries	**18.5**	23.0
Energy marketing and risk management liabilities – current portion	**17.3**	17.9
Accrued taxes	**14.7**	16.0
Other current liabilities	**50.6**	65.1
Total current liabilities	**1,054.4**	1,015.8
Accumulated deferred income taxes	**376.3**	320.0
Long-term liabilities		
Accrued PRP costs	**322.7**	444.0
Accumulated removal costs	**102.4**	-
Accrued postretirement benefit costs	**51.0**	49.2
Accrued ERC	**42.7**	63.7
Accrued pension obligations	**38.5**	72.7
Energy marketing and risk management liabilities	**1.0**	-
Other long-term liabilities	**10.1**	-
Total long-term liabilities	**568.4**	629.6
Deferred credits		
Unamortized investment tax credit	**18.9**	20.2
Regulatory tax liability	**12.6**	13.5
Other deferred credits	**45.8**	38.6
Total deferred credits	**77.3**	72.3
Commitments and contingencies (see Note 9)		
Capitalization		
Long-term debt	**730.8**	767.0
Subsidiaries' obligated mandatorily redeemable preferred securities	**225.3**	227.2
Common shareholders' equity (see accompanying statements of consolidated common shareholders' equity)	**945.3**	710.1
Total capitalization	**1,901.4**	1,704.3
Total liabilities and capitalization	**$3,977.8**	$3,742.0

See Notes to Consolidated Financial Statements.

AGL Resources Inc.
Statements of Consolidated Income

In millions, except per share amounts	**Calendar 2003**	Calendar 2002	Transition Period	Fiscal 2001
Operating revenues	**$983.7**	$877.2	$203.8	$946.2
Operating expenses				
Cost of gas	**339.4**	268.2	49.1	327.3
Operation and maintenance	**282.7**	274.1	68.1	267.2
Depreciation and amortization	**91.4**	89.1	23.2	100.0
Taxes other than income taxes	**27.8**	29.3	6.0	32.8
Total operating expenses	**741.3**	660.7	146.4	727.3
Gain on sale of Caroline Street campus	**15.9**	-	-	-
Operating income	**258.3**	216.5	57.4	218.9
Equity in earnings of SouthStar	**45.9**	27.0	4.4	13.7
Other income (loss)	**1.9**	3.5	0.5	(7.3)
Donation to private foundation	**(8.0)**	-	-	-
Gain on sale of Utilipro	**-**	-	-	10.9
Interest expense	**(75.6)**	(86.0)	(23.8)	(97.4)
Earnings before income taxes	**222.5**	161.0	38.5	138.8
Income taxes	**86.8**	58.0	13.6	49.9
Income before cumulative effect of change in accounting principle	**135.7**	103.0	24.9	88.9
Cumulative effect of change in accounting principle, net of $4.8 in taxes	**(7.8)**	-	-	-
Net income	**$127.9**	$103.0	$24.9	$88.9
Basic earnings per common share:				
Income before cumulative effect of change in accounting principle	**$2.15**	$1.84	$0.45	$1.63
Cumulative effect of change in accounting principle	**(0.12)**	-	-	-
Basic earnings per common share	**$2.03**	$1.84	$0.45	$1.63
Diluted earnings per common share:				
Income before cumulative effect of change in accounting principle	**$2.13**	$1.82	$0.45	$1.62
Cumulative effect of change in accounting principle	**(0.12)**	-	-	-
Diluted earnings per common share	**$2.01**	$1.82	$0.45	$1.62
Weighted average number of common shares outstanding:				
Basic	**63.1**	56.1	55.3	54.5
Diluted	**63.7**	56.6	55.6	54.9

See Notes to Consolidated Financial Statements.

AGL Resources Inc.
Statements of Consolidated Common Shareholders' Equity

In millions, except par value and per share amounts	Common Stock	Premium on Common Stock	Earnings Reinvested	Other Comprehensive Income	Shares Held in Treasury and Trust	Total
Balance as of September 30, 2000	$289.1	$200.2	$197.8	$ -	($66.2)	$620.9
Comprehensive income:						
Net income	-	-	88.9	-	-	88.9
Other comprehensive income (OCI) – unrealized loss on interest rate hedge	-	-	-	(0.5)	-	(0.5)
Total comprehensive income						88.4
Dividends on common stock ($1.08 per share)	-	-	(58.6)	-	-	(58.6)
Benefit, stock compensation, dividend reinvestment and stock purchase plans	-	2.1	-	-	18.7	20.8
Stock award forfeitures	(0.1)	-	-	-	-	(0.1)
Other	-	0.5	(0.5)	-	-	-
Balance as of September 30, 2001	289.0	202.8	227.6	(0.5)	(47.5)	671.4
Comprehensive income:						
Net income	-	-	24.9	-	-	24.9
OCI – loss resulting from unfunded pension obligation	-	-	-	(0.6)	-	(0.6)
Total comprehensive income						24.3
Dividends on common stock ($0.27 per share)	-	-	(14.9)	-	-	(14.9)
Benefit, stock compensation, dividend reinvestment and stock purchase plans	-	1.1	(0.1)	-	8.5	9.5
Other	-	(0.1)	(0.1)	-	-	(0.2)
Balance as of December 31, 2001	289.0	203.8	237.4	(1.1)	(39.0)	690.1
Comprehensive income:						
Net income	-	-	103.0	-	-	103.0
OCI – loss resulting from unfunded pension obligation (net of tax benefit of $30.8)	-	-	-	(48.5)	-	(48.5)
Total comprehensive income						54.5
Dividends on common stock ($1.08 per share)	-	-	(60.5)	-	-	(60.5)
Benefit, stock compensation, dividend reinvestment and stock purchase plans (net of tax benefit of $1.1)	-	6.0	-	-	19.7	25.7
Other	-	-	(0.1)	0.4	-	0.3
Balance as of December 31, 2002	289.0	209.8	279.8	(49.2)	(19.3)	710.1
Comprehensive income:						
Net income	**-**	**-**	**127.9**	**-**	**-**	**127.9**
OCI - Gain resulting from unfunded pension obligation (net of tax of $5.5)				**8.2**		**8.2**
Unrealized gain from equity investments hedging activities (net of tax of $0.4)	**-**	**-**	**-**	**0.6**	**-**	**0.6**
Total comprehensive income						**136.7**
Dividends on common stock ($1.11 per share)	**-**	**-**	**(69.9)**	**-**	**-**	**(69.9)**
Issuance of common shares:						
Equity offering on February 14, 2003	**32.2**	**104.5**	**-**	**-**	**-**	**136.7**
Benefit, stock compensation, dividend reinvestment and stock purchase plans (net of tax benefit of $2.3)	**1.3**	**11.4**	**0.1**	**-**	**18.9**	**31.7**
Balance as of December 31, 2003	**$322.5**	**$325.7**	**$337.9**	**($40.4)**	**($0.4)**	**$945.3**

See Notes to Consolidated Financial Statements.

AGL Resources Inc.
Statements of Consolidated Cash Flows

In millions	**Calendar 2003**	Calendar 2002	Transition Period	Fiscal 2001
Cash flows from operating activities				
Net income	**$127.9**	$103.0	$24.9	$88.9
Adjustments to reconcile net income to net cash flow provided by operating activities				
Depreciation and amortization	**91.4**	89.1	23.2	101.3
Deferred income taxes, net of noncash items	**52.5**	81.9	14.0	6.7
Cumulative effect of change in accounting principle	**12.6**	-	-	-
Cash received from equity interests	**40.0**	-	-	-
Equity in earnings of unconsolidated subsidiaries	**(47.2)**	(27.2)	(5.2)	(11.1)
Gain on sale of Caroline Street campus	**(15.9)**	-	-	-
Gain on sale of Utilipro	**-**	-	-	(10.9)
Change in risk management assets and liabilities	**(0.7)**	(3.1)	(2.0)	(0.9)
Changes in certain assets and liabilities				
Payables	**61.0**	243.8	15.6	31.4
ERC – net	**(6.4)**	(17.9)	(3.5)	(15.7)
Pension liability – net	**(20.6)**	(6.1)	(7.1)	(0.9)
Receivables	**(66.5)**	(269.1)	(37.7)	(0.4)
Inventories and assigned natural gas stored underground	**(91.2)**	42.2	(6.8)	(83.3)
Other – net	**(14.8)**	48.9	(37.4)	(5.3)
Net cash flow provided by (used in) operating activities	**122.1**	285.5	(22.0)	99.8
Cash flows from investing activities				
Property, plant and equipment expenditures	**(158.4)**	(187.0)	(51.9)	(155.7)
Purchase of Dynegy's 20% ownership interest in SouthStar	**(20.0)**	-	-	-
Cash received from sale of Caroline Street campus	**22.7**	-	-	-
Cash received from equity interests	**1.8**	27.3	-	16.3
Acquisition of VNG, net of cash acquired	**-**	-	-	(541.2)
Cash received from sale of Utilipro	**-**	-	-	17.9
Net investment in joint ventures	**-**	-	-	3.5
Other	**8.8**	(0.7)	2.5	8.1
Net cash flow used in investing activities	**(145.1)**	(160.4)	(49.4)	(651.1)
Cash flows from financing activities				
Borrowings of Senior Notes	**225.0**	-	-	300.0
Equity offering	**136.7**	-	-	-
Sale of treasury shares	**18.9**	19.7	8.5	18.7
Sale of common stock	**12.7**	6.0	1.1	2.1
Dividends paid on common shares	**(69.9)**	(53.2)	(14.0)	(50.4)
Net payments and borrowings of short-term debt	**(82.2)**	3.9	81.3	162.2
Payments of Medium-Term notes	**(207.3)**	(93.0)	-	(20.0)
Issuance of Trust Preferred Securities	**-**	-	-	145.6
Other	**(2.8)**	(7.4)	(1.0)	(6.1)
Net cash flow provided by (used in) financing activities	**31.1**	(124.0)	75.9	552.1
Net increase in cash and cash equivalents	**8.1**	1.1	4.5	0.8
Cash and cash equivalents at beginning of period	**8.4**	7.3	2.8	2.0
Cash and cash equivalents at end of period	**$16.5**	$8.4	$7.3	$2.8
Cash paid during the period for				
Interest (net of allowance for funds used during construction)	**$59.6**	$73.3	$23.4	$83.3
Income taxes	**23.0**	15.3	39.3	37.3

See Notes to Consolidated Financial Statements.

> Note 1
Accounting Policies and Methods of Application

General

AGL Resources Inc. is an energy services holding company, and conducts substantially all 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 consolidated financial statements under the rules of the Securities and Exchange Commission (SEC). For a glossary of key terms and referenced accounting standards, see pages 4-5.

Basis of Presentation

Our consolidated financial statements include our accounts and those of our majority-owned and controlled subsidiaries. All significant intercompany items have been eliminated in consolidation. Certain amounts from prior periods have been reclassified to conform to our current presentation.

Consolidation Policy

We utilize the consolidation and equity methods to report our investments in our subsidiaries and other companies.

Consolidation. We utilize the consolidation method of accounting when we own a majority of the voting stock of the subsidiary or if we can otherwise exercise control over the entity. This means that our accounts are combined with the subsidiaries' accounts. Any intercompany profits between segments are not eliminated when such amounts are probable of recovery under the affiliates' rate regulation process. Additionally, intercompany balances and transactions are eliminated when the accounts are consolidated. Our consolidated financial statements include the accounts of the following subsidiaries:

- Atlanta Gas Light Company (AGLC)
- Virginia Natural Gas, Inc. (VNG)
- Chattanooga Gas Company (CGC)
- Sequent Energy Management, L.P. (Sequent)
- AGL Networks, LLC (AGL Networks)

The Equity Method. The equity method is utilized to account for and report investments where we hold a 20% to 50% voting interest, unless we can exercise control over the entity. Under the equity method, our ownership interest in the entity is reported as an investment within our consolidated balance sheets. Under the equity method, our share of the investments earnings or losses is reported in our statements of consolidated income as a component of other income.

We account for our investments in SouthStar Energy Services LLC (SouthStar) and US Propane LP (US Propane) using the equity method because we have significant influence over, but do not control, either of these entities. We recognize our share of earnings or losses from SouthStar in accordance with the provisions in SouthStar's partnership agreement that provide for allocation of additional income to us, also known as disproportionate sharing, if certain earnings thresholds are met. We recognized our equity in earnings of SouthStar based upon our ownership interest plus the amount recognized for disproportionate sharing.

For the period from January 1, 2003 through February 17, 2003, our ownership interest was 50%, and was 70% for the remainder of 2003 following our acquisition of Dynegy Inc.'s (Dynegy's) interest in SouthStar. We reached an agreement with Piedmont Natural Gas Company (Piedmont) in December 2003 that resolved issues over how the disproportionate sharing formula was applied. As a result, we recognized 80% of SouthStar's income for 2003 versus our 70% ownership interest. We recognize our share of earnings or losses from US Propane based on our ownership percentage.

Cash and Cash Equivalents

Our cash and cash equivalents consist primarily of cash on deposit, money market accounts and certificates of deposit with original maturities of three months or less.

Inventory

Our gas inventories and the inventories we hold for Marketers—that is, marketers who are certificated by the Georgia Public Service Commission (GPSC) to sell retail natural gas in Georgia --are accounted for using the weighted average cost method. Materials and supplies inventories are stated at the lower of average cost or market. At December 31, 2003, Sequent's natural gas inventory for reservoir and salt dome storage was recorded on an accrual basis. At December 31, 2003, Sequent's inventory held under park and loan arrangements was recorded at the lower of average cost or market. However, for those park and loan arrangements that are payable or repaid at determinable dates and at a specific point in time to third parties, the inventory was recorded at fair value. Sequent's inventories were recorded at fair market value at December 31, 2002.

In Georgia's competitive environment, Marketers, including AGLC's marketing affiliate SouthStar, began selling natural gas in 1998 to firm end-use customers at market-based prices. Part of the unbundling process, which resulted from deregulation that provides for this competitive environment, is the assignment to Marketers of certain pipeline services that AGLC has under contract. AGLC assigns, on a monthly basis, the majority of its pipeline storage services that it has under contract to the Marketers, along with a corresponding amount of inventory.

Property, Plant and Equipment

Distribution Operations. Property, plant and equipment expenditures consist of property and equipment that is in use, being held for future use and under construction. It is reported at its original cost, which includes

- material and labor
- contractor costs
- construction overhead costs
- an allowance for funds used during construction

Property retired or otherwise disposed of is charged to accumulated depreciation.

Wholesale Services, Energy Investments and Corporate. Property, plant and equipment expenditures include property that is in use and under construction, and is reported at cost. A gain or loss is recorded for retired or otherwise disposed of property.

Evaluation of Assets for Impairment

In August 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS 144), which superceded SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of" (SFAS 121). SFAS 144 requires us to review long-lived assets and certain intangibles for impairment annually or when events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable based on undiscounted future cash flows associated with the assets. Any impairment losses are reported in the period in which the recognition criteria are first applied based on the fair value of the asset. The adoption of SFAS 144 on January 1, 2002 had no impact on our financial position or results of operations. As of December 31, 2003, we believe that no asset impairments exist.

Goodwill and Other Intangible Assets

Goodwill We adopted SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS 142), effective October 1, 2001. Under SFAS 142, goodwill is no longer amortized. SFAS 142 further requires an initial goodwill impairment assessment in the year of adoption and annual impairment tests thereafter. We have included $176.6 million of goodwill in our consolidated balance sheets, of which $176.2 million is related to our acquisition of VNG in October 2000. Prior to our adoption of SFAS 142, our annual amortization of goodwill was $5.2 million before taxes. No impairment charges were recognized as a result of our initial impairment assessment, upon adoption of SFAS 142.

Subsequent to our adoption of SFAS 142, we annually assess goodwill for impairment purposes as of our fiscal year end, or December 31, and have not recognized any impairment charges for the three months ended December 31, 2001 or the years ended December 31, 2002 and 2003. We also assess changes in events and circumstances that may indicate an impairment of goodwill, principally through a review of financial results, changes in state and federal legislation and regulation, and the periodic regulatory filings for VNG, AGLC and CGC.

Intangible assets Sequent purchased three asset management contracts in the fourth quarter of 2003 for a combined purchase price of $6.3 million, all of which were recorded as intangible assets. During the fourth quarter, we amortized $0.1 million. The weighted average amortization period of these intangible assets as of December 31, 2003 was under three years. Over the next five years, the amount to be amortized will be

- $2.2 million in 2004
- $1.9 million in 2005
- $0.8 million in 2006
- $0.2 million in 2007 and 2008

Accumulated Deferred Income Taxes

The reporting of our assets and liabilities for financial accounting purposes differs from the reporting for income tax purposes. The principal differences between net income and taxable income relate to the timing of taxes due to the deferral benefits realized under bonus depreciation and investment tax credits historically available to us. The tax effects of the differences in those items are reported as deferred income tax assets or liabilities in our consolidated balance sheets. AGLC's and CGC's investment tax credits, which approximate to $18.9 million, have been deferred and are being amortized as credits to income over the estimated lives of the related properties in accordance with regulatory treatment.

Revenues

Distribution Operations. Revenues are recorded when services are provided to customers. Those revenues are based on rates approved by the GPSC, the VSCC and the Tennessee Regulatory Authority (TRA).

As required by the GPSC, in July 1998, AGLC began billing Marketers for each residential, commercial and industrial customer's distribution costs in equal monthly installments. As required by the GPSC, effective February 1, 2001, AGLC implemented a seasonal rate design for the calculation of each residential customer's annual straight-fixed-variable (SFV) capacity charge, which is billed to Marketers and reflects the historic volumetric usage pattern for the entire residential class. Generally, this change should result in residential customers being billed by Marketers for a higher capacity charge in the winter months and a lower charge in the summer months. This requirement has an operating cash flow impact, but does not change AGLC's revenue recognition. As a result, AGLC continues to recognize its residential SFV capacity revenues for financial reporting purposes in equal monthly installments.

Any difference between the billings under the seasonal rate design and the SFV revenue recognized is deferred and reconciled to actual billings on an annual basis. AGLC had unrecovered seasonal rates of approximately $10.8 million as of December 31, 2003 and $9.3 million as of December 31, 2002 (included as current assets in the consolidated balance sheets), related to the difference between the billings under the seasonal rate design and the SFV revenue recognized.

The VNG and CGC rate structures include volumetric rate designs that allow recovery of costs through gas usage. Revenues from sales and transportation services are recognized in the same period in which the related volumes are delivered to customers. VNG and CGC bill and recognize sales revenues from residential and certain commercial and industrial customers on the basis of scheduled meter readings. In addition, revenues are recorded for estimated deliveries of gas, not yet billed to these customers, from the meter reading date to the end of the accounting period. These are included in the consolidated balance sheets as unbilled revenue. For other commercial and industrial customers and all wholesale customers, revenues are based upon actual deliveries to the end of the period.

The TRA has authorized a weather normalization adjustment (WNA) rider for CGC. This rider is designed to offset the impact of unusually cold or warm weather on customer billings and operating margin.

On September 27, 2002, the VSCC approved a WNA program as a two-year experiment involving the use of special rates. The WNA program's purpose is to reduce the effect of weather on customer bills by reducing bills when winter weather is colder than normal and increasing bills when weather is warmer than normal. Under the terms of the program, if VNG requests to continue the WNA program after the two-year experiment, it is required to file a fully adjusted cost-of-service study along with the same schedules as would be required for a general rate case. It is possible the VSCC may require a general rate case prior to extending the WNA program. VNG plans to request an extension of the WNA program in 2004.

Wholesale Services and Energy Investments. Wholesale services and energy investments revenues are recorded when services are provided to customers. Intercompany profits from sales between segments are eliminated in the corporate segment and are recognized as goods or services sold to end-use customers. Transactions that qualify as derivatives under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133), are recorded at fair value with changes in fair value recorded as revenues in our statements of income.

Network Lease Accounting. Revenues from leases of dark fiber pursuant to indefeasible rights-of-use (IRU) agreements are recognized as services are provided. Dark fiber IRU agreements generally require the customer to make a down payment upon execution of the agreement; however, in some cases AGL Networks receives up to the entire lease payment at the inception of the lease and recognizes revenue ratably over the lease term. As a result, we record deferred revenue in our consolidated balance sheets.

In addition, AGL Networks recognizes sales revenues upon the execution of certain sales-type agreements for dark fiber when the agreements provide for the transfer of legal title to the dark fiber to the customer at the end of the agreement's term. This sales-type accounting treatment is in accordance with Emerging Issues Task Force (EITF) Issue No. 00-11, "Lessors' Evaluation of Whether Leases of Certain Integral Equipment Meet the Ownership Transfer Requirements of FASB Statement No. 13, *Accounting for Leases*, for Leases of Real Estate" (EITF 00-11), and SFAS No. 66, "Accounting for Sales of Real Estate" (SFAS 66), which provides that such transactions meet the criteria for sales-type lease accounting if the agreement obligates the lessor to convey ownership of the underlying asset to the lessee by the end of the lease term.

Cost of Gas

VNG and CGC charge their customers for the natural gas they consume using purchased gas adjustment (PGA) mechanisms set by the VSCC and the TRA, respectively. Under the PGA, VNG and CGC defer (that is, include as a current asset or liability in the consolidated balance sheets and exclude from the statements of consolidated income) the difference between the actual cost of gas and what is collected from customers in a given period. The deferred amount is either billed or refunded to VNG and CGC customers.

Stock-based Compensation

We have several stock-based employee compensation plans and account for these plans under the recognition and measurement principles of Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees" (APB 25), and related interpretations. For our stock option plans, we generally do not reflect stock-based employee compensation cost in net income, as options for 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 upon the fair value of our common stock at the balance sheet date since these awards constitute a variable plan under APB 25.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure– an amendment of FASB Statement No. 123" (SFAS 148). SFAS 148 provides alternative methods of transition for a voluntary change in accounting methods for stock-based employee compensation to the fair value based method of accounting for stock-based employee compensation. Under the fair value based method, compensation cost for stock options is measured when options are granted. In addition, SFAS 148 amends the disclosure requirements of SFAS No. 123, "Accounting for Stock-Based Compensation" (SFAS 123), which requires more prominent and more frequent disclosures in financial statements of the effects of stock-based compensation.

As of December 31, 2002, we adopted SFAS 148 through continued application of the intrinsic value method of accounting under APB 25, and we now disclose the effect on our net income and earnings per share of total stock-based employee compensation expense determined under the fair value based method. The following table illustrates the effect on our net income and earnings per share if we had applied the fair value recognition provisions of SFAS 123:

In millions, except per share amounts	**Calendar 2003**	Calendar 2002	Transition Period	Fiscal 2001
Net income, as reported	**$127.9**	$103.0	$24.9	$88.9
Add: Total stock-based expense compensation expense recorded, net of related tax effect	**0.1**	-	-	-
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effect	**(0.7)**	(1.9)	(0.6)	(2.4)
Pro forma net income	**$127.3**	$101.1	$24.3	$86.5
Earnings per share:				
Basic-as reported	**$2.03**	$1.84	$0.45	$1.63
Basic-pro forma	**$2.02**	$1.80	$0.44	$1.59
Diluted-as reported	**$2.01**	$1.82	$0.45	$1.62
Diluted-pro forma	**$2.00**	$1.79	$0.44	$1.58

Depreciation Expense

Depreciation expense for distribution operations is computed by applying composite, straight-line rates (approved by the GPSC, the VSCC and the TRA) to the investment of depreciable property. Distribution operations' composite straight-line depreciation rate for depreciable property excluding transportation equipment was approximately 2.7% during 2003, 2.8% during 2002 and 3.0% during fiscal 2001. As of May 1, 2002, the GPSC required a decrease of depreciation rates for AGLC, which decreased depreciation expense by $5.6 million in 2002 and approximately $9.6 million annually on a going forward basis. We depreciate transportation equipment on a straight-line basis over a period of 5 to 10 years. We compute depreciation expense for other segments on a straight-line basis over a period of 1 to 35 years.

Interest Expense

Our interest expense includes interest on our debt and preferred stock dividends.

Allowance for Funds Used During Construction (AFUDC)

We finance construction projects in Georgia, Virginia and Tennessee with debt, equity and funds from operations. The GPSC allows AGLC and the TRA allows CGC to record the cost of those funds as part of the cost of construction projects in our consolidated balance sheets and as AFUDC in the statements of consolidated income. We calculate AGLC's portion of AFUDC based upon a rate authorized by the GPSC. Beginning July 1, 1998, the GPSC authorized a rate of 9.11% for AFUDC, which increased to 9.16% effective May 1, 2002. The CGC portion of AFUDC is calculated based upon a rate of 9.08% authorized by the TRA. VNG's capital expenditures do not qualify for AFUDC treatment.

Comprehensive Income

Our comprehensive income includes net income and other gains and losses affecting shareholders' equity that accounting principles generally accepted in the United States (GAAP) excludes from net income. Such items consist primarily of unrealized gains and losses on certain derivatives and minimum pension liability adjustments.

SouthStar manages a portion of its commodity price risks through hedging activities using derivative financial instruments and physical commodity contracts. SouthStar uses financial contracts in the form of futures, options and swaps to hedge the price volatility of natural gas. For derivative transactions that are designated and qualify as cash flow hedges, SouthStar records the fair value of the open positions in its balance sheets, with the unrealized gain or loss recorded in other comprehensive income (OCI). In 2003, we recorded an aftertax gain to OCI of $0.6 million (net of income tax benefit of $0.4 million) for our 70% ownership interest in SouthStar's unrealized loss associated with its cash flow hedges.

Earnings per Common Share

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

We derive our potentially 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. No items are antidilutive. The following table shows the calculation of our diluted earnings per share for the periods presented if performance units currently earned under the plan ultimately vest and if stock options currently exercisable at prices below the average market prices are exercised:

In millions	**Calendar 2003**	Calendar 2002	Transition Period	Fiscal 2001
Denominator for basic earnings per share (weighted average shares outstanding)	**63.1**	56.1	55.3	54.5
Assumed exercise of potential common shares	**0.6**	0.5	0.3	0.4
Denominator for diluted earnings per share	**63.7**	56.6	55.6	54.9

Use of Accounting Estimates

Our management makes estimates and assumptions when preparing our financial statements under GAAP. These estimates and assumptions affect various matters, including

- reported amounts of certain assets and liabilities in our consolidated balance sheets as of the dates of the financial statements
- disclosure of contingent assets and liabilities as of the dates of the financial statements
- reported amounts of certain revenues and expenses in our statements of consolidated income during the reported periods

These estimates involve judgments with respect to, among other things, future economic factors that are difficult to predict and are beyond management's control. Consequently, actual amounts could differ from estimates.

> Note 2
Recent Accounting Pronouncements

Accounting Pronouncements Adopted in 2003

SFAS 132 On December 23, 2003, the FASB issued SFAS No. 132 (revised 2003), "Employers' Disclosures about Pensions and Other Postretirement Benefits--an amendment of FASB Statements No. 87, 88 and 106" (SFAS 132 revised 2003). SFAS 132 (revised 2003) is effective for fiscal years ending after December 15, 2003. Interim disclosure requirements under SFAS 132 (revised 2003) will be effective for interim periods beginning after December 15, 2003, and required disclosures related to estimated benefit payments will be effective for fiscal years ending after June 15, 2004.

SFAS 132 (revised 2003) replaces the disclosure requirements in SFAS No. 87, "Employers' Accounting for Pensions" (SFAS 87), SFAS No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits" (SFAS 88), and SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other than Pensions" (SFAS 106). SFAS 132 (revised 2003) addresses disclosures only and does not address measurement and recognition accounting for pension and postretirement benefits.

SFAS 132 (revised 2003) retains the disclosure requirements in the original SFAS 132, but requires additional disclosures related to the description of plan assets including investment strategies, plan obligations, cash flows and net periodic benefit cost of defined benefit pension and other defined benefit postretirement plans. Effective December 31, 2003, we adopted the disclosure requirements of SFAS 132 (revised 2003) with the exception of future expected benefit payments, which becomes effective for fiscal years ending after June 15, 2004 or December 31, 2004 for us.

SFAS 143 In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS 143), which is effective for fiscal years beginning after June 15, 2002. SFAS 143 requires legal obligations associated with the retirement of long-lived assets to be recognized at their fair value at the time the obligations are incurred. Upon initial recognition of a liability, that cost is recognized as an obligation and capitalized as part of the related long-lived asset. We adopted SFAS 143 on January 1, 2003, and it did not have a material impact on our financial position or results of operations because no legally enforceable retirement obligations were identified.

Our regulated entities currently accrue removal costs on many of our regulated long-lived assets through depreciation expense in accordance with rates approved by their state jurisdictions. In our current presentation, we have reclassified our accrual for removal costs from accumulated depreciation to a regulated liability as accumulated removal costs in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS 71), for the years ended December 31, 2003.

SFAS 149 In April 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS 149), which amends and clarifies financial accounting and reporting for derivative instruments and hedging activities, including the qualifications for the normal purchases and normal sales exception, under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133). The amendment reflects decisions made by the FASB in connection with issues raised about the application of SFAS 133. Generally, the provisions of SFAS 149 will be applied prospectively for contracts entered into or modified after June 30, 2003, and for hedging relationships designated after June 30, 2003. Adoption of SFAS 149 did not have a material effect on our consolidated results of operations, cash flows or financial position.

SFAS 150 In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity" (SFAS 150), which establishes standards for classification and measurement of certain financial instruments with characteristics of both liabilities and equities. Under SFAS 150, such financial instruments are required to be classified as liabilities in the statement of financial position. The financial instruments affected include mandatorily redeemable stock, certain financial instruments that require or may require the issuer to buy back some of its shares in exchange for cash or other assets, and certain obligations that can be settled with shares of stock. SFAS 150 is effective for all financial instruments entered into or modified after May 31, 2003, and we applied it to our existing financial instruments beginning on July 1, 2003. Adoption of SFAS 150 did not have a material effect on our consolidated results of operations, cash flows or financial position.

EITF 02-03 During 2003, 2002 and 2001, wholesale services accounted for transactions in connection with energy marketing and risk management activities under the fair value, or mark-to-market method of accounting, in accordance with SFAS 133, and during 2002 and 2001 we accounted for nonderivative energy and energy-related activities in accordance with EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 98-10). Under these methods, we recorded energy commodity contracts (including physical transactions and financial instruments) at fair value and reflected unrealized gains and/or losses in earnings in the period of change. Effective January 1, 2003, we adopted EITF 02-03, which rescinded the provisions of EITF 98-10 and reached two general conclusions:

- Contracts that do not meet the definition of a derivative under SFAS 133 should not be marked to fair market value.
- Revenues should be shown in the income statement net of costs associated with trading activities, whether or not the trades are physically settled.

The following resulted from our adoption of EITF 02-03:

- We adjusted the carrying value of our nonderivative trading instruments (principally storage capacity contracts) to zero and now account for them using the accrual method of accounting.
- We adjusted the value of our natural gas inventories used in wholesale services to the lower of average cost or market (they were previously recorded at fair value). This resulted in the cumulative effect of a change in accounting principle in our statements of consolidated income of $12.6 million ($7.8 million net of taxes), which resulted in a decrease of $12.6 million to our energy marketing and risk management assets and a decrease to accumulated deferred income taxes of $4.8 million in our consolidated balance sheets.
- We began reporting our trading activity on a net basis (revenues net of associated costs), effective July 1, 2002 and applied the net presentation provisions of EITF 02-03 to all prior periods. This reclassification had no impact on our previously reported net income or shareholders' equity.

Accounting Pronouncements Issued but Not Yet Adopted

FIN 46 In January 2003, the FASB issued FASB Interpretation No. (FIN) 46, "Consolidation of Variable Interest Entities" (FIN 46), which 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 (SPEs), the revised FIN 46 (FIN 46R) is now required to be applied no later than the end of the first fiscal year or interim reporting period ending after March 15, 2004. The original guidance under FIN 46 is still applicable, however, for all SPEs created prior to February 1, 2003 at the end of the first interim or annual reporting period ending after December 15, 2003. 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 will adopt FIN 46R for non-SPE entities as of March 31, 2004.

In June 1997 and March 2001, we established AGL Capital Trust I and AGL Capital Trust II (Trusts) to issue our Trust Preferred Securities. We consider the Trusts to be variable interest entities since the Trusts' total equity investment at risk is not sufficient to permit the Trusts to finance their own activities without additional subordinated financial support provided by any parties. We consider ourselves the primary beneficiary of the Trusts as we call options on our loans to the Trusts, thus entitling us to a majority of the Trusts' expected residual returns.

In addition, there is not one party that absorbs a majority of the Trusts' expected losses, as the Trust Preferred Securities are publicly traded and widely held. As such, we are the primary beneficiary of the Trusts and have consolidated the Trusts under FIN 46. We have therefore continued to classify amounts related to the Trust Preferred Securities as "Subsidiaries' obligated mandatorily redeemable preferred securities" within Capitalization in our consolidated balance sheets as of December 31, 2003.

We believe FIN 46R will have an impact on the accounting for the Trust Preferred Securities. We believe this will result in deconsolidating the Trusts and recording an investment representing our equity investment in the Trusts and our liability to the Trusts as a long-term liability. At December 31, 2003, we would have included in our balance sheet an asset of approximately $8 million representing our investment in the Trusts, and a liability to the Trusts totaling approximately $233 million, had we adopted early FIN 46R. This represents the loan payable to fund our investment in the Trusts and the amount due to the Trusts from the proceeds received from their issuances of preferred securities of $225 million. We are currently finalizing our evaluation of FIN 46R with respect to the Trust Preferred Securities, and will reflect the necessary adjustments in our March 31, 2004 financial statements.

We are also evaluating the potential impact of FIN 46R on our accounting for our investment in SouthStar, which will be effective in our March 31, 2004 financial statements. (For a discussion about the nature, purpose, size and activities of SouthStar, see "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the section "Energy Investments" and Note 13, "Equity Investments.") It is at least reasonably possible that we will deem that SouthStar is a variable interest entity under its current structure and that we are the primary beneficiary. Additionally, we are in negotiations with Piedmont to revise the SouthStar partnership agreement, and we are also negotiating a management services agreement under which we would provide certain management functions to SouthStar.

We believe that such changes to the SouthStar relationship would require us to re-evaluate whether we are the primary beneficiary of SouthStar under the provisions of FIN 46R. If we determine that we are the primary beneficiary pursuant to FIN 46R, we would be required to consolidate SouthStar and would reflect the necessary adjustments in our March 31, 2004 financial statements. As of December 31, 2003, our maximum exposure to loss is our equity investment in SouthStar of $71.2 million. Additionally, we have not provided any loans or guarantees, or pledged collateral to SouthStar, and SouthStar's creditors have no recourse to our general credit.

As of December 31, 2003, we have not consolidated SouthStar into our financial statements because it did not meet the definition of a variable interest entity or any of the applicable conditions of FIN 46, as indicated below:

- SouthStar currently operates financially independent of its equity owners, and does not require financial support in the form of guarantees or loans from its equity owners, or from any other entities, to finance its operations.
- SouthStar's activities were not conducted on behalf of an investor that had disproportionately few voting rights.
- The equity owners have the obligation to absorb actual and expected losses of SouthStar if they occur. They are not protected either directly or indirectly from losses, nor are they guaranteed a return by SouthStar or any other parties (customers, vendors or creditors) involved with SouthStar.
- The equity owners have the right to receive the expected residual returns of SouthStar if they occur, and the returns are not capped by governing documents or any other agreements.

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. We are currently evaluating the effects of the Medicare Prescription Drug Act on our other postretirement benefit plan and its participants, and have elected the one-time deferral. Our accumulated postretirement obligation or net periodic postretirement benefit cost for 2003 does not reflect the effects of the Medicare Prescription Drug Act on our other postretirement plan. Additionally, once the specific authoritative guidance on the accounting for the federal subsidy is issued, it could result in a change to previously reported information.

> Note 3
Risk Management

Financial Instruments, Derivatives and Hedging Activities

SFAS 133 as amended 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 a 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 requirements of SFAS 133 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 (OCI) 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. Two areas where SFAS 133 applies are interest rate swaps and gas commodity contracts at Sequent.

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 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. As of December 31, 2003, a notional principal amount of $275.0 million of these agreements effectively converted the interest expense associated with a portion of our Senior Notes and Trust Preferred Securities 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. As of December 31, 2003, our interest rate swaps consisted of the following:

- $100.0 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 December 31, 2003 was 4.5%. These interest rate swaps expire January 14, 2011, unless terminated earlier.
- $100.0 million principal amount of 4.45% Senior Notes Due 2013. We pay floating interest each April 15 and October 15 at six-month LIBOR plus 0.615%. The effective variable interest rate at December 31, 2003 was 1.8%. These interest rate swaps expire April 15, 2013, unless terminated earlier.
- $75.0 million principal amount of 8.0% Trust Preferred Securities 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 December 31, 2003 was 2.5%. These interest rate swaps expire May 15, 2041, unless terminated earlier.

We designated these 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.

Our interest rate swaps meet the conditions required to assume no ineffectiveness under SFAS 133, and, therefore, we have accounted for them using the "shortcut" method prescribed for fair value hedges by SFAS 133. Accordingly, we adjust the carrying value of each interest rate swap to its fair value at the end of each quarter, 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 rate swaps each quarter. The aggregate fair value of these interest rate swaps was a $3.7 million liability at December 31, 2003 and a $6.1 million asset at December 31, 2002.

Commodity-related derivative instruments We are exposed to risks associated with changes in the market price of natural gas. Through Sequent we use derivative financial instruments to reduce our exposure to the risk of changes in the prices of natural gas as discussed below. Additionally, SouthStar manages a portion of its commodity price risks through hedging activities using derivative financial instruments and physical commodity contracts. 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 storage gas portfolio to lock in the economic margin at the time we enter into gas purchase transactions for our storage gas. We purchase gas for storage when the difference in the current market price we pay to buy gas plus the cost to store the gas is less than the market price we could receive in the future, 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 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.

Gas that we purchase and inject into storage is accounted for 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, which is discussed in greater detail later in this note. Under EITF 02-03 we would recognize a loss in any period when the market price for gas is lower than our 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 statements 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 to substantially lock in the margin upon the sale of storage gas are accounted for at fair value and marked to market each period, with changes in fair value recognized as gains or losses in the period of change. This difference in accounting, the lower of average cost or market 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. Over time, gains or losses on the sale of gas storage inventory will be offset by losses or gains on the derivatives, resulting in the realization of the economic profit margin we originally expected. This accounting difference causes Sequent's earnings on its gas storage positions to be affected by natural gas price changes, even though the economic profits remain essentially unchanged.

The commodity-related activities of wholesale services, which includes Sequent, are monitored by our Risk Management Committee (RMC). The RMC is the committee of senior officers charged with the review and enforcement of our risk management policy. 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

Our risk management policy limits the use of derivative financial instruments and physical transactions within predefined risk tolerances associated with

- pre-existing or anticipated physical natural gas sales
- pre-existing or anticipated physical natural gas purchases
- system use and storage

Our commodity-related derivative financial instruments, which exclude the interest rate swaps discussed earlier, have a weighted average maturity of approximately 6.8 months based on volumes. At December 31, 2003, our commodity-related derivative financial instruments represented purchases (long) of 410.4 billion cubic feet (Bcf) and sales (short) of 446.8 Bcf with approximately 95% of these scheduled to mature in less than 2 years and the remaining 5% in 3-9 years. Excluding the cumulative effect of a change in accounting principle, our unrealized gains were \$0.7 million in 2003 and \$4.1 million in 2002.

Concentration of Credit Risk

Distribution operations Concentration of credit risk occurs at AGLC, where costs for distribution operations are charged out and collected from both Marketers and poolers in Georgia. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. The retail function includes customer service, billing, collections and the purchase and sale of the natural gas commodity. For 2003, the four largest Marketers, based on customer count (one of which is our partially owned affiliate, SouthStar), accounted for approximately 62.2% of the company's and 57.8% of distribution operations' operating margin.

Several factors are designed to mitigate our risks from the increased concentration of credit that has resulted from deregulation. The provisions of AGLC's tariff allow AGLC to obtain credit support in an amount equal to a minimum of two times a Marketer's highest month's estimated bill from AGLC. In addition, AGLC bills intrastate delivery service to Marketers in advance rather than in arrears. We accept credit support in the form of cash deposits, letters of credit/surety bonds from acceptable issuers and corporate guarantees from investment-grade entities. The RMC reviews the adequacy of credit support coverage, credit rating profiles of credit support providers and payment status of each Marketer on a monthly basis. We believe that adequate policies and procedures have been put in place to properly quantify, manage and report on AGLC's credit risk exposure to Marketers.

Wholesale services Sequent, which provides services to marketers and utility and industrial customers, also has a concentration of credit risk measured by 30-day receivable exposure plus forward exposure, which is highly concentrated in 20 of its customers. At December 31, 2003, Sequent's top 20 counterparties represented approximately 72% of the total counterparty exposure of $190.2 million, derived by adding the top 20 counterparties' exposures and dividing by the total of Sequent's counterparties' exposures.

As of December 31, 2003, Sequent's counterparties, or the counterparties' guarantors, had a weighted average Standard & Poor's (S&P) equivalent credit rating of BBB compared to BBB+ at December 31, 2002. The S&P equivalent credit rating is determined by a process of converting the lower of the S&P or Moody's Investors Service, Inc. (Moody's) ratings to an internal rating ranging from 9 to 1, with 9 being equivalent to AAA/Aaa by S&P and Moody's and 1 being D or Default by S&P and Moody's. A counterparty that does not have an external rating is assigned an internal rating based on the strength of the financial ratios of the counterparty. To arrive at the weighted average credit rating, the assigned internal rating for each counterparty is multiplied by the counterparty's credit exposure and summed for all counterparties. That total is divided by the aggregate total counterparties' exposures. This numeric value is converted to an S&P equivalent.

> 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	**Dec.31, 2003**	Dec.31, 2002	2003 vs. 2002
Regulatory assets			
Unrecovered PRP costs	**$431.8**	$514.3	($82.5)
Unrecovered ERC	**179.4**	195.1	(15.7)
Unrecovered postretirement benefit costs	**9.4**	10.9	(1.5)
Unrecovered seasonal rates	**10.8**	9.3	1.5
Unamortized call premium	**4.2**	-	4.2
Regulatory tax asset	**3.1**	3.4	(0.3)
Deferred PGA	**-**	7.6	(7.6)
Other	**0.6**	1.6	(1.0)
Total	**$639.3**	$742.2	($102.9)
Regulatory liabilities			
Accumulated removal costs	**$102.4**	$-	$102.4
Unamortized investment tax credit	**18.9**	20.2	(1.3)
Deferred PGA	**29.7**	18.0	11.7
Regulatory tax liability	**14.9**	15.8	(0.9)
Other	**2.8**	1.0	1.8
Total regulatory liabilities	**168.7**	55.0	113.7
Associated liabilities			
PRP costs	**404.3**	494.0	(89.7)
ERC	**83.0**	105.0	(22.0)
Total associated liabilities	**487.3**	599.0	(111.7)
Total regulatory and associated liabilities	**$656.0**	$654.0	$2.0

Our regulatory assets are recoverable through either rate riders or base rates specifically authorized by a state regulatory commission. Base rates are designed to provide both a recovery of cost and a return on investment during the period rates are in effect. As such, all of our regulatory assets are subject to review by the respective state regulatory commission during any future rate proceedings. It is our opinion that all regulatory assets are recoverable in future rate proceedings. We have not recorded any regulatory assets that are recoverable but are not yet included in base rates or contemplated in a rate rider.

All the regulatory assets included in the table above are included in base rates except for the unrecovered PRP costs, unrecovered ERC and the deferred purchased gas adjustment (PGA), which are recovered through specific rate riders. The rate riders that authorize recovery of unrecovered PRP costs and the deferred PGA include both a recovery of costs and a return on investment during the recovery period. The rate rider that authorizes the recovery of unrecovered ERC only allows for recovery of the costs incurred. The recovery period for ERC is five years after the expense is incurred. The regulatory liabilities are refunded to ratepayers through a rate rider or base rates. If the regulatory liability is included in base rates, the amount is reflected as a reduction to the rate base in setting rates.

Pipeline Replacement Program

The PRP, ordered by the GPSC to be administered by AGLC, requires, among other things, that AGLC replace all bare steel and cast iron pipe in AGLC's system in the state of Georgia within a 10-year period, beginning October 1, 1998. AGLC identified and provided to the GPSC in accordance with this order 2,312 miles of pipe to be replaced. AGLC has subsequently identified an additional 188 miles of pipe subject to replacement under this program. If AGLC does not perform in accordance with this order, AGLC will be assessed certain nonperformance penalties. October 1, 2003 marked the beginning of the sixth year of the 10-year PRP.

The order also provides for recovery of all prudent costs incurred in the performance of the program, which AGLC has recorded as a regulatory asset. AGLC will recover from end-use customers, through billings to Marketers, the costs related to the program net of any cost savings from the program. All such amounts will be recovered through a combination of SFV rates and a pipeline replacement revenue rider. The regulatory asset has two components:

- the costs incurred to date that have not yet been recovered through the rate rider
- the future expected costs to be recovered through the rate rider

AGLC has recorded a long-term regulatory asset of $409.7 million, which represents the expected future collection of both expenditures already incurred and expected future capital expenditures to be incurred through the remainder of the program. AGLC has also recorded a current asset of $22.1 million, which represents the expected amount to be collected from customers over the next 12 months. The amounts recovered from the pipeline replacement revenue rider during 2003, 2002, the transition period and fiscal 2001 were approximately $14.6 million, $7.5 million, $1.6 million and $3.7 million, respectively.

As of December 31, 2003, AGLC had recorded a current liability of $81.6 million, representing expected program expenditures for the next 12 months. AGLC anticipates that its capital expenditures for the PRP will end by June 30, 2008, unless we agree with the GPSC to an extension of the program.

AGLC capitalizes and depreciates the capital expenditure costs incurred from the PRP over the life of the assets. Operation and maintenance costs are expensed as incurred. Recoveries, which are recorded as revenue, are based on a formula that allows AGLC to recover operation and maintenance costs in excess of those included in AGLC's current base rates, depreciation expense, and an allowed rate of return on capital expenditures. In the near term, the primary financial impact to AGLC from the PRP is reduced cash flow from operating and investing activities, as the timing related to cost recovery does not match the timing of when costs are incurred. However, AGLC is allowed the recovery of carrying costs on the under-recovered balance resulting from the timing difference.

Environmental Response Costs

Before natural gas was widely available in the Southeast, AGLC or its predecessor companies manufactured gas from coal and other fuels. Those manufacturing facilities were known as manufactured gas plants (MGPs), which AGLC ceased operating in the 1950s. AGLC identified 13 sites in Georgia and Florida where AGLC or its predecessors operated MGPs. In connection with these operations, AGLC is aware of the presence of coal tar and certain other byproducts of the gas manufacturing process at or near some of these former sites. Based on investigations to date, AGLC believes that some cleanup will be required at most of these sites.

AGLC has active environmental remediation or monitoring programs in effect at 10 sites. Two of the three sites in Florida and one Georgia site are currently in the preliminary investigation or engineering design phase. Where soil remediation is required at our Georgia sites, the work is targeted to be completed by January 2005. As of December 31, 2003, our MGP remediation program was approximately 69% complete.

AGLC has historically reported estimates of future remediation costs for MGPs based on probabilistic models of potential costs. These estimates are reported on an undiscounted basis. As cleanup options and plans mature and cleanup contracts are entered into, AGLC is increasingly able to provide conventional engineering estimates of the likely costs of many elements of its MGP program. These estimates contain various engineering uncertainties, and AGLC continuously attempts to refine and update these engineering estimates. In addition, AGLC continues to review technologies available for the cleanup of AGLC's two largest sites, Savannah and Augusta, which, if proven, could have the effect of further reducing AGLC's total future expenditures.

Our last engineering estimate was as of September 30, 2003. This estimate projected costs associated with AGLC's engineering estimates and in-place contracts to be $66.4 million. This is a reduction of $42.8 million from the estimate as of September 30, 2002 of projected engineering and in-place contracts, resulting from $36.5 million of program expenditures incurred in the twelve months ended September 30, 2003 and a $6.3 million reduction in future cost estimates. 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 $15.3 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 $2.7 million. Beyond January 2005, these costs are not estimable.

For those sites currently in the investigation phase, our estimate is $9.4 million. This estimate is based upon preliminary data received during 2003 with respect to the existence of contamination of those sites. Our range of estimates for these sites is from $9.4 million to $15.1 million. We have accrued the low end of our range, or $9.4 million, as this is our best estimate at this phase of the remediation process. AGLC's ERC liability is composed of the following elements:

In millions	Dec. 31, 2003	Dec.31, 2002	2003 vs. 2002
Projected engineering estimates and in-place contracts (1)	$66.4	$109.2	($42.8)
Estimated future remediation costs (1)	15.3	9.3	6.0
Administrative expenses (2)	2.7	1.3	1.4
Other expenses (2)	9.4	-	9.4
Cash payments for cleanup expenditures (3)	(10.8)	(14.8)	4.0
Accrued ERC	$83.0	$105.0	($22.0)

(1) As of September 30, 2003 and September 30, 2002.
(2) For the respective calendar years.
(3) Expenditures during the three months ended December 31, 2003 and December 31, 2002.

The ERC liability is included in a corresponding regulatory asset. As of December 31, 2003, the regulatory asset was $179.4 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 the amount. The liability also does not include certain potential cost savings as described above.

AGLC has three ways of recovering investigation and cleanup costs. First, the GPSC has approved an ERC recovery rider. It allows recovery of the costs of investigation, testing, cleanup and litigation. Because of that 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. During 2003 and 2002, AGLC recovered $22.5 million and $17.2 million, respectively, 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 were no material recoveries from potentially responsible parties during 2003. The third way AGLC can recover costs is from the receipt of net profits from the sale of remediated property. There were no sales of remediated property during 2003. In December 2003, an MGP property in Georgia was sold, resulting in a $0.3 million reduction in 2003 MGP expenditures.

The remaining significant year of spending for this program is 2004. 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 December 31, 2003, the MGP expenditures expected to be incurred over the next 12 months are reflected as a current liability of $40.3 million. In addition, AGLC expects to collect $24.5 million in revenues over the next 12 months under the ERC recovery rider, which is reflected as a current asset.

> Note 5
Employee Benefit Plans

Substantially all our employees are eligible to participate in our employee benefit plans.

Pension Benefits

We sponsor a defined benefit retirement plan (Retirement Plan) for our employees. A defined benefit plan specifies the amount of benefits an eligible plan participant eventually will receive using information about the participant.

We generally calculate the benefits under the Retirement Plan based on age, years of service and pay. The benefit formula for the Retirement Plan is a career average earnings formula for participants under age 50. We utilize a final average earnings benefit formula for participants over age 50 as of July 1, 2000 and will continue to utilize the final average earnings benefit formula for such participants until June 2010, at which time we will convert those Retirement Plan participants to a career average earnings formula.

VNG employees transitioned from VNG's retirement plan to our Retirement Plan, effective January 1, 2002 for nonunion employees and January 1, 2003 for union employees. Therefore, we changed the benefit formula for these VNG employees from a final average earnings formula to the same career average earnings formula under our Retirement Plan, resulting in a reduction to the projected benefit obligation. In fiscal 2001, we recorded a curtailment loss of $0.3 million related to the early retirement of certain officers included in a supplemental retirement plan. The following tables present details about our pension plans:

In millions	As of or for the year ended: **Dec. 31, 2003**	Dec. 31, 2002
Change in benefit obligation		
Benefit obligation at beginning of year	**$290.0**	$268.2
Service cost	**4.3**	3.2
Interest cost	**19.0**	19.3
Plan amendment	**-**	(4.2)
Actuarial loss	**20.3**	22.3
Benefits paid	**(19.0)**	(18.8)
Benefit obligation at end of year	**$314.6**	$290.0
Change in plan assets		
Fair value of plan assets at beginning of year	**$207.8**	$247.3
Actual return on plan assets	**47.9**	(21.5)
Employer contribution	**22.3**	0.8
Benefits paid	**(19.1)**	(18.8)
Fair value of plan assets at end of year	**$258.9**	$207.8
Funded status		
Plan assets less than benefit obligation at end of year	**($55.7)**	($82.2)
Unrecognized net loss	**94.9**	101.9
Unrecognized prior service cost (benefit)	**(11.5)**	(12.5)
Accrued (prepaid) pension cost	**$27.7**	$7.2
Amounts recognized in the statement of financial position consist of		
Prepaid benefit cost	**$34.3**	$14.0
Accrued benefit liability	**(6.6)**	(6.8)
Accumulated OCI	**(66.2)**	(79.9)
Net amount recognized at year end	**($38.5)**	($72.7)

The accumulated benefit obligation (ABO) for our retirement plan was $297.4 million at December 31, 2003 and $280.5 million at December 31, 2002. Information for pension plans with an ABO in excess of plan assets:

	December 31, 2003	December 31, 2002
Projected benefit obligation	**$314.6**	$290.0
ABO	**297.4**	280.5
Fair value of plan assets	**258.9**	207.8

Components of net periodic benefit cost	**Calendar 2003**	Calendar 2002	Transition Period	Fiscal 2001
Service cost	**$4.3**	$3.2	$0.9	$3.2
Interest cost	**19.0**	19.3	4.8	18.5
Expected return on plan assets	**(22.4)**	(23.7)	(5.4)	(21.1)
Net amortization	**(0.9)**	(1.2)	(0.3)	(1.4)
Recognized actuarial (gain) loss	**1.8**	-	-	-
Net annual pension cost	**1.8**	(2.4)	-	(0.8)
Curtailment loss	**-**	-	-	0.3
Net annual pension cost after curtailments	**$1.8**	($2.4)	$-	($0.5)

Additional information	**December 31, 2003**	December 31, 2002
Increase (decrease) in minimum liability included in OCI	**($13.7)**	$79.3

Weighted average assumptions used to determine net periodic benefit cost for years ending:

	December 31, 2003	2002
Discount rate	**6.8%**	7.4%
Expected return on plan assets	**8.8%**	8.8%
Rate of compensation increase	**4.5%**	4.5%

Weighted average assumptions used to determine benefit obligations as of:

	Dec. 31, 2003	Dec. 31, 2002	Dec. 31, 2001	Sep. 30, 2001
Discount rate	**6.3%**	6.8%	7.4%	7.5%
Rate of compensation increase	**4.5%**	4.5%	4.5%	3.8%

We consider a number of factors in the determination and selection of our assumptions of the overall expected long-term rate of return on plan assets. We consider the historical long-term return experience of our assets, the current and expected allocation of our plan assets as well as expected long-term rates of return. These expected long-term rates of return are derived with the assistance of our investment advisors and are generally based on a 10-year horizon for various asset classes, our expected investments of plan assets and active asset management as opposed to investment in a passive index fund. Our expected allocation of plan assets is based on a diversified portfolio consisting of domestic and international equity securities, fixed income, real estate, private equities and alternative asset classes.

Our Retirement Plan's weighted average asset allocations at December 31, 2003 and 2002 and our target asset allocation ranges are as follows:

	Target Range Allocation of Assets	Actual Allocation on Weighted Average Basis 2003	Actual Allocation on Weighted Average Basis 2002
Equity	40%-85%	66.8%	58.5%
Fixed income	25%-50%	30.3%	34.3%
Real estate and other	0%-10%	0%	0%
Cash	0%-10%	2.9%	7.2%

We have a Retirement Plan Investment Committee (the Committee) that is appointed by our Board of Directors and is responsible for overseeing the investments of the Retirement Plan. Further, we have an Investment Policy (the Policy) for the Retirement Plan, which has a goal to preserve the Retirement Plan's capital and maximize investment earnings in excess of inflation within acceptable levels of capital market volatility. To accomplish this goal, the Retirement Plan assets are actively managed with the objective of optimizing long-term return while maintaining a high standard of portfolio quality and proper diversification.

The Policy's risk management strategy establishes a maximum tolerance for risk in terms of volatility to be measured at 75% of the volatility experienced by the S&P 500. We will further broadly diversify the Plan to minimize the risk of large losses in a single asset class. The Policy's permissible investments include domestic and international equities (including convertible securities and mutual funds), domestic and international fixed income (corporate and U.S. government obligations), cash and cash equivalents, and other suitable investments. The asset mix of these permissible investments are maintained within the Policy's target allocations as included in the table above, but the Committee can establish different allocations between various classes and/or investment managers in order to better achieve expected investment results.

Equity market performance and corporate bond rates have a significant effect on our reported unfunded ABO as the primary factors that drive the value of our unfunded ABO are the assumed discount rate and the actual return on plan assets. Additionally, equity market performance has a significant effect on our market-related value of plan assets (MRVPA), which is a calculated value and differs from the actual market value of plan assets. The MRVPA recognizes the differences between the actual market value and expected market value of our plan assets and is determined by our actuaries using a five-year moving weighted average methodology. Gains and losses on plan assets are spread through the MRVPA based on the five-year moving weighted average methodology, which affects the expected return on plan assets component of pension expense.

Our employees do not contribute to the Retirement Plan. We fund the plan annually by contributing at least the minimum amount required by applicable regulations and as recommended by our actuary. We calculate the amount of funding using an actuarial method called the projected unit credit cost method. However, we may also fund the Retirement Plan in excess of the minimum required amount. We expect to contribute $15 million in 2004.

Postretirement Benefits

We sponsor defined benefit postretirement health care and life insurance plans that cover all employees employed as of June 30, 2002 if they reach retirement age while working for us. The benefits under these plans are generally calculated based on age and years of service.

On July 1, 2002, we announced changes to the medical and dental benefits for all retirees. We no longer offer retiree medical benefits for anyone hired after July 1, 2002. Effective August 1, 2002, the retiree medical plan requires a 20% contribution by the retiree to the medical premium and a 50% contribution of the medical premium for spousal coverage. Effective September 1, 2002, the retiree will be required to contribute 100% of the dental premium. These plan amendments resulted in a reduction of $45.8 million of the benefit obligation in 2002.

The GPSC, the VSCC and the TRA each approved phase-ins that defer a portion of other postretirement benefits expense for future recovery. We recorded a regulatory asset for the total amount of $9.4 million as of December 31, 2003 and $10.9 million as of December 31, 2002. In addition, we recorded a regulatory liability for the total amount of $2.0 million as of December 31, 2003 and a $1.4 million liability as of December 31, 2002.

Effective December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Prescription Drug Act) was signed into law. This act 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 provide a prescription drug benefit.

The FASB issued FSP 106-1 on January 12, 2004, which allowed companies to elect a one-time deferral of the recognition of the effects of the Medicare Prescription Drug Act in accounting for its plan 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. Currently we are evaluating the effects of the Medicare Prescription Drug Act on our other postretirement benefit plan and its participants, and we have elected the one-time deferral. Our accumulated postretirement obligation or net periodic postretirement benefit cost for 2003 does not reflect the effects of the Medicare Prescription Drug Act on our defined benefit postretirement health care and life insurance plans. Additionally, once the specific authoritative guidance on the accounting for the federal subsidy is issued, such guidance could require us to update previously reported information.

The following tables present details about our postretirement benefits:

	As of or for the year ended:	
In millions	**Dec. 31, 2003**	Dec. 31, 2002
Change in benefit obligation		
Benefit obligation at beginning of year	**$128.9**	$148.0
Service cost	**1.4**	1.7
Interest cost	**8.3**	9.3
Plan amendments	**-**	(45.8)
Actuarial loss	**5.9**	25.9
Benefits paid	**(10.5)**	(10.2)
Benefit obligation at end of year	**$134.0**	$128.9
Change in plan assets		
Fair value of plan assets at beginning of year	**$38.4**	$43.8
Adjustment to the beginning-of-year assets of VNG	**-**	(1.2)
Actual return on plan assets	**8.0**	(4.2)
Employer contribution	**8.3**	10.2
Benefits paid	**(10.5)**	(10.2)
Fair value of plan assets at end of year	**$44.2**	$38.4
Funded status		
ABO in excess of plan assets	**($89.8)**	($90.5)
Unrecognized loss	**44.0**	45.0
Unrecognized transition amount	**0.8**	0.8
Unrecognized prior service cost (benefit)	**(4.0)**	(4.5)
Accrued benefit cost	**($49.0)**	($49.2)
Amounts recognized in the statement of financial position consist of		
Prepaid benefit cost	**$-**	$-
Accrued benefit liability	**(49.0)**	(49.2)
Accumulated OCI	**-**	-
Net amount recognized at year end	**($49.0)**	($49.2)

The following table presents details on the components of our net periodic benefit costs:

In millions	**Calendar 2003**	Calendar 2002	Transition Period	Fiscal 2001
Service cost	**$1.4**	$1.7	$0.3	$1.7
Interest cost	**8.3**	9.3	2.6	10.7
Expected return on plan assets	**(2.9)**	(3.3)	(0.8)	(2.9)
Amortization of transition amount	**(0.5)**	1.9	0.9	3.8
Amortization of regulatory asset	**1.8**	0.6	0.1	0.6
Net periodic postretirement benefit cost	**$8.1**	$10.2	$3.1	$13.9

Weighted average assumptions used to determine net periodic benefit cost for years ended:

	December 31,	
	2003	2002
Discount rate	**6.8%**	7.4%
Expected return on plan assets	**8.8%**	8.8%
Rate of compensation increase	**4.5%**	4.5%

Weighted average assumptions used to determine benefit obligations as of:

	Dec. 31, 2003	Dec. 31, 2002	Dec. 31, 2001	Sep. 30, 2001
Discount rate	**6.3%**	6.8%	7.4%	7.5%

We consider the same factors in the determination and selection of our assumptions of the overall expected long-term rate of return on plan assets as those considered in the determination and selection of the overall expected long-term rate of return on plan assets for our Retirement Plan.

For purposes of measuring our accumulated postretirement benefit obligation, the assumed pre-Medicare and post-Medicare health care inflation rates are as follows:

	Pre-Medicare Cost (pre-65 years old)		**Post-Medicare Cost (post-65 years old)**	
Assumed Health Care Cost Trend Rates at December 31	**2003**	**2002**	**2003**	**2002**
Health care costs trend assumed for next year	**10.0%**	10.0%	**12.0%**	12.0%
Rate to which the cost trend rate gradually declines	**5.0%**	5.5%	**5.0%**	5.5%
Year that the rate reaches the ultimate trend rate	**2010**	2008	**2013**	2011

Assumed health care cost trend rates have a significant effect on the amounts reported for our health care plans. A one-percentage-point change in the assumed health care cost trend rates would have the following effects:

	One-Percentage-Point	
In millions	Increase	Decrease
Effect on total of service and interest cost	$1.3	($1.0)
Effect on accumulated postretirement benefit obligation	13.9	(11.4)

Our investment policies and strategies, including target allocation ranges, are similar to those of our Retirement Plan. We fund the plan annually and retirees contribute 20% of medical premiums, 50% of the medical premium for spousal coverage and 100% of the dental premium. Our portion of the funding to the plan for 2004 is expected to be approximately $10.0 million. Our postretirement benefit plan's weighted-average asset allocations for 2002 and 2003 and our target asset allocation ranges are as follows:

	Target Asset Allocation Ranges	**Calendar 2003**	Calendar 2002
Equity	40%-85%	**58.9%**	58.4%
Fixed income	25%-50%	**39.9%**	39.8%
Real Estate and Other	0%-10%	**-**	-
Cash	0%-10%	**1.2%**	1.8%

Employee Savings Plan Benefits

We also sponsor the Retirement Savings Plus Plan (RSP), a defined contribution benefit plan in which the benefits a participant ultimately receives come from regular contributions to a participant account. Under the RSP, we made matching contributions to participant accounts in the following amounts:

- $4.4 million in 2003
- $3.8 million in 2002
- $1.2 million in the transition period
- $4.0 million in fiscal 2001

We also sponsor the Nonqualified Savings Plan (NSP), an unfunded, nonqualified plan similar to the RSP. The NSP provides an opportunity for eligible employees, who could reach the maximum contribution amount in the RSP, to contribute additional amounts for retirement savings. Our contributions to the NSP during 2003, 2002 and fiscal 2001 were not significant. As a result of the acquisition of VNG, employees of VNG became eligible to participate in the RSP and the NSP, effective October 1, 2000.

> Note 6
Stock-based Compensation Plans

Employee Stock-based Compensation Plans and Agreements

We currently sponsor the following stock-based compensation plans:

- The Long-Term Incentive Plan (LTIP) provides for grants of performance units, restricted stock, and incentive and nonqualified stock options to key employees. The LTIP currently authorizes the issuance of up to 6.6 million shares of our common stock.
- A predecessor plan, the Long-Term Stock Incentive Plan (LTSIP), provides for grants of restricted stock, incentive and nonqualified stock options, and stock appreciation rights (SARs) to key employees. Following shareholder approval of the LTIP, no further grants have been made under the LTSIP.
- The Officer Incentive Plan (Officer Plan) provides for a total of 600,000 shares of common stock that could be awarded to new-hire officers. The Officer Plan provides for grants of nonqualified stock options and restricted stock.
- Stock appreciation rights (SARs) are granted to key employees under individual agreements that permit the holder to receive cash in an amount equal to the difference between the fair market value on the date of exercise and the SAR base value. A total of 159,957 SARs currently are outstanding.
- We amended the Non-Employee Directors Equity Compensation Plan (Directors Plan), in which all nonemployee directors participate effective December 2002, to eliminate the granting of stock options. As a result, the Directors Plan provides for the issuance of restricted stock. It currently authorizes the issuance of up to 200,000 shares of our common stock.

The following table summarizes activity for key employees and nonemployee directors related to grants of stock options:

	Number of Options	Weighted Average Exercise Price
Outstanding-September 30, 2000	3,329,156	$19.05
Granted	1,172,450	21.43
Exercised	(604,742)	18.68
Forfeited	(337,354)	18.95
Outstanding-September 30, 2001	3,559,510	$19.90
Granted	438,368	20.19
Exercised	(391,708)	18.82
Forfeited	(18,669)	19.69
Outstanding-December 31, 2001	3,587,501	$20.06
Granted	988,564	21.49
Exercised	(785,853)	19.28
Forfeited	(156,255)	21.59
Outstanding-December 31, 2002	3,633,957	$20.55
Granted	**939,262**	**26.76**
Exercised	**(863,112)**	**20.08**
Forfeited	**(199,137)**	**22.00**
Outstanding-December 31, 2003	**3,510,970**	**$22.25**

Information about outstanding and exercisable options as of December 31, 2003 is as follows:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life (in years)	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
$13.75 to $17.49	21,592	2.2	$16.24	21,592	$16.24
$17.50 to $19.99	667,808	4.5	19.13	664,475	19.13
$20.00 to $24.10	1,921,968	6.5	21.24	1,452,191	21.09
$24.11 to $30.00	899,602	9.4	26.85	16,619	26.04
Outstanding-Dec. 31, 2003	**3,510,970**	**6.9**	**$22.25**	**2,154,877**	**$20.47**

Summarized below are outstanding options that are fully exercisable:

	Number of Options	Weighted Average Exercise Price
Exercisable-September 30, 2001	2,202,846	$19.43
Exercisable-December 31, 2001	2,371,540	$19.50
Exercisable-December 31, 2002	2,483,756	$20.07
Exercisable-December 31, 2003	**2,154,877**	**$20.47**

As of December 31, 2002, we adopted SFAS 148 through continued application of the intrinsic value method of accounting under APB 25, and we now disclose the effect on our net income and earnings per share of total stock-based employee compensation expense determined under the fair value based method. The following table illustrates the effect on our net income and earnings per share if we had applied the fair value recognition provisions of SFAS 123:

In millions, except per share amounts	**Calendar 2003**	Calendar 2002	Transition Period	Fiscal 2001
Net income:				
As reported	**$127.9**	$103.0	$24.9	$88.9
Pro forma	**$127.3**	$101.1	$24.3	$86.5
Earnings per share:				
Basic-as reported	**$2.03**	$1.84	$0.45	$1.63
Basic-pro forma	**$2.02**	$1.80	$0.44	$1.59
Diluted-as reported	**$2.01**	$1.82	$0.45	$1.62
Diluted-pro forma	**$2.00**	$1.79	$0.44	$1.58

In accordance with the fair value method of determining compensation expense, we utilized the Black-Scholes pricing model and the estimate below:

	Calendar 2003	Calendar 2002	Transition Period	Fiscal 2001
Expected life (years)	**7**	7	7	7
Interest rate	**3.8%**	4.6%	4.4%	5.4%
Volatility	**19.2%**	19.2%	19.6%	19.4%
Dividend yield	**4.2%**	5.0%	5.1%	5.0%
Fair value of options granted	**$3.75**	$2.92	$2.56	$3.26

Participants realize value from option grants or SARs only to the extent that the fair market value of our common stock on the date of exercise of the option or SAR exceeds the fair market value of the common stock on the date of the grant. The compensation costs that have been charged against income for performance units, restricted stock and other stock-based awards were $7.9 million and $2.2 million in 2003 and 2002, respectively. Such compensation costs were immaterial in the transition period and fiscal 2001.

Incentive and Nonqualified Stock Options

We grant incentive and nonqualified stock options at the fair market value on the date of the grant. The vesting of incentive options is subject to a statutory limitation of $100,000 per year under Section 422A of the Internal Revenue Code. Otherwise, nonqualified options generally become fully exercisable not earlier than six months after the date of grant and generally expire 10 years after that date.

Performance Units

In 2002, 1.5 million performance units were granted, of which 1.25 million were outstanding as of December 31, 2003. The vesting of these performance units is contingent upon achieving certain predefined stock performance criteria over the three-year measurement period. The outstanding performance units are entitled to dividend credit. The performance units are subject to certain transfer restrictions and are forfeited upon termination of employment. In addition, vesting may be accelerated upon a change in control. Participants are eligible for 10% vesting if minimum vesting is not achieved during the three-year measurement period. We did not grant performance units in 2003, the transition period or fiscal 2001.

Performance units that were granted in November 1999 vested in September 2002. Based on performance achievement and the accrual of dividend credit, a total of 10,254 shares of common stock were issued to the participants.

Stock Appreciation Rights (SARs)

We grant SARs, which are payable in cash, at fair market value on the date of grant. SARs generally become fully exercisable not earlier than 12 months after the date of grant and generally expire six years after that date. We recognize the intrinsic value of the SARs as compensation expense over the vesting period. Compensation expense for 2003 and 2002 was immaterial. The following table summarizes activity related to grants of SARs:

	Number of SARs	Weighted Average Exercise Price
Issued	155,212	$23.50
Exercised	(9,150)	23.50
Forfeited	(4,809)	23.50
Outstanding as of December 31, 2002	141,253	$23.50
Issued	**45,790**	**$24.30**
Exercised	**(17,718)**	**23.50**
Forfeited	**(9,368)**	**23.99**
Outstanding as of December 31, 2003	**159,957**	**$23.70**

Directors Plan

Under the Directors Plan, each nonemployee director receives an annual retainer that has an aggregate value of $60,000. At the election of each director, the annual retainer is paid in cash (with a $30,000 limit) and/or shares of our common stock or is deferred and invested in common stock equivalents under the 1998 Common Stock Equivalent Plan for Non-Employee Directors. Upon initial election to our Board of Directors, each nonemployee director receives 1,000 shares of common stock on the first day of service.

Restricted Stock Awards

Restricted stock awards generally are subject to some vesting restrictions. We awarded restricted stock, net of forfeitures, to key employees and nonemployee directors in the following amounts:

	Calendar 2003	Calendar 2002	Transition Period	Fiscal 2001
Employees	**244,128**	30,000	6,500	21,000
Nonemployee Directors	**12,152**	1,410	-	3,437
Total	**256,280**	31,410	6,500	24,437
Weighted Average Fair Value	**$27.15**	$23.19	$20.97	$22.14

In addition, 104,000 of the 256,280 shares awarded in 2003 are one-year performance shares. The vesting of these performance shares is contingent upon the company achieving certain predefined performance criteria over the one-year performance measurement period. Participants are entitled to vote and receive dividends on stock awards. The shares are subject to certain transfer restrictions and are forfeited upon termination of employment, absent a change of control.

Employee Stock Purchase Plan

Effective January 1, 2002, we established the Employee Stock Purchase Plan (ESPP), a nonqualified employee stock purchase plan for eligible employees. Under the ESPP, employees may purchase shares of our common stock during quarterly intervals at 85% of fair market value. Employee contributions under the ESPP may not exceed $25,000 per employee during any calendar year. Under the ESPP, 600,000 shares are available for purchase. The ESPP will continue in effect until January 31, 2005. Information about the ESPP during 2003 and 2002 is presented below:

	Calendar 2003	Calendar 2002
Shares purchased on the open market	**24,871**	12,594
Average per share purchase price of our common stock	**$22.08**	$23.22
Our purchase price discount paid	**$97,400**	$44,024

> Note 7
Financing

Dollars in millions	Year(s) Due	Dec. 31, 2003 Int. rate	Dec. 31, 2003 Outstanding	Dec. 31, 2002 Int. rate	Dec. 31, 2002 Outstanding
Short-term debt					
Commercial paper (1)	2004	1.2%	$303.5	1.8%	$388.6
Current portion of long-term debt	2004	7.0 – 7.75	77.0	5.9	30.0
Sequent line of credit (2)	2004	1.4	2.9	-	-
Total short-term debt (3)		**2.4%**	**$383.4**	**2.0%**	**$418.6**
Long-term debt - net of current portion					
Medium-Term notes					
Series A	2021	9.10%	$30.0	9.10%	$30.0
Series B	2012-2022	8.3 – 8.7	61.0	7.35 – 8.7	167.0
Series C	2014-2027	6.55 – 7.3	121.7	6.00 – 7.3	270.0
Senior Notes	2011-2013	4.45 - 7.125	525.0	7.125	300.0
AGL Capital interest rate swaps	2011-2013	1.80 – 4.52	(6.9)	-	-
Total Medium-Term and Senior notes			$730.8		$767.0
Trust Preferred Securities					
AGL Capital Trust I	2037	8.17%	$74.3	8.17%	$74.3
AGL Capital Trust II	2041	8.0	147.8	8.0	146.8
AGL Capital interest rate swaps	2041	2.45	3.2	2.7	6.1
Total Trust Preferred Securities			$225.3		$227.2
Total long-term debt (3)		**5.9%**	**$956.1**	**6.9%**	**$994.2**
Total short-term and long-term debt (3)		**4.9%**	**$1,339.5**	**5.5%**	**$1,412.8**

(1) The daily weighted average rate was 1.3% for 2003 and 2.2% for 2002.
(2) The daily weighted average rate was 1.6% for 2003 and 2.2% for 2002.
(3) Weighted average interest rate, including interest rate swaps if applicable.

Short-term Debt

Our short-term debt is composed of borrowings under our commercial paper program and Sequent's line of credit. The commercial paper program is supported by our Credit Facility, which consists of a $200.0 million 364-day Credit Facility with a one-year term-out option that was originally scheduled to expire on August 7, 2003 but was renewed until June 16, 2004, and a $300.0 million three-year Credit Facility that terminates on August 7, 2005.

Commercial paper As of January 23, 2004, we had no outstanding borrowings under the Credit Facility. Loans outstanding on the date the $200.0 million Credit Facility terminates may be converted into a term loan, which will mature in one installment no later than August 7, 2004. As of January 27, 2003, there were no outstanding borrowings under the Credit Facility. As of December 31, 2003, AGL Capital's outstanding commercial paper consists of short-term unsecured promissory notes with maturities ranging from 5 to 30 days.

Sequent line of credit In December 2003, Sequent's $15.0 million unsecured line of credit was increased to $25.0 million. This unsecured line of credit is used solely for the posting of exchange deposits and is unconditionally guaranteed by us. This line of credit bears interest at the federal funds effective rate plus 0.5% and has an expiration date of July 2, 2004.

Long-term Debt

Our long-term debt matures more than one year from the date of issuance and consists of Medium-Term notes Series A, Series B and Series C, which we issued under an indenture dated December 1, 1989, and Senior Notes. The notes are unsecured and rank on parity with all of our other unsecured indebtedness. The annual maturities of long-term debt for the five-year period ending December 31, 2008 are as follows:

- $77.0 million in 2004
- no maturities in 2005-2011
- $737.7 million in 2012 and beyond

Senior Notes In February 2001, we issued $300.0 million of Senior Notes with a maturity date of January 14, 2011. These Senior Notes have an interest rate of 7.125% payable on January 14 and July 14, beginning July 14, 2001. We fully and unconditionally guarantee the Senior Notes. The proceeds from the issuance were used to refinance a portion of the existing short-term debt under the commercial paper program.

In March 2003, we entered into interest rate swaps of $100.0 million to effectively convert a portion of the fixed-rate interest obligation on the $300.0 million in Senior Notes Due 2011 to a variable-rate obligation. We pay floating interest each January 14 and July 14 at six-month LIBOR plus 3.4%. The effective variable interest rate at December 31, 2003 was 4.5%. These interest rate swaps expire January 14, 2011, unless terminated earlier.

In July 2003, we issued $225.0 million in Senior Notes with a maturity date of April 15, 2013. The Senior Notes have an interest rate of 4.45% payable on April 15 and October 15 of each year, beginning October 15, 2003 with interest accruing from July 2, 2003. We used the net proceeds from the Senior Notes to repay $203.8 million of Medium-Term notes as well as approximately $19.6 million of short-term debt.

Additionally in July 2003, we entered into interest rate swaps of $100.0 million to effectively convert a portion of the fixed-rate interest obligation on the $225.0 million in Senior Notes Due 2013 to a variable-rate obligation. We pay floating interest on the variable-rate obligation resulting from the interest rate swap on April 15 and October 15 at six-month LIBOR plus 0.615%. The effective variable interest rate at December 31, 2003 was 1.8%. These interest rate swaps expire April 15, 2013, unless terminated earlier, and have been designated as fair value hedges under SFAS 133.

Medium-Term notes In April 2003, we exercised our option to redeem two Medium-Term notes totaling $7.2 million before their scheduled maturity dates at a call premium of $0.3 million. A note of $5.0 million bearing interest of 7.4% was scheduled to mature in March 2013, and a note of $2.2 million bearing interest of 7.5% was scheduled to mature in March 2014. We redeemed these notes using proceeds from the issuance of commercial paper.

In July 2003, we exercised our option to redeem $65.3 million of Medium-Term notes at a call premium of $2.4 million. We recorded this call premium as a regulatory asset and will amortize and collect in rates the call premium over the remaining life of the notes on the day they are retired, which is 10 to 20 years. These notes were scheduled to mature in 2013 and 2023 bearing interest rates ranging from 7.5% to 8.25%.

In October 2003, we repaid on its original due date a $30.0 million Medium-Term note with an interest rate of 5.90%; and we exercised an option to redeem before their scheduled maturity dates of October 2006 and October 2020, respectively, a $10.0 million Medium-Term note, at par, and a $2.0 million Medium-Term note, at a premium bearing interest at a rate of 6.0% and 6.85%, respectively. In December 2003, we exercised our option to redeem $92.8 million of Medium-Term notes at a call premium. These notes were scheduled to mature in 2005 and 2013 bearing interest rates from 6.55% to 7.2%.

Trust Preferred Securities In June 1997, we established AGL Capital Trust I (Trust I), a Delaware business trust, of which AGL Resources owns all the common voting securities. Trust I issued and sold $75.0 million principal amount of 8.17% capital securities (liquidation amount $1,000 per capital security) to certain initial investors. Trust I used the proceeds to purchase 8.17% Junior Subordinated Deferrable Interest Debentures.

Trust I capital securities are subject to mandatory redemption at the time of the repayment of the junior subordinated debentures on June 1, 2037, or the optional prepayment by us after May 31, 2007. We fully and unconditionally guarantee all Trust I's obligations for the capital securities.

In March 2001, we established AGL Capital Trust II (Trust II), a Delaware business trust, of which AGL Capital owns all the common voting securities. In May 2001, Trust II issued and sold $150.0 million principal amount of 8.00% capital securities (liquidation amount $25 per capital security). Trust II used the proceeds to purchase 8.00% Junior Subordinated Deferrable Interest Debentures. The proceeds from the issuance were used to refinance a portion of the existing short-term debt under the commercial paper program.

Trust II capital securities are subject to mandatory redemption at the time of the repayment of the junior subordinated debentures on May 15, 2041, or the optional prepayment by AGL Capital after May 21, 2006. We fully and unconditionally guarantee all Trust II's obligations for the capital securities.

Other Preferred Securities As of December 31, 2003, we had 10.0 million shares of authorized, unissued Class A Junior Participating Preferred Stock, no par value; and 10.0 million shares of authorized, unissued preferred stock, no par value.

Default Events

Our Credit Facility financial covenants and the Public Utility Holding Company Act of 1935, as amended (PUHCA) require us to maintain a ratio of total debt to total capitalization of no greater than 70.0%. Our debt instruments and other financial obligations include provisions that, if not complied with, could require early payment, additional collateral support or similar actions. Our most important default events include

- a maximum leverage ratio
- minimum net worth
- insolvency events and nonpayment of scheduled principal or interest payments
- acceleration of other financial obligations
- change of control provisions

We do not have any trigger events in our debt instruments that are tied to changes in our specified credit ratings or our stock price and have not entered into any transaction that requires us to issue equity based on credit ratings or other trigger events. We are currently in compliance with all existing debt provisions and covenants.

Shelf Registration

We currently have an active shelf registration statement for up to $750 million of various capital securities, with remaining capacity of approximately $383 million. On September 23, 2003, we filed a second shelf registration with the SEC for authority to increase our capacity to $1.0 billion of various capital securities.

> Note 8
Common Shareholders' Equity

Shareholder Rights Plan

On March 6, 1996, our Board of Directors adopted a Shareholder Rights Plan. The plan contains provisions to protect our shareholders in the event of unsolicited offers to acquire us or other takeover bids and practices that could impair the ability of the Board of Directors to represent shareholders' interests fully. As required by the Shareholder Rights Plan, the Board of Directors declared a dividend of one preferred share purchase right (a Right) for each outstanding share of our common stock, with distribution made to shareholders of record on March 22, 1996.

The Rights, which will expire March 6, 2006, are represented by and traded with our common stock. The Rights are not currently exercisable and do not become exercisable unless a triggering event occurs. One of the triggering events is the acquisition of 10% or more of our common stock by a person or group of affiliated or associated persons. Unless previously redeemed, upon the occurrence of one of the specified triggering events, each Right will entitle its holder to purchase one one-hundredth of a share of Class A Junior Participating Preferred Stock at a purchase price of $60. Each preferred share will have 100 votes, voting together with the common stock. Because of the nature of the preferred shares' dividend, liquidation and voting rights, one one-hundredth of a share of preferred stock is intended to have the value, rights and preferences of one share of common stock. As of December 31, 2003, 1.0 million shares of Class A Junior Participating Preferred Stock were reserved for issuance under that plan.

Equity Offering

On February 14, 2003, we completed our public offering of 6.4 million shares of common stock. We priced the offering at $22.00 per share and generated net proceeds of approximately $136.7 million, which we used to repay outstanding short-term debt and for general corporate purposes.

Common Share Activity

The following table provides details of our authorized, issued and outstanding common stock as of December 31, 2003 and our activity of common stock out of treasury under the RSP, the NSP, the LTIP, the LTSIP and the Directors Plan:

Shares in millions	Authorized	Issued	Treasury Shares	Outstanding
As of September 30, 2000	750.0	57.8	(3.8)	54.0
Fiscal 2001 activity	-	-	1.1	1.1
As of September 30, 2001	750.0	57.8	(2.7)	55.1
Transition period activity	-	-	0.5	0.5
As of December 31, 2001	750.0	57.8	(2.2)	55.6
Calendar 2002 activity	-	-	1.1	1.1
As of December 31, 2002	750.0	57.8	(1.1)	56.7
Calendar 2003 activity	-	6.7	1.1	7.8
As of December 31, 2003 (1)	**750.0**	**64.5**	**-**	**64.5**

(1) As of December 31, 2003, 8.9 million shares of common stock were reserved for issuance under ResourcesDIRECT™, the RSP, the NSP, the LTIP, the LTSIP and the Directors Plan.

Average Common Stock Issuance Price

The following table depicts the weighted average issuance price received as a result of our 6.4 million share common equity offering and the weighted average issuance price of shares out of treasury under ResourcesDIRECT™, our direct stock purchase and dividend reinvestment plan; the RSP; the LTSIP; the LTIP; and the Directors Plan:

All amounts on a per share basis	**Calendar 2003**	Calendar 2002	Transition Period	Fiscal 2001
Equity offering	**$22.00**	$ -	$-	$-
Issuance of authorized common shares	**28.66**	-	-	-
Issuance of treasury shares	**26.04**	23.32	21.98	22.65
Weighted average issuance price of common shares	**$22.79**	$23.32	$21.98	$22.65

Common Stock Dividends

Our common shareholders may receive common stock dividends when declared by our Board of Directors, which may be paid in cash, stock or other form of payment. In certain cases, our ability to pay common stock dividends to our common shareholders is limited by the following:

- satisfying our obligations under certain financing agreements including debt-to-capitalization and total shareholders' equity covenants
- satisfying our obligations to any preferred shareholders
- restrictions from the PUHCA on our payment of dividends out of capital or unearned surplus without prior permission from the SEC

Additionally, under Georgia law, common stock dividends are limited to our legally available assets and subject to the prior payment of common stock dividends on any outstanding shares of preferred stock and junior preferred stock. Also, our assets are restricted by Georgia law and are not legally available for paying dividends if

- we could not pay our debts as they become due in the usual course of business
- our total assets would be less than our total liabilities plus, subject to some exceptions, any amounts necessary to satisfy the preferential rights upon dissolution of shareholders whose preferential rights are superior to those of common shareholders receiving the common stock dividends

On April 16, 2003, we announced a 3.7% increase in our common stock dividend, raising the quarterly dividend from $0.27 per share to $0.28 per share which equates to an indicated annual dividend of $1.12 per share. This increase in our common stock dividend along with the shares issued in connection with our equity offering resulted in an approximately $10 million increase in dividends paid on our common shares.

> Note 9
Commitments and Contingencies

The following table illustrates our expected future contractual cash obligations as of December 31, 2003:

		Payments Due before December 31,			
In millions	Total	2004	2005 & 2006	2007 & 2008	2009 & Thereafter
Long-term debt (1)	$1,033.1	$77.0	$-	$-	$956.1
Pipeline charges, storage capacity and gas supply (2)	709.0	219.8	234.3	97.2	157.7
PRP costs (3)	404.3	81.6	162.0	160.7	-
Short-term debt	306.4	306.4	-	-	-
ERC (3)	83.0	40.3	22.8	3.8	16.1
Operating leases (4)	82.6	11.8	21.6	16.4	32.8
Communication/network service and maintenance	17.8	8.2	9.6	-	-
Pension Contribution (5)	15.0	15.0	-	-	-
Total	$2,651.2	$760.1	$450.3	$278.1	$1,162.7

(1) Includes $225.3 million of Trust Preferred Securities, 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.
(5) We calculate the amount of funding using an actuarial method called the projected unit credit cost method. However, it is not necessarily required, and we may fund lesser amounts in the future. We have not included expected contributions for years after 2004.

In January 2003, the FASB released FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). For many of the guarantees or indemnification agreements we issue, FIN 45 requires disclosure of the nature of the guarantee and the maximum potential amount of future payments that could be required of us as the guarantor. The table below illustrates our expected commercial commitments that are outstanding as of December 31, 2003 and meet the disclosure criteria required by FIN 45:

		Commitments Due before December 31,			
In millions	Total	2004	2005 & 2006	2007 & 2008	2009 & Thereafter
Guarantees (1) (2)	228.5	228.5	-	-	-
Standby letters of credit, performance/ surety bonds	7.9	7.9	-	-	-
Total other commercial commitments	$236.4	$236.4	$-	$-	$-

(1) $176.2 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 affiliate, SouthStar. We guarantee 70% of SouthStar's obligations to Southern Natural Gas Company and its affiliate South Georgia Natural Gas Company (together referred to as SONAT) under certain agreements between the parties up to a maximum of $7.0 million if SouthStar fails to make payment to SONAT. 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 $42.3 million, which represents our share of SouthStar's maximum credit support obligation to AGLC under its tariff.

Rental expense and sublease income

The following table illustrates our total rental lease expenses and sublease credits incurred for property and equipment:

In millions	**Calendar 2003**	Calendar 2002	Transition Period	Fiscal 2001
Rental expense (1)	**$21.7**	$20.0	$3.5	$17.7
Sublease income	**(0.3)**	(1.5)	(0.4)	(1.5)

(1) Our rental lease commitments for future years are as follows: $11.8 million in 2004; $11.2 million in 2005; $10.4 million in 2006; $8.4 million in 2007; and $8.0 million in 2008.

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.

On July 1, 2003, the city of Augusta, Georgia served AGLC with a complaint that was filed in the Superior Court of Richmond County, Georgia. The City of Augusta's allegations include fraud and deceit and damages to realty. The allegations arise from negotiations between the city and AGLC regarding the environmental cleanup obligations connected with AGLC's former MGP operations in Augusta. The city of Augusta seeks relief in the form of damages, including an amount to be determined by a jury for the alleged fraud and deceit, together with attorney fees and punitive damages. We believe the claims asserted in this complaint are without merit, and we have remained in active settlement negotiations with the city of Augusta. For more information about MGPs and our environmental cleanup obligations, please see the "Environmental Response Costs" section of Note 4, "Regulatory Assets and Liabilities."

> Note 10
Fair Value of Financial Instruments

The following table shows the carrying amounts and fair values of financial instruments included in our consolidated balance sheets:

In millions	Carrying Amount	Estimated Fair Value
As of December 31, 2003		
Long-term debt including current portion	**$807.8**	**$863.8**
Capital securities	**225.3**	**302.1**
As of December 31, 2002		
Long-term debt including current portion	797.0	884.4
Capital securities	227.2	263.4

The estimated fair values are determined based on the following:

- Long-term debt - interest rates that are currently available for issuance of debt with similar terms and remaining maturities.
- Capital securities - quoted market price and dividend rates for preferred stock with similar terms.

Considerable judgment is required to develop the fair value estimates; therefore, the values are not necessarily indicative of the amounts that could be realized in a current market exchange. The fair value estimates are based on information available to management as of December 31, 2003. We are not aware of any subsequent factors that would significantly affect the estimated fair value amounts. For more information about the fair values of our interest rate swaps, see Note 3, "Risk Management."

> Note 11
Income Taxes

We have two categories of income taxes in our statements of consolidated income: current and deferred. Current income tax expense consists of federal and state income tax less applicable tax credits related to the current year. Deferred income tax expense generally is equal to the changes in the deferred income tax liability and regulatory tax liability during the year.

Investment Tax Credits

Deferred investment tax credits associated with distribution operations are included as a regulatory liability in our consolidated balance sheets (see Note 4). These investment tax credits are being amortized over the estimated life of the related properties as credits to income in accordance with regulatory treatment. We reduce income tax expense in our statements of consolidated income for the investment tax credits and other tax credits associated with our nonregulated subsidiaries.

Accumulated Deferred Income Tax Assets and Liabilities

We report some of our assets and liabilities differently for financial accounting purposes than we do for income tax purposes. The tax effects of the differences in those items are reported as deferred income tax assets or liabilities in our consolidated balance sheets. The assets and liabilities are measured utilizing income tax rates that are currently in effect. Because of the regulated nature of the utility's business, a regulatory tax liability has been recorded in accordance with SFAS No. 109, "Accounting for Income Taxes" (SFAS 109). The regulatory tax liability is being amortized over approximately 30 years (see Note 4).

The deferred tax asset related to the additional pension liability of $30.8 million recorded in 2002 has been reduced to $26.6 million in 2003, a net decrease of $4.2 million. This decrease is comprised of a $5.5 million decrease for the reduction of the additional pension liability (see Note 5), offset by a $1.3 million increase for an adjustment to the 2002 ending balance due to a change in the effective tax rate (as required by SFAS 109).

Components of income tax expense shown in the statements of consolidated income are as follows:

In millions	**Calendar 2003**	Calendar 2002	Transition Period	Fiscal 2001
Included in expenses:				
Current income taxes				
Federal	**$19.8**	($18.4)	$11.2	$39.5
State	**13.2**	(4.2)	(10.6)	5.0
Deferred income taxes				
Federal	**51.8**	78.7	1.2	5.4
State	**3.3**	3.2	12.1	1.3
Amortization of investment tax credits	**(1.3)**	(1.3)	(0.3)	(1.3)
Total	**$86.8**	$58.0	$13.6	$49.9

Reconciliation between the statutory federal income tax rate and the effective rate is as follows:

	Calendar 2003		Calendar 2002		Transition Period		Fiscal 2001	
Dollars in millions	Amount	% of Pretax Income	Amount	% of Pretax Income	Amount	% of Pretax Income	Amount	% of Pretax Income
Computed tax expense	**$77.9**	**35.0%**	$56.4	35.0%	$13.5	35.0%	$48.6	35.0%
State income tax, net of federal income tax benefit	**8.4**	**3.8**	3.9	2.4	0.6	1.4	2.5	1.9
Amortization of investment tax credits	**(1.3)**	**(0.6)**	(1.3)	(0.8)	(0.3)	(0.8)	(1.3)	(0.9)
Flexible dividend deduction	**(1.4)**	**(0.6)**	(1.4)	(0.9)	-	-	-	-
Other-net	**3.2**	**1.4**	0.4	0.3	(0.2)	(0.3)	0.1	-
Total income tax expense	**$86.8**	**39.0%**	$58.0	36.0%	$13.6	35.3%	$49.9	36.0%

Components that give rise to the net accumulated deferred income tax liability are as follows:

	As of:	
In millions	**Dec. 31, 2003**	Dec.31, 2002
Accumulated deferred income tax liabilities		
Property-accelerated depreciation and other property-related items	**$293.8**	$272.2
Other	**125.6**	94.4
Total accumulated deferred income tax liabilities	**419.4**	366.6
Accumulated deferred income tax assets		
Deferred investment tax credits	**7.3**	7.8
Deferred pension additional minimum liability	**26.6**	30.8
Other	**9.2**	8.0
Total accumulated deferred income tax assets	**43.1**	46.6
Net accumulated deferred income tax liability	**$376.3**	$320.0

> Note 12
Related Party Transactions

We recognized revenue and had accounts receivable from our affiliate, SouthStar, of the following:

In millions	**Calendar 2003**	Calendar 2002	Transition Period	Fiscal 2001
Recognized revenue	**$168.8**	$171.3	$41.1	$185.9
Accounts receivable	**10.9**	-	-	1.7

Utilipro Inc. (Utilipro), our formerly owned billing subsidiary, recognized revenue of $7.9 million on services provided to SouthStar during fiscal 2001.

> Note 13
Equity Investments

We apply the equity method of accounting for our investments in SouthStar and US Propane. We do not provide additional financial disclosures on US Propane, as its results of operations and financial condition are not material to our financial results. However, as SouthStar's results of operations and financial condition are material to our financial results, we present below the summarized amounts for 100% of SouthStar.

These results are not comparable with our earnings or losses from SouthStar, which we report as other income (loss) in our statements of consolidated income, as those amounts are reported based on our ownership percentage during each year. On February 18, 2003, we acquired Dynegy's 20% ownership interest in SouthStar, increasing our non controlling ownership percentage from 50% to 70%; however, as discussed below SouthStar's earnings were allocated 80% to us in 2003, less income that was allocated to Dynegy prior to February 18, 2003. In 2002, the transition period and fiscal 2001, SouthStar's earnings were allocated 50% to us. SouthStar's net income from continuing operations and net income are equal because as a partnership, SouthStar does not incur income tax expenses.

	As of:	
In millions	**Dec. 31, 2003**	Dec. 31, 2002
Balance Sheet		
Current assets	**$173.9**	$165.1
Noncurrent assets	**1.9**	0.9
Current liabilities	**75.0**	79.6
Noncurrent liabilities	**-**	-

In millions	**Calendar 2003**	Calendar 2002	Transition Period (Unaudited)	Fiscal 2001 (Unaudited)
Income Statement				
Revenues	**$745.6**	$629.6	$172.1	$815.3
Operating margin	**124.0**	115.1	35.2	118.7
Operating income	**63.0**	40.9	21.0	28.7
Net income from continuing operations	**63.3**	41.5	20.7	23.7

SouthStar's operating policy contains a provision for the disproportionate sharing of earnings with our partner in SouthStar, Piedmont, when SouthStar's annual earnings before taxes exceed a certain threshold. The threshold is calculated each year based on a cumulative and annual return on contributed capital. SouthStar's operating policy requires that earnings above the threshold be allocated at various percentages based on actual margin generated in the four defined service areas of the operating policy, and distributed annually to each owner as a mandatory distribution. Disproportionate sharing is only applicable to our original 50% financial interest in SouthStar.

On December 31, 2003, the owners resolved the disproportionate sharing of earnings with an agreement that provides for SouthStar's 2003 earnings to be allocated 80% to our subsidiary and 20% to Piedmont, less income allocable to Dynegy prior to February 18, 2003. The agreement resulted in our recognition of $5.9 million of equity earnings for disproportionate sharing for the 12 months ended December 31, 2003. The agreement also provided for a cash distribution of $40 million to the owners on December 31, 2003, which allocated $34 million to our subsidiary and $6 million to Piedmont. The agreement further resolved all issues related to the allocation of income for all fiscal years prior to 2003 by disregarding disproportionate sharing issues for those prior years and allocating earnings for such years based on the current owners' respective interests for such prior fiscal years.

> Note 14
Segment Information

Our business is organized into three operating segments:

- Distribution operations consists of AGLC, VNG and CGC.
- Wholesale services consists primarily of Sequent.
- Energy investments consists primarily of SouthStar, AGL Networks and US Propane.

We treat corporate, our fourth segment, as a nonoperating business segment, and it includes AGL Resources Inc., AGL Services Company, nonregulated financing and captive insurance subsidiaries, and the effect of intercompany eliminations. We eliminated intersegment sales for the three and nine months ended September 30, 2003 and 2002 from our statements of consolidated income.

Management evaluates 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 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.

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 earnings before income taxes and net income are presented below:

In millions	**Calendar 2003**	Calendar 2002	Transition Period	Fiscal 2001
Operating income	**$258.3**	$216.5	$57.4	$218.9
Other income	**39.8**	30.5	4.9	17.3
EBIT	**298.1**	247.0	62.3	236.2
Interest expense	**75.6**	86.0	23.8	97.4
Earnings before income taxes	**222.5**	161.0	38.5	138.8
Income taxes	**86.8**	58.0	13.6	49.9
Income before cumulative effect of change in accounting principle	**135.7**	103.0	24.9	88.9
Cumulative effect of change in accounting principle	**(7.8)**	-	-	-
Net income	**$127.9**	$103.0	$24.9	$88.9

In millions	Distribution Operations	Wholesale Services	Energy Investments	Corporate and Intersegment Eliminations	Consolidated AGL Resources
	As of or for the 12 months ended December 31, 2003				
Operating revenues (1)	**$935.9**	**$41.2**	**$6.5**	**$0.1**	**$983.7**
Depreciation and amortization	**80.9**	**0.1**	**0.9**	**9.5**	**91.4**
Gain (loss) on sale of Caroline Street campus (2)	**21.5**	**-**	**-**	**(5.6)**	**15.9**
Operating income (loss)	**253.4**	**19.9**	**(4.9)**	**(10.1)**	**258.3**
Interest income	**0.1**	**-**	**0.2**	**0.1**	**0.4**
Donation to private foundation	**(8.0)**	**-**	**-**	**-**	**(8.0)**
Earnings in equity interests	**-**	**-**	**47.6**	**-**	**47.6**
Other income (loss)	**1.3**	**(0.3)**	**0.2**	**(1.4)**	**(0.2)**
Total other income (loss)	**(6.6)**	**(0.3)**	**48.0**	**(1.3)**	**39.8**
EBIT	**$246.8**	**$19.6**	**$43.1**	**($11.4)**	**$298.1**
Identifiable assets	**$3,325.0**	**$460.0**	**$89.6**	**$1.9**	**$3,876.5**
Investment in joint ventures	**-**	**-**	**101.3**	**-**	**101.3**
Total assets	**$3,325.0**	**$460.0**	**$190.9**	**$1.9**	**$3,977.8**
Capital expenditures	**$125.8**	**$1.7**	**$8.2**	**$22.7**	**$158.4**

In millions	Distribution Operations	Wholesale Services	Energy Investments	Corporate and Intersegment Eliminations	Consolidated AGL Resources
	As of or for the 12 months ended December 31, 2002				
Operating revenues (1)	$852.4	$23.0	$2.0	$(0.2)	$877.2
Depreciation and amortization	82.0	-	0.3	6.8	89.1
Operating income (loss)	222.5	9.1	(6.5)	(8.6)	216.5
Interest income	0.5	-	0.1	-	0.6
Earnings in equity interests	-	-	27.2	-	27.2
Other income (loss)	1.4	-	2.8	(1.5)	2.7
Total other income (loss)	1.9	-	30.1	(1.5)	30.5
EBIT	$224.4	$9.1	$23.6	($10.1)	$247.0
Identifiable assets	$3,149.8	$364.3	$107.2	$45.9	$3,667.2
Investment in joint ventures	-	-	74.8	-	74.8
Total assets	$3,149.8	$364.3	$182.0	$45.9	$3,742.0
Capital expenditures	$128.1	$0.8	$28.6	$29.5	$187.0

In millions	Distribution Operations	Wholesale Services	Energy Investments	Corporate and Intersegment Eliminations	Consolidated AGL Resources
	As of or for the 3 months ended December 31, 2001				
Operating revenues (1)	$197.2	$6.5	$0.4	$(0.3)	$203.8
Depreciation and amortization	21.2	-	-	2.0	23.2
Operating income (loss)	59.7	3.4	(1.7)	(4.0)	57.4
Interest income	0.2	-	-	-	0.2
Earnings in equity interests	-	-	5.2	-	5.2
Other income (loss)	(0.1)	-	0.1	(0.5)	(0.5)
Total other income (loss)	0.1	-	5.3	(0.5)	4.9
EBIT	$59.8	$3.4	$3.6	($4.5)	$62.3
Identifiable assets	$3,198.9	$115.4	$56.0	$9.1	$3,379.4
Investment in joint ventures	-	-	74.9	-	74.9
Total assets	$3,198.9	$115.4	$130.9	$9.1	$3,454.3
Capital expenditures	$35.8	$0.2	$11.9	$4.0	$51.9

	As of or for the 12 months ended September 30, 2001				
In millions	Distribution Operations	Wholesale Services	Energy Investments	Corporate and Intersegment Eliminations	Consolidated AGL Resources
Operating revenues (1)	$919.6	$11.6	$9.2	$5.8	$946.2
Depreciation and amortization	90.4	-	0.9	8.7	100.0
Operating income (loss)	210.8	5.3	(4.9)	7.7	218.9
Interest income	0.6	-	0.8	(0.5)	0.9
Earnings in equity interests	-	-	13.8	-	13.8
Other income (loss)	1.8	(2.2)	0.7	(8.6)	(8.3)
Gain on sale of Utilipro	-	-	10.9	-	10.9
Total other income (loss)	2.4	(2.2)	26.2	(9.1)	17.3
EBIT	$213.2	$3.1	$21.3	($1.4)	$236.2
Identifiable assets	$3,319.8	$42.0	$33.5	($96.9)	$3,298.4
Investment in joint ventures	-	-	69.7	-	69.7
Total assets	$3,319.8	$42.0	$103.2	($96.9)	$3,368.1
Capital expenditures	$144.2	$-	$1.2	$10.3	$155.7

(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:

In millions	Third-Party Gross Revenues	Intersegment Revenues	Total Gross Revenues
Calendar 2003	$3,298.2	$352.7	$3,650.9
Calendar 2002	1,639.2	130.6	1,769.8
Transition period	128.4	20.0	148.4
Fiscal 2001	125.2	42.6	167.8

(2) The gain before income taxes of $15.9 million on the sale of our Caroline Street campus was recorded as operating income (loss) in two of our segments. A gain of $21.5 million on the sale of the land was recorded in distribution operations, and a write-off of ($5.6) million on the buildings and their contents was recorded in our corporate segment.

> Note 15
Quarterly Financial Data (Unaudited)

Our quarterly financial data for 2003 and 2002 are summarized below. The variance in our quarterly earnings is the result of the seasonal nature of our primary business.

Calendar 2003	Three months ended				
In millions, except per share amounts	March 31	June 30	Sept. 30	Dec. 31	Total
Operating revenues	$352.5	$186.6	$166.3	$278.3	$983.7
Operating income	101.5	40.9	58.2	57.7	258.3
Net income	51.8	18.9	22.2	35.0	127.9
Basic earnings per share	0.86	0.30	0.35	0.54	2.03
Diluted earnings per share	0.85	0.29	0.34	0.54	2.01

Calendar 2002	Three months ended				
In millions, except per share amounts	March 31	June 30	Sept. 30	Dec. 31	Total
Operating revenues	$271.9	$161.2	$193.0	$251.1	$877.2
Operating income	74.0	41.9	38.4	62.2	216.5
Net income	50.1	12.3	9.4	31.2	103.0
Basic earnings per share	0.90	0.22	0.17	0.55	1.84
Diluted earnings per share	0.89	0.22	0.17	0.55	1.82

Our basic and diluted earnings per common share are calculated based on the weighted average number of common shares and common share equivalents outstanding during the quarter. Those totals differ from the basic and diluted earnings per share, as shown on the statements of consolidated income, which are based on the weighted average number of common shares and common share equivalents outstanding during the entire year.

> Note 16
Financial Information for the Period of October 1, 2000 to December 31, 2000 (Unaudited)

We changed our fiscal year end from September 30 to December 31, effective October 1, 2001. The financial statements, as of and for the three-month transition period ended December 31, 2001, are included in this Form 10-K. All references to the three-month period from October 1, 2000 to December 31, 2000 are unaudited. The following financial data are presented to illustrate the results of operations and earnings per share information for the three-month period ended December 31, 2000:

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED STATEMENTS OF CONSOLIDATED INCOME
FOR THE THREE MONTHS ENDED
DECEMBER 31, 2000
(UNAUDITED)

In millions, except per share amounts	
Operating revenues	$295.4
Operating expenses	
Cost of gas	130.8
Operation and maintenance	72.2
Depreciation and amortization	26.1
Taxes other than income	10.4
Total operating expenses	239.5
Operating income	55.9
Other income	4.6
Interest expense	(24.7)
Earnings before income taxes	35.8
Income taxes	13.3
Net income	$22.5
Earnings per common share	
Basic	$0.41
Diluted	$0.41
Weighted average number of common shares outstanding	
Basic	54.1
Diluted	54.5

> Note 17
Subsequent Event

On January 20, 2004, we closed on an agreement to sell our general and limited partnership interests in Heritage. The agreement involved our subsidiary, AGL Propane Services, and three other nonaffiliated utility partners. The aggregate transaction was valued at $130 million. Upon closing, we received $29 million for our portion of the transaction. We do not expect to recognize a material gain or loss on the transaction.

Report of Independent Auditor

To the Board of Directors and Shareholders of AGL Resources Inc.:

In our opinion, based on our audit and the report of other auditors, the accompanying consolidated balance sheets and the related statements of consolidated income, common shareholders' equity, and cash flows present fairly, in all material respects, the financial position of AGL Resources Inc. and subsidiaries at December 31, 2003, and the results of its operations and its cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, based on our audit and the report of other auditors, the financial statement schedule as of and for the year ended December 31, 2003 listed in the index appearing under Item 15(a)(2), presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audit. We did not audit the financial statements of SouthStar Energy Services LLC, a joint venture in which a subsidiary of AGL Resources has a non-controlling 70% financial interest, which statements reflect total assets of $175.9 million as of December 31, 2003, and total revenues of $745.6 million, for the year then ended. Those statements were audited by other auditors whose report thereon has been furnished to us, and our opinion expressed herein, insofar as it relates to the amounts included for SouthStar Energy Services LLC., is based solely on the report of the other auditors. We conducted our audit of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit and the report of other auditors provide a reasonable basis for our opinion.

As discussed in Note 2 to the consolidated financial statements, Effective January 1, 2003, AGL Resources Inc. and subsidiaries adopted EITF No. 02-03, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.* As discussed in Note 2 to the consolidated financial statements, effective January 1, 2003, AGL Resources Inc. and subsidiaries adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Atlanta, Georgia
January 29, 2004

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of
Directors of AGL Resources Inc.:

We have audited the accompanying consolidated balance sheets of AGL Resources Inc. and subsidiaries as of December 31, 2002 and the related statements of consolidated income, common shareholders' equity, and cash flows for the years ended December 31, 2002 and September 30, 2001 and the three months ended December 31, 2001. Our audits also included the financial statement schedule of the Company, listed in Item 15(a)2 for the years ended December 31, 2002 and September 30, 2001 and for the three months ended December 31, 2001. These financial statements and the financial statement schedule are the responsibility of AGL Resources' management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of AGL Resources Inc. and subsidiaries as of December 31, 2002 and the results of its operations and its cash flows for the years ended December 31, 2002 and September 30, 2001 and the three months ended December 31, 2001, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, such financial statement schedule for the years ended December 31, 2002 and September 30, 2001 and for the three months ended December 31, 2001 when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, in 2002 AGL Resources Inc. and subsidiaries adopted the June 2002 consensus of EITF Issue No. 02-03, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," that required all mark-to-market gains and losses on energy-trading contracts to be shown net in the income statements whether or not settled physically.

/s/ Deloitte & Touche LLP

Atlanta, Georgia
January 27, 2003

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

ITEM 9A. 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 Annual 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 III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required by this item with respect to directors is set forth under the caption "Election of Directors" in the Proxy Statement and is incorporated here by reference. The information required by this item with respect to the executive officers is, pursuant to Instruction 3 of Item 401(b) of Regulation S-K and General Instruction G (3) of Form 10-K, set forth at Part I, Item 4.(A) of this report under the caption "Executive Officers of the Registrant."

Code of Ethics We have adopted a code of ethics, which applies to our chief executive officer and our senior financial officers. Our code of ethics is posted on our website at www.aglresources.com under the headings "Corporate Governance – Highlights." We will also provide a copy of the code of ethics to shareholders upon request. Any amendments to or waivers from any provision of our code of ethics will be disclosed by posting such information on our website.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item is set forth under the caption "Executive Compensation" in the Proxy Statement and is incorporated by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Equity Compensation Plan Information

The following table provides information as of December 31, 2003 with respect to the shares of our Common Stock that may be issued under our existing equity compensation plans:

Plan Category	Number of Securities To Be Issued upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (c)
Equity compensation plans approved by security holders (1)	3,089,032	$22.21	3,792,008
Equity compensation plans not approved by security holders (2)	421,938	22.47	115,322
Total	3,510,970	$22.25	3,907,330

(1) These plans consist of the AGL Resources Inc. Long-Term Stock Incentive Plan of 1990, the AGL Resources Inc. Long-Term Incentive Plan (LTIP) (1999) and the AGL Resources Inc. Amended and Restated 1996 Non-Employee Directors Equity Compensation Plan. As of January 1 of each year, the number of shares issuable under the LTIP is increased by an amount equal to 2% of the shares outstanding on the immediately preceding December 31.

(2) The Company sponsors the Officer Incentive Plan under which equity securities are eligible for transfer. This plan is considered an "open market" plan that does not require shareholder approval.

The remainder of the information required by this item is set forth under the caption "Security Ownership of Management" in the Proxy Statement and is incorporated by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by this item is set forth under the captions "Governance of the Company – Director Independence" and "Other Matters Involving Directors and Executive Officers" in the Proxy Statement and is incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this item is set forth under the caption "General Information" in the Proxy Statement and is incorporated by reference.

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PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) Documents Filed as Part of This Report:

1. Financial Statements
Included under Item 8 are the following financial statements:

- Consolidated Balance Sheets as of December 31, 2003 and December 31, 2002.
- Statements of Consolidated Income for the years ended December 31, 2003 and December 31, 2002, the transition period ended December 31, 2001 and the fiscal year ended September 30, 2001.
- Statements of Consolidated Common Stockholders' Equity for the years ended December 31, 2003 and December 31, 2002, the transition period ended December 31, 2001 and the fiscal year ended September 30, 2001.
- Statements of Consolidated Cash Flows for the years ended December 31, 2003 and December 31, 2002, the transition period ended December 31, 2001 and the fiscal year ended September 30, 2001.
- Notes to Consolidated Financial Statements.
- Independent Auditors' Report.

2. Supplemental Consolidated Financial Schedules for Each of the Three Years in the Period Ended December 31, 2003, December 31, 2002, September 30, 2001 and the three months ended December 31, 2001

- Financial Statement Schedule II. Valuation and Qualifying Account-Allowance for Uncollectible Accounts.
- Schedules other than those referred to above are omitted and are not applicable or not required, or the required information is shown in the financial statements or notes thereto.

3. Exhibits

Where an exhibit is filed by incorporation by reference to a previously filed registration statement or report, such registration statement or report is identified in parentheses.

1.1	Underwriting Agreement dated February 11, 2003 by and among AGL Resources Inc. and the Underwriters named therein. (Exhibit 1.1, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2002).
2.1	Stock Purchase Agreement dated May 8, 2000 by and between AGL Resources Inc. and Consolidated Natural Gas Company, Virginia Natural Gas, Inc. and Dominion Resources, Inc. (Exhibit 2.1, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2000).
2.2	First Amendment to Stock Purchase Agreement dated October 1, 2000 by and between AGL Resources Inc. and Consolidated Natural Gas Company, Virginia Natural Gas, Inc. and Dominion Resources, Inc. (Exhibit 2.2, AGL Resources Inc. Current Report on Form 8-K dated October 18, 2000).
3.1	Amended and Restated Articles of Incorporation filed January 5, 1996, with the Secretary of State of the State of Georgia (Exhibit B, Proxy Statement and Prospectus filed as a part of Amendment No. 1 to Registration Statement on Form S-4, No. 33-99826).
3.2	Bylaws, as amended on October 29, 2003.
4.1	Specimen form of Common Stock certificate (Exhibit 4.1, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 1999).
4.2.a	Specimen form of Right certificate (Exhibit 1, AGL Resources Inc. Form 8-K filed March 6, 1996).
4.3	Indenture, dated as of December 1, 1989, between Atlanta Gas Light Company and Bankers Trust Company, as Trustee (Exhibit 4(a), Atlanta Gas Light Company Registration Statement on Form S-3, No. 33-32274).
4.4	First Supplemental Indenture dated as of March 16, 1992, between Atlanta Gas Light Company and NationsBank of Georgia, National Association, as Successor Trustee (Exhibit 4(a), Atlanta Gas Light Company Registration Statement on Form S-3, No. 33-46419).
10.1	Executive Compensation Plans and Arrangements.
10.1.a	AGL Resources Inc. Long-Term Incentive Plan (1999), as amended and restated as of January 1, 2002 (Exhibit 99.2, AGL Resources Inc. Form 10-Q for the quarter ended March 31, 2002).
10.1.b	AGL Resources Inc. Long-Term Stock Incentive Plan of 1990 (Exhibit 10(ii), Atlanta Gas Light Company Form 10-K for the fiscal year ended September 30, 1991).
10.1.c	First Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan of 1990 (Exhibit B to the Atlanta Gas Light Company Proxy Statement for the Annual Meeting of Shareholders held February 5, 1993).
10.1.d	Second Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan of 1990 (Exhibit 10.1.d, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 1997).
10.1.e	Third Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan of 1990 (Exhibit C to the Proxy Statement and Prospectus filed as a part of Amendment No. 1 to Registration Statement on Form S-4, No. 33-99826).

10.1.f	Fourth Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan of 1990 (Exhibit 10.1.f, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 1997).
10.1.g	Fifth Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan of 1990 (Exhibit 10.1.g, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 1997).
10.1.h	Sixth Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan of 1990 (Exhibit 10.1.a, AGL Resources Inc. Form 10-Q for the quarter ended March 31, 1998).
10.1.i	Seventh Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan of 1990 (Exhibit 10.1, AGL Resources Inc. Form 10-Q for the quarter ended December 31, 1998).
10.1.j	Eighth Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan of 1990 (Exhibit 10.1, AGL Resources Inc. Form 10-Q for the quarter ended March 31, 2000).
10.1.k	Ninth Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan 1990 (Exhibit 10.6, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2002).
10.1.l	AGL Resources Inc. Nonqualified Savings Plan as amended and restated as of January 1, 2001 (Exhibit 10.1.n, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 2001).
10.1.m	First Amendment to the AGL Resources Inc. Nonqualified Savings Plan (Exhibit 10.3, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2002).
10.1.n	AGL Resources Inc. Amended and Restated 1996 Non-Employee Directors Equity Compensation Plan (Exhibit 10.1, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2002).
10.1.o	First Amendment to the AGL Resources Inc. Amended and Restated 1996 Non-Employee Directors Equity Compensation Plan. (Exhibit 10.1.o, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2002).
10.1.p	AGL Resources Inc. 1998 Common Stock Equivalent Plan for Non-Employee Directors (Exhibit 10.1.b, AGL Resources Inc. Form 10-Q for the quarter ended December 31, 1997).
10.1.q	First Amendment to the AGL Resources Inc. 1998 Common Stock Equivalent Plan for Non-Employee Directors (Exhibit 10.5, AGL Resources Inc. Form 10-Q for the quarter ended March 31, 2000).
10.1.r	Second Amendment to the AGL Resources Inc. 1998 Common Stock Equivalent Plan for Non-Employee Directors (Exhibit 10.4, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2002).
10.1.s	Third Amendment to the AGL Resources Inc. 1998 Common Stock Equivalent Plan for Non-Employee Directors (Exhibit 10.5, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2002).
10.1.t	AGL Resources Inc. Officer Incentive Plan (Exhibit 10.2, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2001).
10.1.u	Form of AGL Resources Inc. Executive Post Employment Medical Benefit Plan (Exhibit 10.1.d, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2003).
10.1.v	AGL Resources Inc. Executive Performance Incentive Plan dated February 2, 2002 (Exhibit 99.1, AGL Resources Inc. Form 10-Q for the quarter ended March 31, 2002).

10.1.w	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 Kevin P. Madden.
10.1.x	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 Richard T. O'Brien.
10.1.y	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 Paula G. Rosput.
10.1.z	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 Paul R. Shlanta.
10.2	Guaranty Agreement, effective November 30, 2003, by and between Atlanta Gas Light Company and AGL Resources Inc. (Exhibit 10.3, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2003).
10.3	Form of Commercial Paper Dealer Agreement between AGL Capital Corporation, as Issuer, AGL Resources Inc., as Guarantor, and the Dealers named therein, dated September 25, 2000. (Exhibit 10.79, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 2000).
10.4	Guarantee of AGL Resources Inc. dated October 5, 2000, of payments on promissory notes issued by AGL Capital Corporation (AGLCC) pursuant to the Issuing and Paying Agency Agreement dated September 25, 2000, between AGLCC and The Bank of New York. (Exhibit 10.80, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 2000).
10.5	Issuing and Paying Agency Agreement dated September 25, 2000, between AGL Capital Corporation and The Bank of New York. (Exhibit 10.81, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 2000).
10.6	Master Management Services Agreement dated April 24, 2000, by and between Atlanta Gas Light Company and Environmental ThermoRetec Consulting Corporation. (Exhibit 10.1, AGL Resources Inc. 10-Q for the quarter ended June 30, 2000.) (Confidential treatment pursuant to 17 CFR Sections 200.80 (b) and 240.24b-2 has been granted regarding certain portions of this exhibit, which portions have been filed separately with the Commission.) (Exhibit 10.82, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 2000).
10.7	Amended and Restated Master Environmental Management Services Agreement dated July 25, 2002 by and between Atlanta Gas Light Company and The RETEC Group, Inc. (Exhibit 10.2, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2003). (Confidential treatment pursuant to 17 CFR Sections 200.80 (b) and 240.24-b has been granted regarding certain portions of this exhibit, which portions have been filed separately with the Commission).
10.8	364 Day Credit Agreement with a one year term-out option dated June 16, 2003, by and between AGL Resources Inc., as Guarantor, AGL Capital Corporation, as Borrower, and the Lenders named therein (Exhibit 10.4, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2003).
10.9	Guarantee dated June 16, 2003, by and between AGL Resources Inc., the Guarantor, and SunTrust Bank, as Administrative Agent for the Lenders named in the 364 Day Credit Agreement with a one year term-out option, dated June 16, 2003 by and between AGL Capital Corporation, as Borrower and the Lenders named therein (Exhibit 10.5, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2003).

10.10	Three Year Credit Agreement dated August 8, 2002, by and between AGL Resources Inc., as Guarantor, AGL Capital Corporation, as Borrower, and the Lenders named therein (Exhibit 99.2, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2002).
10.11	Guarantee dated August 8, 2002, by and between AGL Resources Inc., the Guarantor, and SunTrust Bank, as Administrative Agent for the Lenders named in the Three Year Credit Agreement dated August 8, 2002 by and between AGL Capital Corporation, as Borrower and the Lenders named therein (Exhibit 99.4, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2002).
12	Statements of reasonable computation of ratios.
21	Subsidiaries of AGL Resources Inc.
23.1	Consent of PricewaterhouseCoopers LLP
23.2	Consent of Deloitte & Touche LLP
23.3	Consent of Ernst & Young LLP
24	Powers of Attorney (included with Signature Page hereto).
31	Rule 13a-14(a)/15d-14(a) Certifications
32	Section 1350 Certifications

(b) **Reports on Form 8-K**

- On October 30, 2003, we furnished a Current Report on Form 8-K dated October 30, 2003, containing "Item 12 – Results of Operation and Financial Condition."
- On November 7, 2003, we furnished a Current Report on Form 8-K dated November 7, 2003, containing "Item 9 - Regulation FD Disclosure."
- On November 17, 2003, we furnished a Current Report on Form 8-K dated November 17, 2003, containing "Item 9 - Regulation FD Disclosure."
- On November 18, 2003, we furnished a Current Report on Form 8-K dated November 17, 2003, containing "Item 9 - Regulation FD Disclosure."

(c) **For a list of our exhibits, see Item 15(a).**

(d) Financial Statements for SouthStar Energy Services LLC for the three years ended December 31, 2003, 2002 and 2001 and Report of Independent Auditors, which are included pursuant to Rule 3.09 of Regulation S-X.

REPORT OF INDENDENT AUDITORS

The Executive Committee and Members
SouthStar Energy Services LLC

We have audited the balance sheets of SouthStar Energy Services LLC as of December 31, 2003 and 2002, and the related statements of income, changes in members' capital, and cash flows for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of SouthStar Energy Services LLC at December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States.

/s/ Ernst & Young LLP

Atlanta, Georgia
January 21, 2004

SouthStar Energy Services LLC

Balance Sheets

	December 31 2003	December 31 2002
	(In Thousands)	
Assets		
Current assets:		
Cash and cash equivalents	**$7,639**	$6,906
Restricted cash	**3,654**	8,484
Accounts receivable:		
Trade accounts receivable	**64,532**	71,913
Unbilled revenue	**70,539**	55,941
Allowance for doubtful accounts	**(11,231)**	(14,945)
	123,840	112,909
Inventories	**29,108**	35,799
Financial instruments	**4,541**	–
Prepaid gas and expenses	**4,830**	708
Other current assets	**300**	244
Total current assets	**173,912**	165,050
Property and equipment:		
Office equipment	**54**	27
Furniture and fixtures	**254**	187
Software	**2,250**	500
Leasehold improvements	**192**	81
	2,750	795
Less accumulated depreciation	**(808)**	(580)
Net property and equipment	**1,942**	215
Intangibles, net of accumulated amortization of $5,493 and $4,818 at December 31, 2003 and 2002, respectively	**–**	675
Total assets	**$175,854**	$165,940
Liabilities and Members' capital		
Current liabilities:		
Accounts payable	**$6,204**	$15,893
Revolving line of credit	**5,169**	–
Accrued gas costs	**51,844**	43,666
Customer deposits	**6,095**	11,189
Financial instruments	**–**	3,744
Accrued compensation	**2,213**	1,810
Other accrued expenses	**3,522**	3,290
Total current liabilities	**75,047**	79,592
Total liabilities	**75,047**	79,592
Members' capital	**99,622**	87,918
Accumulated other comprehensive income (loss)	**1,185**	(1,570)
Total Members' capital	**100,807**	86,348
Total liabilities and Members' capital	**$175,854**	$165,940

See accompanying notes.

SouthStar Energy Services LLC

Statements of Income

	Year ended December 31		
	2003	**2002**	**2001**
	(In Thousands)		
Revenues	**$745,599**	$629,615	$715,388
Cost of sales	**621,591**	514,516	621,256
Gross margin	**124,008**	115,099	94,132
Operating expenses:			
Selling, general and administrative	**59,895**	72,231	73,033
Depreciation and amortization	**1,147**	1,964	1,281
	61,042	74,195	74,314
Operating income	**62,966**	40,904	19,818
Miscellaneous income (expense):			
Interest expense	**(343)**	(306)	(2,860)
Interest income	**475**	788	143
Other, net	**215**	128	(297)
	347	610	(3,014)
Net income	**63,313**	41,514	16,804
Proforma provision for income taxes (unaudited)	**25,325**	16,606	6,722
Proforma net income (unaudited)	**$ 37,988**	$ 24,908	$ 10,082

See accompanying notes.

SouthStar Energy Services LLC

Statements of Changes in Members' Capital

(In Thousands)

Balance, January 1, 2001, as restated (*Note 2*)	$83,600
Net income	16,804
Other comprehensive loss (*Note 6*)	(709)
Comprehensive income	16,095
Contributions from Members	15,000
Distributions to Members	(20,000)
Balance, December 31, 2001	94,695
Net income	41,514
Other comprehensive loss (*Note 6*)	(861)
Comprehensive income	40,653
Distributions to Members	(49,000)
Balance, December 31, 2002	86,348
Net income	**63,313**
Other comprehensive income (*Note 6*)	**2,755**
Comprehensive income	**66,068**
Distributions to Members	**(51,609)**
Balance, December 31, 2003	**$100,807**

See accompanying notes.

SouthStar Energy Services LLC

Statements of Cash Flows

	Year ended December 31		
	2003	**2002**	**2001**
	(In Thousands)		
Operating activities			
Net income	**$63,313**	$ 41,514	$16,804
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation	**228**	222	164
Amortization	**919**	1,742	1,117
Provision for doubtful accounts	**16,627**	26,240	36,740
Net changes in operating assets and liabilities:			
Accounts receivable and unbilled revenue	**(27,558)**	(26,320)	71,592
Inventories	**6,691**	(1,157)	(188)
Prepaid gas and expenses	**(4,122)**	(185)	(35)
Restricted cash	**4,830**	(6,896)	(1,588)
Other current assets	**(300)**	-	2,968
Accounts payable	**(9,689)**	10,066	(25,470)
Accrued gas costs	**8,178**	11,280	(38,120)
Customer deposits	**(5,094)**	8,532	2,657
Financial instruments	**(5,530)**	2,174	(709)
Accrued compensation	**403**	596	(1,281)
Other accrued expenses	**232**	1,477	(7,225)
Net cash provided by operating activities	**49,128**	69,285	57,426
Investing activities			
Capital expenditures	**(1,955)**	(57)	(444)
Net cash used in investing activities	**(1,955)**	(57)	(444)
Financing activities			
Contributions from Members	**–**	–	15,000
Distributions to Members	**(51,609)**	(49,000)	(20,000)
Net additions (payments) on revolving line of credit	**5,169**	(17,212)	(53,865)
Net cash used in financing activities	**(46,440)**	(66,212)	(58,865)
Net increase (decrease) in cash and cash equivalents	**733**	3,016	(1,883)
Cash and cash equivalents at beginning of year	**6,906**	3,890	5,773
Cash and cash equivalents at end of year	**$7,639**	$6,906	$3,890
Supplemental disclosures of cash flow information			
Cash paid during the year for interest	**$282**	$348	$3,512

See accompanying notes.

SouthStar Energy Services LLC

Notes to Financial Statements

December 31, 2003

1. Organization

SouthStar Energy Services LLC (the "Company") is a limited liability corporation formed on July 1, 1998 by Georgia Natural Gas Company ("GNGC"), a wholly owned subsidiary of AGL Resources Inc., Piedmont Energy Company ("Piedmont"), and Dynegy Energy Services, Inc. ("Dynegy"), to offer natural gas, propane, fuel oil, electricity, and related services to residential, commercial and industrial users in the Southeastern United States. The Company was certified as a retail marketer with the Georgia Public Service Commission on October 6, 1998. The Limited Liability Company Agreement of SouthStar Energy Services LLC (the "LLC Agreement") provides for the Company to be dissolved ten years from the date of organization at the election of one or more Members. Absent such an action, the Company will dissolve twenty years from the date of organization unless extended by unanimous vote of the Members.

On March 11, 2003, GNGC completed the purchase of Dynegy's 20% interest in the Company. As a result, GNGC owns a non-controlling 70% interest in the Company. Piedmont maintained its 30% economic ownership interest in the Company subsequent to March 11, 2003. Although GNGC owns a 70% economic interest in the Company, it does not have a controlling interest, as all matters of significance require the unanimous vote of the Members.

As part of the transaction, the Members agreed to permit Dynegy Marketing and Trade to exit its contract to provide asset management and gas procurement and supply services for the Company, effective January 31, 2003.

2. Summary of Significant Accounting Policies

Cash and Cash Equivalents

The Company considers all highly liquid investments with maturities of three months or less when purchased to be cash equivalents.

Restricted Cash

Restricted cash represents deposits held to secure credit extended to certain customers.

Inventories

Gas inventories are stated at the lower of cost or market with cost determined using a weighted average method.

Accounts Receivable

The Company performs credit evaluations on new customers and requires deposits from certain customers. Customers are generally billed monthly and accounts receivable are generally due within 30 days. The majority of the Company's customers do not maintain long-term contracts with the Company. Provisions for doubtful accounts are recorded to reflect the expected net realizable value of accounts receivable based on historical collection trends. Accounts receivable are charged off once the Company has completed all reasonable collection efforts.

Property and Equipment

Property and equipment is stated at cost and consists of office furniture, computer software and equipment and leasehold improvements. Depreciation is computed using the straight-line method over the estimated useful lives of the assets.

Intangibles

Intangible assets consisted primarily of customer contracts and lists contributed by the Members at the Company's inception, which were being amortized on a straight-line basis over five years. Intangibles also include the purchase price for firm market customers acquired from other certified marketers, which is being amortized on a straight-line basis over five years.

During the year ended December 31, 2001, the Company determined that the initial intangibles recorded on its opening balance sheet were overstated by $7,682,000. The Company also determined that the original useful life of twenty years assigned to the intangibles at inception was based on the term of the LLC Agreement. Such useful life should have been determined based on the useful lives of the underlying gas contracts. The Company determined such useful lives should have been five years. These errors occurred as a result of a misuse of information, which existed at the date of the Company's inception. The Company reduced January 1, 2001 Members' capital by $8,447,000 to adjust for the effect of these errors. The effect of the adjustment was not deemed to be material to the results of operations or financial position of the Company as of and for the year ended December 31, 2001.

Revenues

The Company recognizes revenues as gas is delivered to customers. Unbilled revenue represents gas delivered but not yet billed to customers and is based on the estimated usage from the latest meter reading to the end of the accounting period.

Income Taxes

The Company is treated as a partnership for federal and state income tax purposes. As such, the Company is not liable for income taxes as the taxable income or loss is reported in the income tax returns of the Members. Accordingly, the accompanying financial statements do not provide for federal or state income taxes.

The proforma provision for income taxes represents a provision for federal and state income taxes as if the Company had operated as a C Corporation for income tax purposes.

Members' Capital

The LLC Agreement calls for capital accounts to be established for each Member. The Executive Committee, by its unanimous vote, can require the Members to contribute additional capital to the Company. Withdrawals of capital from the Company also require unanimous Executive Committee approval.

The Members are parties to a Capital Contribution Agreement (the "Contribution Agreement") that requires each Member to contribute additional capital to the Company to pay invoices for goods and services received from any vendor that is affiliated with a Member whenever funds are not otherwise available to pay those invoices. The capital contributions to pay affiliated vendor invoices are repaid as funds become available, but repayment is subordinated to the Company's revolving line of credit with its financial institution. There was no activity related to the Contribution Agreement during the years ended December 31, 2003 and 2002. A Member contribution of $15 million to the Company was repaid to the Members under the Contribution Agreement during the year ended December 31, 2001.

Accounting Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Comprehensive Income

Comprehensive income consists of net income and other gains and losses affecting Members' capital that, under GAAP, are excluded from net income. For the Company, such items consist primarily of unrealized gains and losses on certain derivatives.

Advertising

Advertising expenses are recognized as incurred and aggregated $3,169,000 and $4,743,000 for the years ended December 31, 2003 and 2002, respectively. The Company incurred no expenses for advertising during the year ended December 31, 2001.

Financial Instruments

The Company utilizes financial contracts to hedge the price volatility of natural gas. These financial contracts (futures, options, and swaps) are considered to be derivatives, with prices based on selected market indices. The Company accounts for these instruments in accordance with Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* ("SFAS No. 133"). Those derivative transactions that qualify as cash flow hedges are reflected in the balance sheets at the fair values of the open positions with the corresponding unrealized gain or loss included in other comprehensive income, a component of Members' capital. Those derivative transactions that are not designated as hedges are reflected in the balance sheets at fair values with corresponding unrealized gains or losses included in cost of sales in the statements of income. The effectiveness of the derivative as a hedge is based on a high correlation between changes in its value and changes in the value of the underlying hedged item. Ineffectiveness related to the Company's derivative transactions designated as hedges is not material at December 31, 2003 and 2002. The termination of a derivative designated as a cash flow hedge will result in the reclassification of amounts included in accumulated other comprehensive income to the statement of income if the hedged transaction is no longer probable of occurring, otherwise the reclassification to the statement of income of accumulated other comprehensive income will be deferred until the hedged transaction affects earnings. The Company includes in operating results amounts received or paid when the underlying transaction settles. Fair value is based on published market indices and other appropriate valuation methodologies. The Company's use of derivatives is governed by a risk management policy and is limited to hedging activities. The Company does not enter into or hold derivatives for trading or speculative purposes.

The Company 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. These contracts are accounted for using the intrinsic value method under the guidelines of EITF 99-2, *Accounting for Weather Derivatives.*

The fair values of other financial instruments, which include cash, accounts receivable, accounts payable, accrued expenses and other liabilities, approximate their carrying values due to their short-term nature. See Note 6 for further discussion.

New Accounting Standards

In June 2001, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets* ("SFAS No. 142"). This Statement changes the accounting for goodwill and intangible assets with indefinite useful lives from an amortization method to an impairment-only approach. The Company adopted SFAS No. 142 on January 1, 2002. Such adoption did not have a significant impact on the Company's financial statements.

In April 2003, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 149, *Amendment of FASB Statement No. 133 on Derivative and Hedging Transactions* ("SFAS No. 149"). This Statement clarifies under what circumstances a contract with an initial net investment meets the characteristic of a derivative as discussed in SFAS No. 133. In addition, it clarifies when a derivative contains a financing component that warrants special reporting in the statement of cash flows. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003, except for certain hedging relationships designated after June 30, 2003. The Company adopted SFAS No. 149 on July 1, 2003. Such adoption did not have a significant impact on the Company's financial statements.

Reclassifications

Certain reclassifications were made to the prior year's financial statements to conform with the current year's presentation.

3. Revolving Line of Credit

In October 2000, the Company entered into a revolving line of credit (the "Revolver") with a group of banks to provide the working capital needed to meet seasonal demands. Maximum borrowings under the Revolver are $75,000,000. The Revolver is collateralized by varying percentages of eligible accounts receivable (85%), unbilled revenue (75%) and inventory (80%) of the Company. As of December 31, 2003 and 2002, $66,831,000 and $69,824,000, respectively, were available under the Revolver. The Revolver expires on March 19, 2004. The base interest rate on the Revolver is Prime and/or LIBOR plus a margin. The margin rate applied to LIBOR begins at 2% for earnings before interest, taxes, depreciation and amortization ("EBITDA") less than $9 million and is incrementally reduced to a minimum of 1.7% at EBITDA of $13 million or greater. The interest rate for borrowings under the Revolver was 4.00% and 4.25% at December 31, 2003 and 2002, respectively. Interest under the Revolver is payable monthly. At December 31, 2003 and 2002, the Company had irrevocable letters of credit totaling $3,000,000 and $5,176,000, respectively, securing certain of the Company's pipeline capacity purchases. Amounts secured under letters of credit reduce the availability under the Revolver.

4. Commitments and Contingencies

The Company has entered into operating leases for office facilities and office equipment. Rental expense under operating leases was $731,000, $656,000 and $567,000 for the years ended December 31, 2003, 2002 and 2001, respectively. In September 2003, the Company entered into a three year operating lease agreement for office space with an affiliate of GNGC, which expires on July 7, 2006. Rent expense for the year ended December 31, 2003 includes $120,000 related to this lease.

The future minimum rentals under non-cancelable operating leases in effect at December 31, 2003 are as follows:

2004	$632,000
2005	487,000
2006	205,000
	$ 1,324,000

At December 31, 2003, the Company had certain natural gas purchase commitments. These purchase commitments are correlated directly to fixed price sales contracts with certain of the Company's customers. Obligations under these purchase agreements at December 31, 2003 aggregated $7,746,000 through November 2004. Obligations under these purchase agreements at December 31, 2002 aggregated $14,330,000 through 2003.

During the years ended December 31, 2003, 2002 and 2001, the Company purchased natural gas of $42,829,000, $32,480,000 and $21,977,000, respectively, under similar gas purchase agreements.

The Company also had natural gas purchase commitments related to the supply of minimum natural gas volumes during the winter months. These commitments are priced on an index-plus-premium basis. At December 31, 2003, the Company had obligations under these agreements for 15,745,000 dekatherms through March 2004. At December 31, 2002, the Company had obligations under these agreements for 13,181,000 dekatherms through March 2003. During the years ended December 31, 2003 and 2002, respectively, the Company purchased natural gas of $81,911,000 and $38,325,000 under similar gas purchase agreements. There were no purchases under similar agreements during the year ended December 31, 2001.

The Company entered into a new contract effective December 1, 2002 with its existing service provider for the outsourcing of its billing and customer service functions. The contract expires on November 30, 2007. During the years ended December 31, 2003, 2002 and 2001, the Company incurred $22,359,000, $26,441,000 and $20,018,000, respectively, for these services. The Company can terminate the agreement at any time without cause. In the first twelve months of the contract there is no penalty associated with such a termination. After that period, termination requires paying a penalty, which is calculated, based on the date of termination.

5. Employee Benefit Plans

The Company has a qualified incentive savings plan, which provides an opportunity for all eligible employees to contribute to their retirement savings. The Company matches 100% of the employee's contribution up to a maximum Company contribution of 5% of each employee's base compensation. For the years ended December 31, 2003, 2002 and 2001, the Company's contributions under this plan were $208,000, $155,000 and $132,000, respectively.

6. Financial Instruments

The Company entered into natural gas financial contracts in order to hedge its natural gas inventory and to fix the price of a portion of its natural gas purchases. These contracts settle monthly with varying maturity dates through September 2005. At December 31, 2003, the fair value of open positions was reflected in the financial statements as an asset aggregating $4,541,000 offset by the combination of an increase to other comprehensive income (a component of Members' capital) of $1,185,000 for the portion of the open positions designated as hedges and a decrease of $3,356,000 to cost of sales for the portion of the open positions not designated as hedges. Approximately $1,100,000 of the other comprehensive income balance at December 31, 2003 is expected to be reclassified into the statement of income within the next twelve months as the underlying transactions settle. At December 31, 2002, the fair value of open positions was reflected in the financial statements as a liability of $3,744,000 offset by the combination of an increase to other comprehensive loss (a component of Members' capital) of $1,570,000 for the portion of the open positions designated as hedges and an increase of $2,174,000 to cost of sales for the portion of the open positions not designated as hedges.

To preserve margins in the event of warmer than normal weather in the winter months, the Company purchased option-based weather derivative contracts for the months of November 2003 through March 2004. The contracts contain strike amount provisions based on cumulative heating degree days ("HDD") for the covered periods. Based upon actual HDD's in November and December 2003, no receivable was recorded at December 31, 2003. Under a similar option-based weather derivative contract for the months of November 2002 through March 2003, based upon actual HDD's in November and December 2002, no receivable was recorded at December 31, 2002.

7. Related Party Transactions

In conjunction with the Georgia Natural Gas Competition and Deregulation Act, the Company is assigned rights to capacity from Atlanta Gas Light Company ("AGLC"), an affiliate of GNGC, based on market share.

The Company purchased natural gas and pipeline capacity from affiliates of GNGC, Dynegy and Piedmont as follows:

	Year ended December 31		
	2003	**2002**	**2001**
GNGC	**$181,348,000**	$243,113,000	$190,000,000
Dynegy	**15,791,000**	178,115,000	445,000,000
Piedmont	**1,096,000**	9,615,000	12,000,000

The Company owed the following amounts to affiliates of GNGC, Dynegy and Piedmont related to natural gas purchases and other services:

	December 31	
	2003	2002
GNCC	$10,703,000	$4,368,000
Dynegy	-	15,828,000
Piedmont	-	254,000

The amounts due to affiliates in the table above are included in accrued gas costs on the balance sheet as of December 31, 2003 and 2002, respectively.

Effective April 1, 2003, the Georgia Public Service Commission ordered a change in the assets assigned to marketers with certain assets reverting back to AGLC, an affiliate of GNGC. As a result of this stipulation, the Company was required to sell 846,000 dekatherms of natural gas to AGLC aggregating $4,368,000. The sale was transacted at market index rates in effect at April 1, 2003.

For the year ended December 31, 2001, the Company was billed $5,701,000 by an affiliate of GNGC for customer enrollment and ongoing customer service.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on January 28, 2004.

AGL RESOURCES INC.

By: /s/ Paula G. Rosput
Paula G. Rosput
Chairman, President and Chief Executive Officer

Power of Attorney

KNOW ALL MEN BY THESE PRESENT, that each person whose signature appears below constitutes and appoints Paula G. Rosput, Richard T. O'Brien and Paul R. Shlanta, and each of them his or her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K for the calendar year ended December 31, 2003, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite or necessary to be done, as fully to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated as of January 28, 2004.

Signatures	Title
/s/ Paula G. Rosput Paula G. Rosput	Chairman, President and Chief Executive Officer (Principal Executive Officer) and Director
/s/ Richard T. O'Brien Richard T. O'Brien	Executive Vice President and Chief Financial Officer (Principal Accounting and Financial Officer)
/s/ Thomas D. Bell Jr. Thomas D. Bell Jr.	Director
/s/ Charles R. Crisp Charles R. Crisp	Director
/s/ Michael J. Durham Michael J. Durham	Director
/s/ Arthur E. Johnson Arthur E. Johnson	Director
/s/ Dennis M. Love Dennis M. Love	Director
/s/ D. Raymond Riddle D. Raymond Riddle	Director
/s/ James A. Rubright James A. Rubright	Director
/s/ Felker W. Ward, Jr. Felker W. Ward, Jr.	Director

Schedule II

AGL Resources Inc. and Subsidiaries

VALUATION AND QUALIFYING ACCOUNT - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS FOR THE YEARS ENDED DECEMBER 31, 2003, DECEMBER 31, 2002 AND SEPTEMBER 30, 2001 AND THE THREE MONTHS ENDED DECEMBER 31, 2001.

In millions	
Balance at September 30, 2000	$8.3
Provisions charged to income in fiscal 2001	10.1
Accounts written off as uncollectible, net in fiscal 2001	(5.0)
Balance at September 30, 2001	13.4
Provisions charged to income in the transition period	4.7
Accounts written off as uncollectible, net in the transition period	(10.9)
Balance at December 31, 2001	7.2
Provisions charged to income in calendar 2002	2.6
Accounts written off as uncollectible, net in calendar 2002	(7.5)
Balance at December 31, 2002	2.3
Provisions charged to income in calendar 2003	6.0
Accounts written off as uncollectible, net in calendar 2003	(5.8)
Balance at December 31, 2003	**$2.5**