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WHAT DO YOU SEE?

RESOURCES INC. 2004 ANNUAL REPORT


ELIZABETHTOWN GAS
ELKTON GAS
VIRGINIA NATURAL GAS
SALTVILLE, VA. STORAGE
VIRGINIA GAS
CHATTANOOGA GAS
ATLANTA GAS LIGHT
JEFFERSON ISLAND STORAGE & HUB
FLORIDA CITY GAS
Service Territory
Local Distribution Companies
Other Assets
Major Interstate Pipelines
Columbia Pipeline
Transco Pipeline
Sonat Pipeline
East Tennessee Pipeline

AGL Resources

AT A GLANCE — 2004

More than 2,900 AGL Resources employees serve our 2.2 million customers.

DISTRIBUTION OPERATIONS

Atlanta Gas Light is the largest natural gas distributor in the Southeast, serving 237 communities in the state of Georgia. It provides gas delivery service to more than 1.5 million residential, commercial and industrial customers and delivers approximately 238 billion cubic feet of gas annually. It also owns and operates more than 29,000 miles of distribution pipeline and three liquefied natural gas (LNG) plants.

Chattanooga Gas provides retail natural gas sales and transportation services to approximately 60,000 customers in Hamilton County and Bradley County, Tennessee. It delivers approximately 16.7 billion cubic feet of gas annually, and also owns and operates more than 1,400 miles of pipeline and one LNG plant.

Elizabethtown Gas provides natural gas service to approximately 265,000 residential, commercial and industrial customers in northwestern New Jersey. It delivers approximately 60.5 billion cubic feet of gas annually through more than 2,900 miles of distribution pipeline.

Florida City Gas provides natural gas service to approximately 104,000 residential, commercial and industrial customers in southeastern and east central Florida. It delivers approximately 9.5 billion cubic feet of gas annually through more than 6,100 miles of distribution pipeline.

Virginia Natural Gas provides natural gas service to more than 256,000 residential, commercial and industrial customers in southeastern Virginia. It delivers approximately 35 billion cubic feet of gas annually through more than 4,800 miles of distribution pipeline. It also owns and operates a 156-mile high-pressure, large-diameter transmission pipeline serving major wholesale customers.

Service is also provided to 5,900 natural gas customers in Elkton, Maryland by *Elkton Gas* and 300 customers in southwestern Virginia by *Virginia Gas*.

WHOLESALE SERVICES

Sequent Energy Management provides customers in the eastern half of the United States with proven ways to optimize their natural gas asset portfolio and increase cost effectiveness, from wellhead to burner tip. Sequent offers natural gas asset management, producer and storage services, and full-requirements gas supply, including peaking needs.

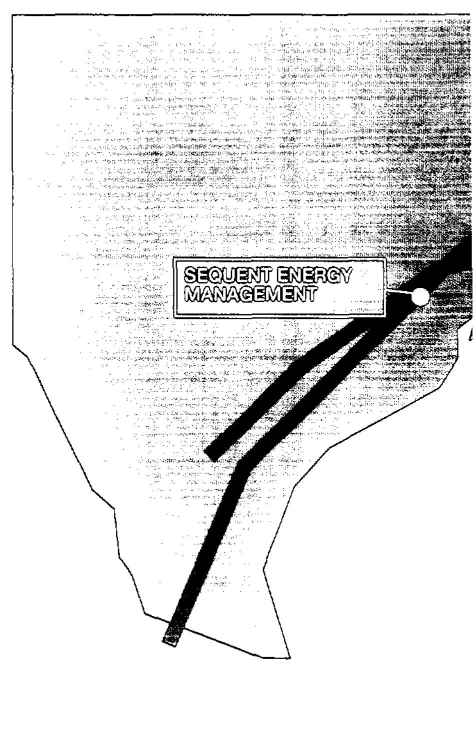
ENERGY INVESTMENTS

SouthStar Energy Services is a joint venture operating in Georgia under the trade name Georgia Natural Gas. The business supplies natural gas to more than 525,000 residential and commercial customers in Georgia and 500 industrial customers throughout the Southeast.

Pivotal Energy Development operates Pivotal Jefferson Island Storage & Hub, a high-deliverability natural gas storage facility in Louisiana. In addition, through our wholly owned subsidiary Pivotal Propane of Virginia, it is managing the development, construction and operation of a peaking propane plant in Virginia.

Saltville Storage is a 50% member of Saltville Gas Storage Company, LLC, a joint venture formed in 2001 with a subsidiary of Duke Energy Corporation to develop a high-deliverability natural gas storage facility in Saltville, Virginia.

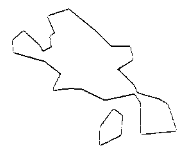
AGL Networks is a carrier-neutral provider that leases telecommunications fiber to a variety of customers in the Atlanta, Georgia and Phoenix, Arizona metropolitan areas. AGL Networks provides conduit, dark fiber and telecommunications construction services to its customers.



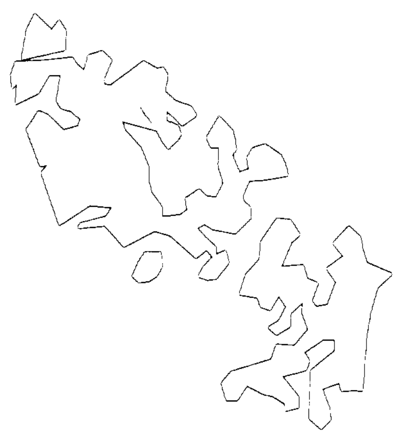
WE SEE OPPORTUNITY WHERE WE ARE,

AND WHERE WE CAN BE.

WE SEE DIFFERENTLY.



With our 2004 acquisitions of Jefferson Island Storage & Hub and of NUI Corporation (including several natural gas utilities), AGL Resources is positioned to become the pre-eminent natural gas distributor on the East Coast. These assets, along with the planned 2005 additions of our Pivotal propane plant in Virginia and Macon pipeline expansion, have significantly strengthened our infrastructure portfolio. We now serve 2.2 million retail residential, commercial and industrial customers, plus a substantial portion of large wholesale customers throughout the eastern half of the U.S. Step by step we're building value, and each step brings new fields of opportunity into view.



OUR BUSINESS MAY BE UTILITIES, BUT OUR JOB IS TO CREATE VALUE.

AGL Resources has generated steady, consistent gains for our investors over the past five years. We are an organization with an appetite for achievement that is focused firmly on creating value. Simply put, we never stop searching—and as a result, we find opportunities to create value in places others may dismiss or discount. We understand the power of incremental gains to build meaningful returns. We scan the horizon continually for new opportunities. And the specific assets or projects we select must meet demanding criteria: a favorable purchase price and the ability to add value both quickly and over time.

Our 2004 acquisitions are consistent with this strategy and these criteria, and position us for further incremental growth.

- The purchase of a natural gas storage facility, ideally positioned to support current natural gas storage demand and rising LNG imports, substantially strengthens our infrastructure portfolio.

- Utilities in New Jersey, Florida, Maryland and Virginia, acquired through our purchase of NUI Corporation, offer significant opportunities to use our core capabilities to improve performance for both customers and investors.

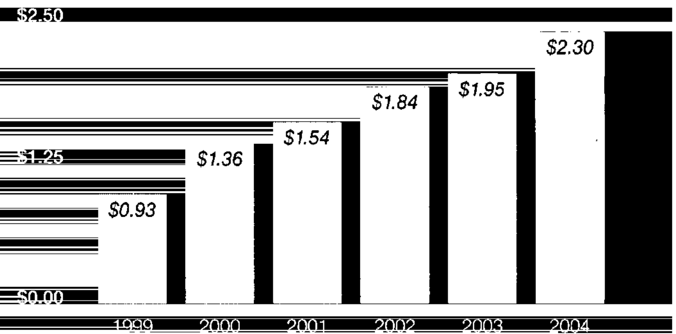
Our team of businesses and individuals is committed to the hard work of building value one step at a time. And as you can see in the charts on page 3, this commitment is paying dividends.

ARNINGS PER SHARE

sic earnings per share at right exclude the following:

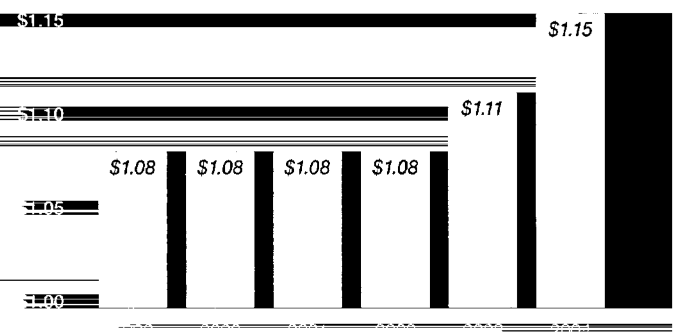
- in 2003, an 8-cent gain on the sale of company property,
  [illegible] of the proceeds to a charitable organization
- in 2001, a 13-cent gain on the sale of a subsidiary
- in 2000, a 4-cent gain on certain items
- in 1999, a 39-cent gain on the sale of joint venture interests

[illegible] these items, basic earnings per share were $2.03 in [illegible] $1.57 in 2001, $1.40 in 2000 and $1.32 in 1999.



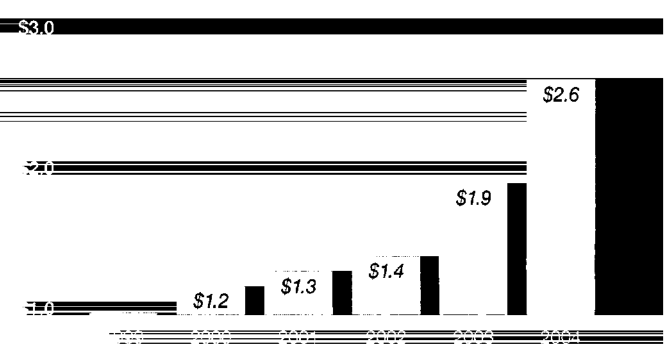
IVIDEND PER SHARE

[illegible]

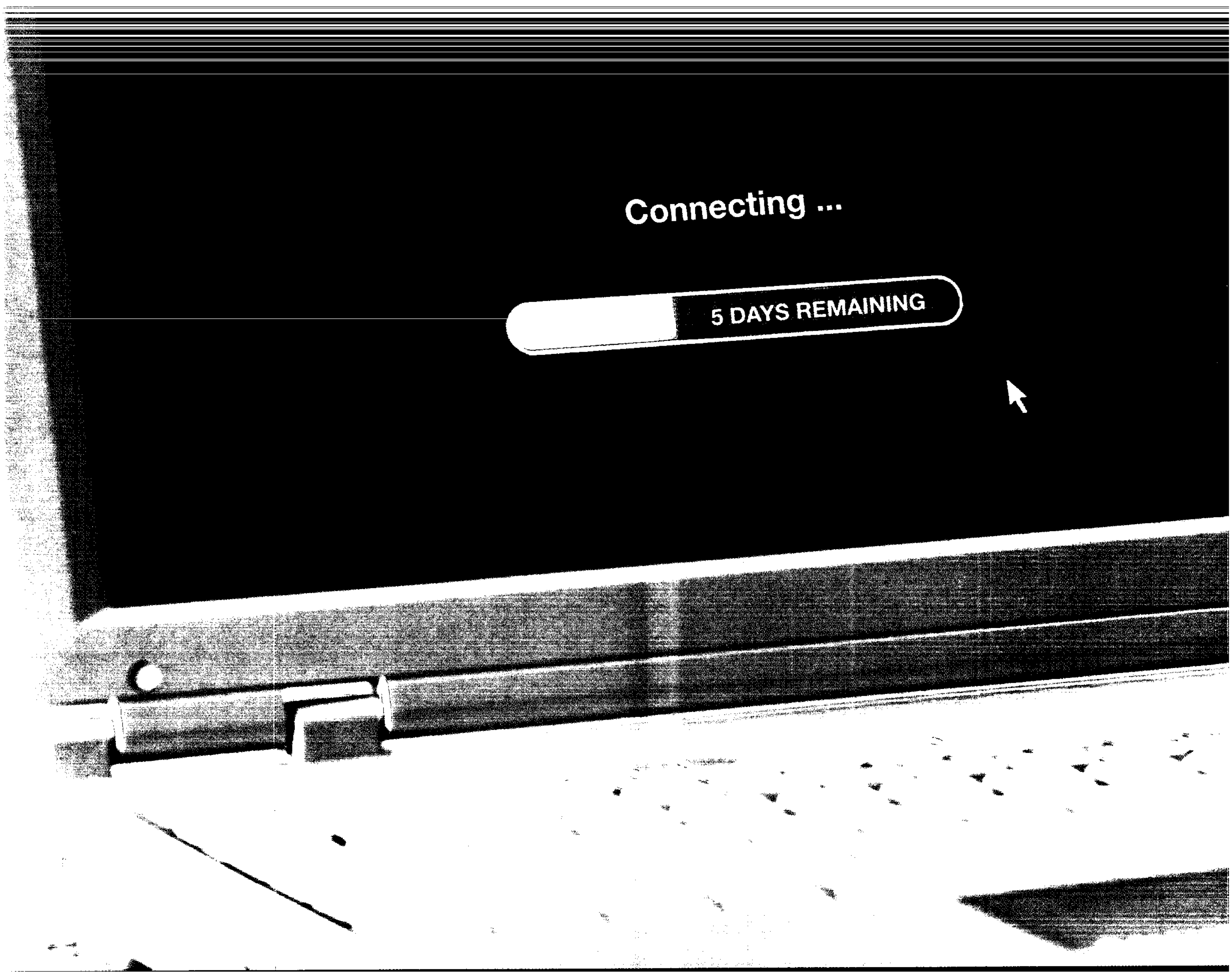


ARKET CAPITALIZATION

[illegible] December 31, in billions



THE REAL WORLD DOESN'T OPERATE ON UTILITY STANDARD TIME. WHY SHOULD WE?



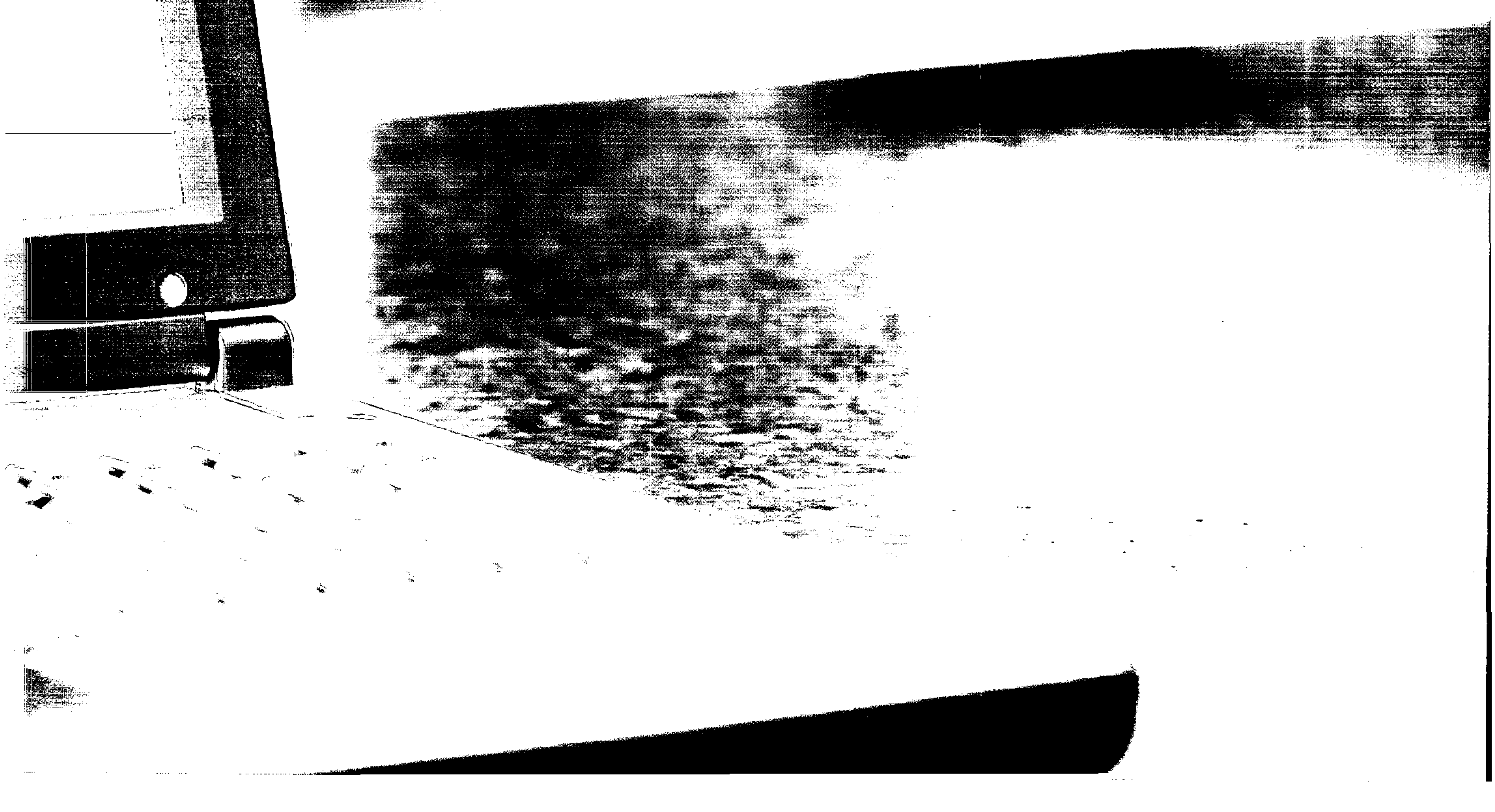
High-quality products you can rely on to be there when you need them. Fair prices. Swift delivery. Responsive service. These are the things consumers expect in the rest of the economy. We believe they deserve to expect them from utilities too.

AGL Resources is committed to:

EXPERT SERVICE
All service delivered in one trip. All questions answered in one call.

NO WAITING
Same day/next day service or by appointment. Live service representatives to talk to.

BEST IN TECHNOLOGY
State-of-the-art systems that improve speed, safety and ease of doing business with us. Continued commitment to reinvest in the business.



When AGL Resources enters a new community, we bring with us four values that guide our business conduct. We will behave with honesty. We will create value. We will be generous in spirit. We will operate inside the lines.

Our job is to work well inside the rules and regulations under which we are required to operate, and not to push the envelope with respect to those rules. Our job is to provide a high-quality product, asking more of ourselves than others do. Our job is to manage the energy assets of our utility franchises to the benefit of customers. Our job is to deliver excellent customer service — because our customers have a choice in meeting their energy needs, and we want them to choose natural gas delivered by our franchises.

We never stop looking for opportunities to improve performance — from reducing the amount of time it takes to turn on, turn off and read meters, to minimizing the amount of time customers spend on the phone arranging for service. That's why we work to identify, develop and integrate new tools and technologies that make us better at what we do. The scale of our operations now makes it easier to drive best practices through our organizations.

The industry-leading operating efficiencies we've developed over the past five years in our distribution companies in Georgia, Tennessee and Virginia have improved service for customers and increased returns for investors. In December 2004, we welcomed 375,000 former NUI customers in New Jersey, Maryland, Virginia and Florida, and we look forward to working just as hard for them.

AGL Resources is dedicated to the idea that every good thing starts with getting it right for our customers. Our aspiration is to develop a national reputation for excellent customer service.

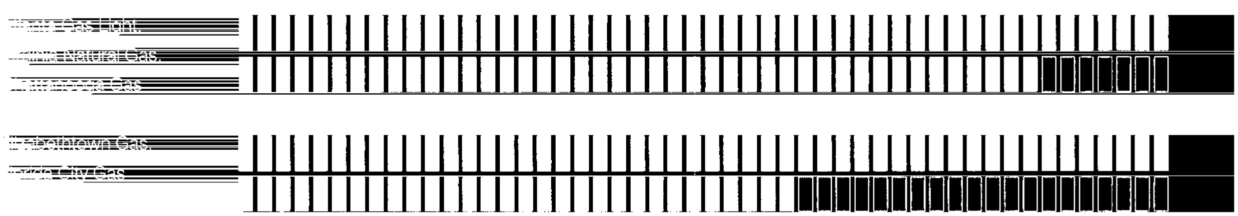
AGL Resources' utility franchises now serve more than 2.2 million customers in six states stretching from Florida to New Jersey. Our operations span every climate zone on the Eastern Seaboard. We deliver more than 350 billion cubic feet of natural gas annually through these franchises, and own and operate more than 41,000 miles of pipeline and six LNG plants.

Our focus will always be the customer. We listen. We follow a "one call, that's all" philosophy in our customer care center, and a "one trip, that's it" practice for meeting customers' expectations in their homes.

We see a clear opportunity to improve performance and service for our customers in New Jersey and Florida.

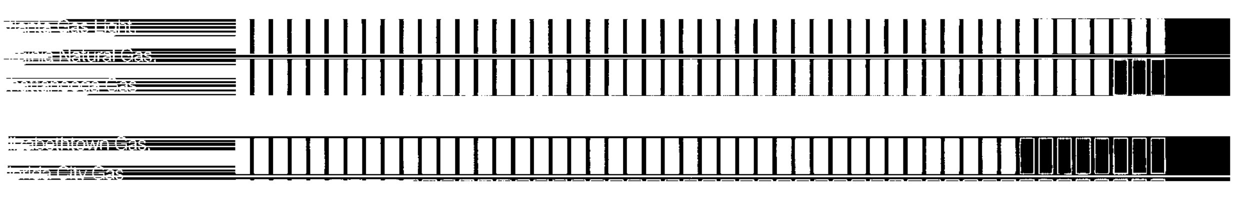
2004 CUSTOMER SATISFACTION

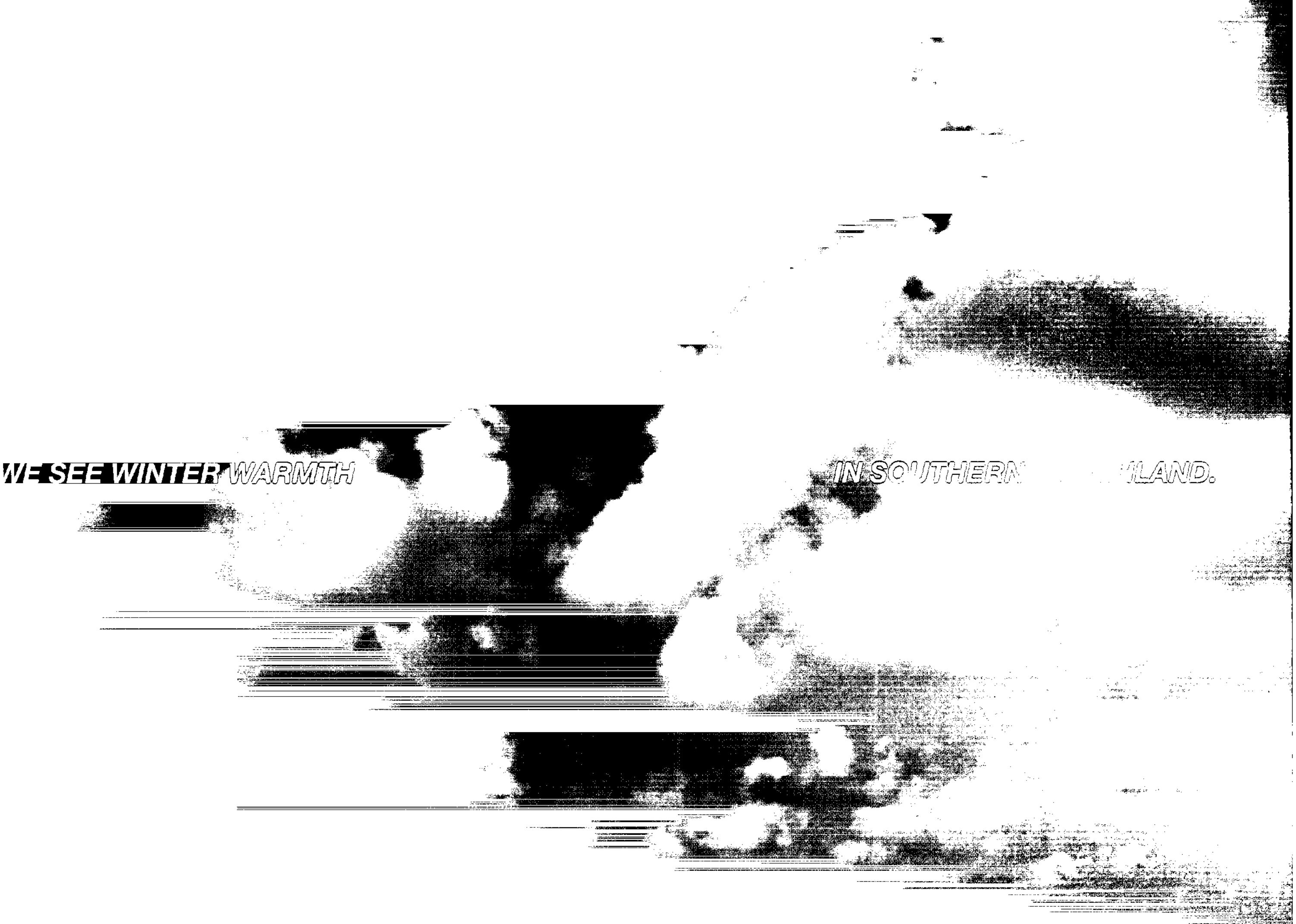
AGL Resources' legacy franchises achieved a 93% customer satisfaction rating in 2004, and we're committed to improving that performance. Customer satisfaction ratings for Elizabethtown Gas and Florida City Gas measured 80% for the same period.

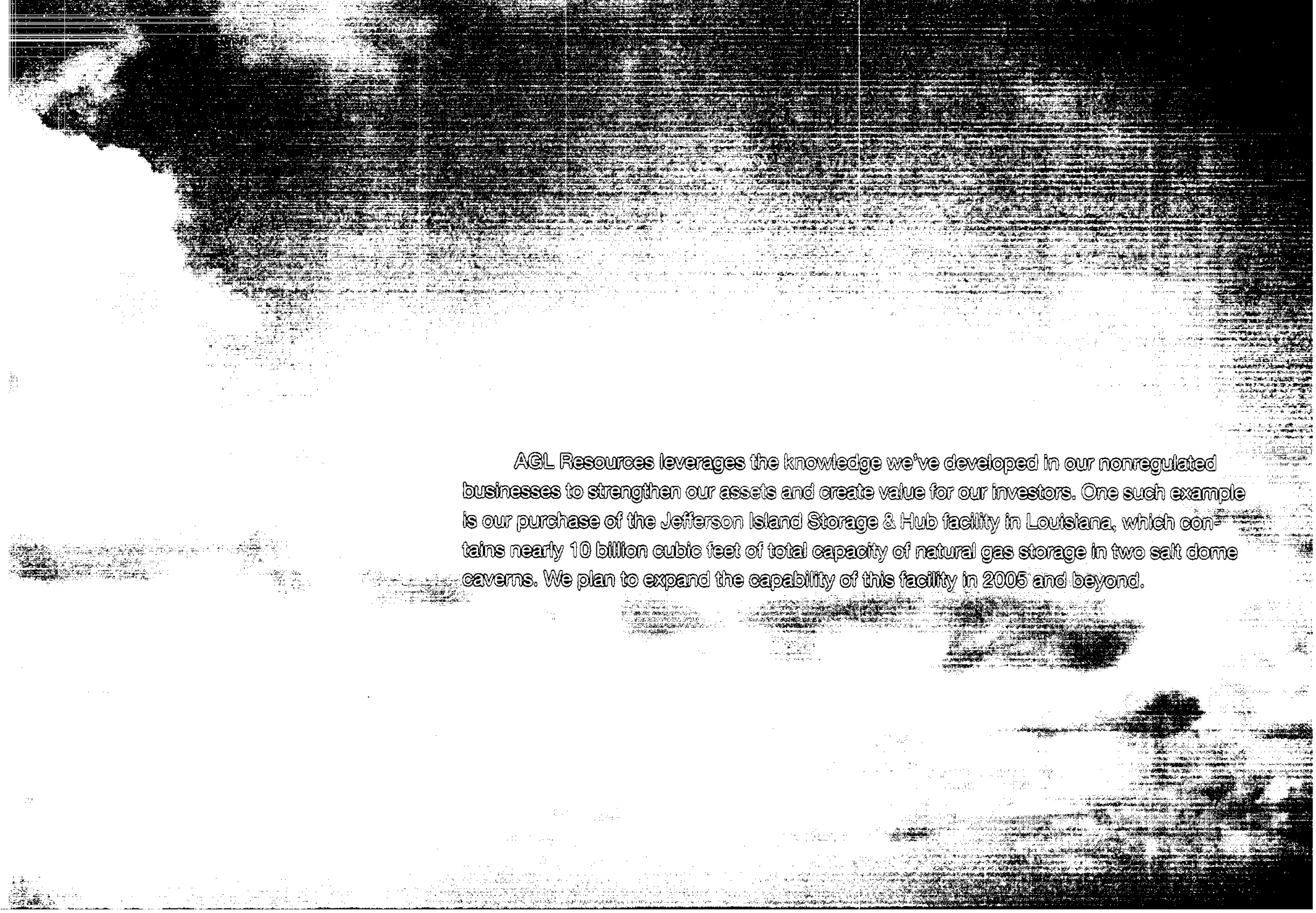


2004 METER READING

Bill accuracy depends heavily on monthly meter reading. AGL Resources' legacy franchises read close to 100% of meters each month in 2004. Elizabethtown and Florida City Gas read only 42% of customer meters.




WE SEE WINTER WARMTH
IN SOUTHERN
LAND.



AGL Resources leverages the knowledge we've developed in our nonregulated businesses to strengthen our assets and create value for our investors. One such example is our purchase of the Jefferson Island Storage & Hub facility in Louisiana, which contains nearly 10 billion cubic feet of total capacity of natural gas storage in two salt dome caverns. We plan to expand the capability of this facility in 2005 and beyond.

As our natural gas distribution business continues to expand, it is more important than ever to invest in strategic assets that provide significant flexibility and the opportunity to offer dependable service to all our customers. In 2004, we took several steps to protect reliable and economical delivery of natural gas.

Peaking assets are more important than ever before in the energy industry. While natural gas usage per customer has remained relatively flat or declined, the way in which this gas is consumed has changed as appliances and homes become more energy efficient. In particular, weather drives the use of natural gas — which means more assets are needed to meet peak demand but for fewer days per year. The challenge for suppliers and gas utilities is to create a portfolio of assets that will serve this growing peak demand without forcing the customer to pay unnecessary fixed costs for resources.

Recognition of the need for peaking capacity, coupled with our concerns about the ability of major pipeline companies to make the capital investments necessary to meet peak demands, led us to move quickly on two projects to ensure system reliability and high-quality service to customers. In Virginia, our construction of a propane-air peaking plant will reduce our dependence on major interstate pipelines for critical supply during the coldest days of the year. In Georgia, we agreed to acquire 250 miles of interstate pipeline serving the Macon-to-Atlanta corridor. This purchase will save customers money by improving access to one of our LNG facilities and by enhancing the overall reliability of our Georgia distribution system.

Acquisition of the Jefferson Island facility adds substantial natural gas storage capacity to our infrastructure portfolio, and positions us for an even stronger future through the facility's expansion potential. Located on the Gulf Coast, the two salt dome gas storage caverns are connected to six major interstate pipelines via the Henry Hub. Jefferson Island creates the opportunity for an additional income stream by enhancing our ability to provide custom-tailored services to energy clients throughout the eastern United States. Capacity can be expanded economically when market conditions and operating parameters warrant.

Even as we develop and acquire new assets, we will continue to optimize the assets we already own. Sequent Energy Management's wholesale marketing and asset management services continue to enhance results for our utility franchises, and for other energy clients east of the Rockies. In 2004, Sequent's asset optimization activities returned \$1.3 million to Chattanooga Gas customers, \$3.0 million to Virginia Natural Gas customers and \$3.8 million to Georgia's Universal Service Fund. Sequent will supply asset management services to Elizabethtown Gas in New Jersey beginning in April 2005. We expect its client list will continue to grow as Sequent gains increased recognition for its ability to reduce costs and build value for its customers.

FOR THE FOURTH YEAR IN A ROW, WE PRODUCED RECORD RESULTS.

RECORD EARNINGS PER SHARE $2.30

RECORD SHARE PRICE $33.59

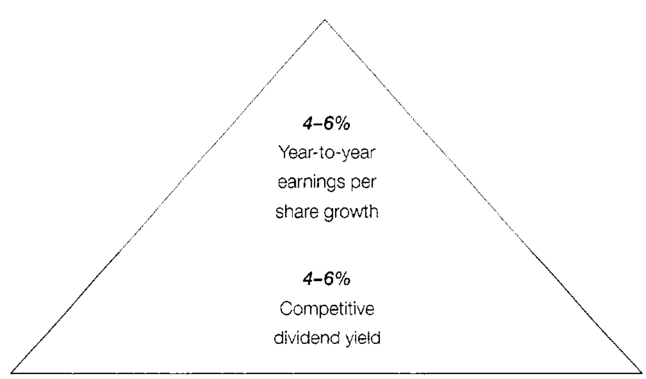
RECORD ANNUAL DECLARED DIVIDEND $1.16 PER SHARE

RECORD EQUITY MARKET CAPITALIZATION $2.6 BILLION

In 2004, AGL Resources dividends combined with earnings growth per share produced a 19% total return to shareholders. Our value proposition for value-oriented investors remains the same: to produce sustainable earnings and a substantial dividend – with an element of growth. Our goals remain realistic: to deliver consistent returns in the 8% to 12% range. A clear line of sight to EPS growth in 2005 should keep us on track to achieve this goal in the coming year. Our dividend was increased to $1.16 per share by the Board of Directors in April 2004 and to $1.24 per share in February 2005. Our payout ratio for 2004 was 50%, which remains among the lowest of our peer group, supporting our dividend and allowing room for future growth.

OUR LONG-TERM VALUE PROPOSITION

Target



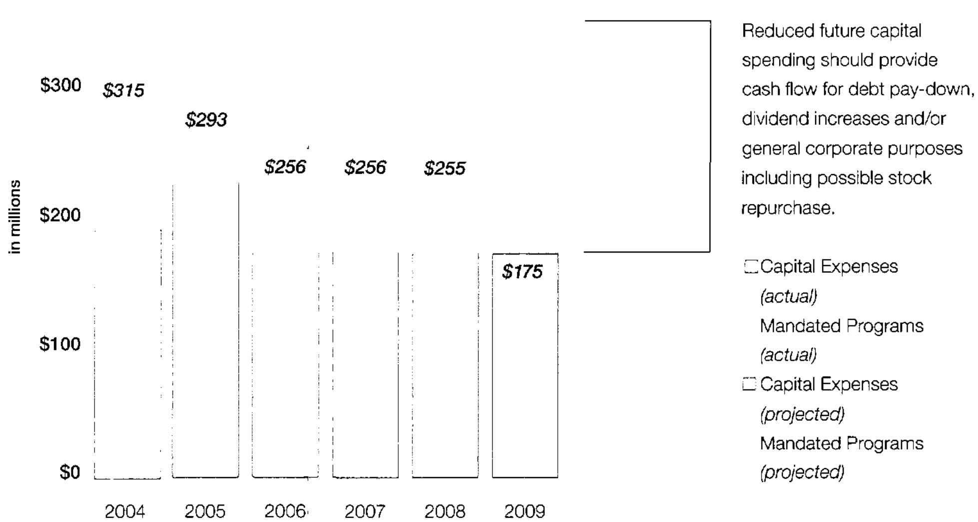
Actual

EPS growth from 2000–2004 has averaged 14%.

Dividend yield ranged from 3.5% to 4.3% during 2004.

We continued to focus on the strength of our balance sheet in 2004 by prudently capitalizing our acquisition of NUI and Jefferson Island Storage & Hub. We kept a close eye on our debt-to-total-capitalization ratio, overall cost of debt, liquidity position and interest coverage ratios. In November 2004, we issued 11 million shares of common stock raising $332 million to fund our 2004 acquisitions. We continue to execute on our strategy to buy assets economically that will add value in the near term as well as the long term. These new assets will provide additional opportunities to replicate our operational excellence model in new franchise territories and across a larger asset base.

Maintaining a strong balance sheet and adding new sources of incremental earnings are important steps toward improving cash flow and unlocking potential value for shareholders. Our cash flow picture also will be enhanced going forward by reduced spending over time related to two mandated regulatory programs — environmental cleanup and pipeline replacement. This improved cash flow position in succeeding years will place us in a better position than ever before to create sustainable value for shareholders.



TO OUR SHAREHOLDERS

Last year, I promised that in 2004 AGL Resources would continue to create value through a measured pace, a commitment to running the business for quality and for the long term, and a dividend strategy that rewards the patient investor. In the last 12 months, we have run our base business to provide strong earnings growth, earning a record \$2.30 per share. We have expanded our utility business to three new states (New Jersey, Florida and Maryland). We have become the largest gas distributor in the eastern U.S. with 2.2 million customers; and with an equity market capitalization of \$2.6 billion, we have become the largest of the pure gas distribution companies. We have expanded our asset mix through the accretive acquisition of Pivotal Jefferson Island Storage & Hub in Louisiana. We are in the process of constructing a new propane plant in Virginia and will shortly close on the acquisition of 250 miles of pipeline from Southern Natural Gas, an affiliate of El Paso Corporation, to reconfigure our infrastructure in Georgia. The Board of Directors raised our annual dividend twice in the last 12 months: in April 2004 by \$0.04 per share and in February 2005 by \$0.08 per share. Our annual dividend now stands at \$1.24 per share.

PAULA ROSPUT REYNOLDS Chairman, President and Chief Executive Officer

The performance on our commitment can perhaps best be viewed in the following way. The chart below illustrates the total return to shareholders (share price appreciation plus dividend) for the several years that our management team has been in place. These have been years of steady improvement, and 2004 has been a particularly noteworthy one. I hope you will agree that we have delivered on our goal to provide value to you.

We thank you for the opportunity to be stewards of your investment and for your continued confidence in our strategic direction.

WHAT DO YOU SEE?

This year's report asks, "What Do You See?" Despite the fact that the demand for our product, natural gas, grows only modestly, I see a world of possibilities in store for our company. This optimism is not merely a frame of mind, but is based on certain fundamentals about the business. I've listed them below, with a short explanation of each that gives some context to our 2005 goals.

There is always room for improvement. Even though most of our operating and financial metrics (e.g., cost/customer, customers/employee, cost/new meter, EBIT/customer) are in the first quartile of industry benchmarks, there are many additional technology and business process improvements we can adopt to raise our performance. These include rollout of global positioning systems in all our vehicles; work management software to automate the flow of marketing, design, construction and maintenance of our facilities; use of our enterprise resource program to retire obsolete business systems of newly acquired utilities; and full deployment of our energy trading and risk management system in our asset management and retail marketing businesses. These platforms are generally not new. Rather, they are proven systems in use in general industry. Our goal must not be to settle for doing what other utilities do. Instead, we must adopt the business practices and systems used by leading-edge companies in the global economy.

Volatility in gas markets is not transitory. After several years of intensive drilling all over North America, most experts have concluded that there are limits to our geology and hence to the amount of deliverability we can attain at historical prices.

HISTORICAL TOTAL RETURN

As a nation, we are thrust into global energy markets in the competition for supplemental supplies — mainly in the form of liquefied natural gas (LNG). Availability and pricing of these cargoes will be irregular, at least until the worldwide market for LNG matures. Thus we can expect volatility in U.S. gas prices for some time to come. Consequently, we must develop plans to diversify our supplies, stabilize our rates, and realign our pipelines and contracts to reflect the new realities. But from a shareholder growth and value standpoint, volatility supports the profitability of our asset management business. Volatility also provides assurance that there will be demand for the wholesale storage capacity we own and operate — capacity that we intend to enhance and expand at Jefferson Island.

Peak demand grows significantly more quickly than average demand.

Despite record home ownership in our nation and record housing starts in our service territories, the demand for natural gas has grown only modestly. Even with multiple gas end uses in homes today, the quality of construction and more efficient appliances moderate demand. But on the coldest days of the year, demand is growing significantly faster than average use — two to three to five times faster, depending on the service territory. Peak demand grows more quickly because at extreme temperatures, gas use intensifies, regardless of appliance efficiency. Because large interstate pipelines do not specialize in meeting peak-day requirements, we must identify supplemental resources to meet the 10 to 20 coldest days of the year. This is why our Pivotal propane project is so important in Virginia and why we are expanding and reconfiguring the operations of our Macon, Georgia LNG plant. These facilities provide cost-effective peaking service. Moreover, they are good, solid investments as well.

We won't pay too much to expand our business through acquisition.

Two years ago, I wrote that AGL Resources had gained a reputation for the deals we hadn't done rather than the ones we did do. Dick O'Brien, our chief financial officer, and I have had numerous discussions about the combination of valuation and cost savings that would provide meaningful new earnings for our shareholders. We walked away from a number of opportunities in the intervening period. But this year, the alignment of valuation and synergies manifested itself and we purchased both NUI and Jefferson Island at competitive valuations. In each case, we have work to do to make them best in class, but we also have a clear line of sight to earnings from these investments. Investors obviously agree, as we were able to issue $332 million in equity to finance these acquisitions without any adverse effect on the prevailing share price or any anticipation of earnings dilution.

WHAT WILL YOU SEE IN 2005?

First, *we will integrate our new assets decisively,* driving the inherent value we identified in them to our bottom line. We will simultaneously seek to improve all our business metrics in our pre-existing businesses as well.

Second, with our enlarged business platform, *we intend to earn a national reputation for customer service excellence.* Providing a superior customer experience is part of what sets great companies apart. When gas customers think of great service, we want them to think of our companies. We will work actively to introduce service standards in New Jersey and Florida as well as continue their refinement in other states.

Third, *we will accelerate the pace at which we implement new technology* to achieve our "one company – one way" vision. Standardized business practices promote scalability and efficiency and reduce operating risk. Standardization runs contrary to individualized operating practices — and we reject the latter paradigm as part of the legacy of a fragmented industry.

Fourth, *we will achieve industry-leading levels of disclosure, transparency and collaboration with regulators* in the states in which we serve. In the wake of corporate scandals, we have seen how quickly trust can diminish. We want to be the kind of company that regulators would choose if they could, based on open books and records and solid operating performance. We can only do this through constant engagement and by voluntarily submitting to scrutiny, transparency and measurement against objective standards. We are fortunate to operate in positive regulatory climates, with responsive policymakers. Nevertheless, in various proceedings this year, you will see us redouble our efforts to earn the right to provide comprehensive service in our franchise areas.

WHAT WILL YOU SEE?

Some of our investors have asked us when we will run out of opportunities. The answer is not any time soon. As we tell our team, there is no end game here. There is no destination which, upon reaching it, we can say, "we're here, now we're done." The ethos of a competitive global economy forces us to keep looking for opportunities, to perform better with each passing year and to continue to innovate — for our customers and for our shareholders. 2005 should be an interesting year. Stay with us on the journey. We think you'll like what you see.

Paula Rosput Reynolds

Paula Rosput Reynolds
Chairman, President and Chief Executive Officer
AGL Resources Inc.
March 3, 2005

2005 GOALS

Integrate our acquisitions and meet the performance expectations of our value-oriented investors.

Establish a national reputation for excellent customer service by investing in systems, processes and people.

Accelerate the pace of technology adoption and business process improvement to achieve our "one company" vision.

Elevate our public policy profile with leading levels of transparency and collaboration to facilitate the adoption of our regulatory and business framework.

FINANCIALS

SELECTED FINANCIAL DATA

Selected financial data about us is set forth in the table below. We derived the data in the tables from our audited financial statements. You should read the data in the table in conjunction with our consolidated financial statements and related notes. On September 30, 2001, our Board of Directors elected to change our fiscal year end from September 30 to December 31, effective October 1, 2001. We refer to the three months ended December 31, 2001 as the "Transition Period" in the table below.

We acquired Jefferson Island Storage & Hub, LLC (Jefferson Island) on October 1, 2004, and NUI Corporation (NUI) on November 30, 2004. As a result, our results of operations for 2004 include three months of the acquired operations of Jefferson Island and one month of the acquired operations of NUI. Pursuant to FIN 46R, which we adopted in January 2004, we consolidated all of SouthStar's accounts with our subsidiaries' accounts as of January 1, 2004.

Dollars and shares in millions, except per share amounts	2004	2003	2002	Transition Period	2001	2000
Income statement						
Operating revenues	**$1,832**	$ 983	$ 877	$ 204	$ 946	$ 608
Operating expenses						
Cost of gas	**994**	339	268	49	327	112
Operation and maintenance	**377**	283	274	68	267	248
Depreciation and amortization	**99**	91	89	23	100	83
Taxes other than income taxes	**30**	28	29	6	33	27
Total operating expenses	**1,500**	741	660	146	727	470
Gain on sale of Caroline Street campus	**—**	16	—	—	—	—
Operating income	**332**	258	217	58	219	138
Equity in earnings of SouthStar	**—**	46	27	4	14	6
Gain on sale of Utilipro Inc.	**—**	—	—	—	11	—
Gain on propane transaction	**—**	—	—	—	—	13
Other income (loss)	**—**	2	3	1	(7)	9
Donation to private foundation	**—**	(8)	—	—	—	—
Minority interest	**(18)**	—	—	—	—	—
Interest expense	**(71)**	(75)	(86)	(24)	(98)	(58)
Earnings before income taxes	**243**	223	161	39	139	108
Income taxes	**90**	87	58	14	50	37
Income before cumulative effect of change in accounting principle	**153**	136	103	25	89	71
Cumulative effect of change in accounting principle, net of $5 in income taxes	**—**	(8)	—	—	—	—
Net income	**$ 153**	$ 128	$ 103	$ 25	$ 89	$ 71
Common stock data						
Weighted average shares outstanding — basic	**66.3**	63.1	56.1	55.3	54.5	55.2
Weighted average shares outstanding — fully diluted	**67.0**	63.7	56.6	55.6	54.9	55.2
Earnings per share — basic	**$ 2.30**	$ 2.03	$ 1.84	$ 0.45	$ 1.63	$ 1.29
Earnings per share — fully diluted	**$ 2.28**	$ 2.01	$ 1.82	$ 0.45	$ 1.62	$ 1.29
Dividends per share	**$ 1.15**	$ 1.11	$ 1.08	$ 0.27	$ 1.08	$ 1.08
Dividend payout ratio	**50%**	55%	59%	60%	66%	84%
Book value per share[1,2]	**$18.04**	$14.66	$12.52	$12.41	$12.20	$11.49
Market value per share[1]	**$33.24**	$29.10	$24.30	$23.02	$19.97	$20.08
Balance sheet data[1]						
Total assets	**$5,640**	$3,972	$3,742	$3,454	$3,368	$2,588
Long-term liabilities and deferred credits	**682**	647	702	671	711	768
Capitalization						
Long-term debt (excluding current portion)	**1,623**	956	994	1,015	1,065	664
Common shareholders' equity	**1,385**	945	710	690	671	621
Total capitalization	**$3,008**	$1,901	$1,704	$1,705	$1,736	$1,285
Financial ratios[1]						
Capitalization						
Long-term debt	**54%**	50%	58%	60%	61%	52%
Common shareholders' equity	**46**	50	42	40	39	48
Total	**100%**	100%	100%	100%	100%	100%
Return on average common shareholders' equity	**13.1%**	15.5%	14.7%	14.6%	13.8%	11.1%

[1] As of the last day of the respective fiscal period. [2] Common shareholders' equity divided by total outstanding common shares.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

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

Forward-looking statements involve matters that are not historical facts, such as projections of our financial performance, management's goals and strategies for our business and assumptions regarding the foregoing. Because these statements involve anticipated events or conditions, forward-looking statements often include words such as "anticipate," "assume," "can," "could," "estimate," "expect," "forecast," "indicate," "intend," "may," "plan," "predict," "project," "seek," "should," "target," "will," "would" or similar expressions. For example, in this "Management's Discussion and Analysis of Financial Condition and Results of Operations" section and elsewhere in this report, we have forward-looking statements regarding our expectations for

- revenue growth
- operating income growth
- cash flows from operations
- operating expense growth
- capital expenditures
- our business strategies and goals
- our potential for growth and profitability
- our ability to integrate our recent and future acquisitions
- trends in our business and industries
- developments in accounting standards

Do not unduly rely on forward-looking statements. They represent our expectations about the future and are not guarantees. Our expectations are based on currently available competitive, financial and economic data along with our operating plans. While we believe that our expectations are reasonable in view of the currently available information, our expectations are subject to future events, risks and uncertainties, and there are several factors — many beyond our control — that could cause results to differ significantly from our expectations. We caution readers that, in addition to the important factors described elsewhere in this report, the factors set forth in "Risk Factors," among others, could cause our business, results of operations or financial condition in 2005 and thereafter to differ significantly from those expressed in any forward-looking statements. There also may be other factors not described in this report that could cause results to differ significantly from our expectations.

Forward-looking statements are only as of the date they are made, and we do not undertake any obligation to update these statements to reflect subsequent changes.

OVERVIEW

NATURE OF OUR BUSINESS

We are an energy services holding company whose principal business is the distribution of natural gas in six states — Florida, Georgia, Maryland, New Jersey, Tennessee and Virginia. Our six utilities serve more than 2.2 million end-use customers, making us the largest distributor of natural gas in the eastern United States based on number of customers. We are also involved in various related businesses, including retail natural gas marketing to end-use customers in Georgia; natural gas asset management and related logistics activities for our own utilities as well as for other nonaffiliated companies; natural gas storage arbitrage and related activities; operation of high-deliverability underground natural gas storage; and construction and operation of telecommunications conduit and fiber infrastructure within select metropolitan areas. We manage these businesses through three operating segments — distribution operations, wholesale services and energy investments — and a nonoperating corporate segment.

The distribution operations segment is the largest component of our business and is comprehensively regulated by regulatory agencies in six states. These agencies approve rates that are designed to provide us the opportunity to generate revenues; to recover the cost of natural gas delivered to our customers and our fixed and variable costs such as depreciation, interest, maintenance and overhead costs; and to earn a reasonable return for our shareholders. With the exception of Atlanta Gas Light Company (Atlanta Gas Light), our largest utility franchise, the earnings of our regulated utilities are weather-sensitive to varying degrees. Although various regulatory mechanisms provide a reasonable opportunity to recover our fixed costs regardless of volumes sold, the effect of weather manifests itself in terms of higher earnings during periods of colder weather and lower earnings with warmer weather. Our Georgia retail marketing business, SouthStar Energy Services LLC (SouthStar), also is weather-sensitive, and uses a variety of hedging strategies to mitigate potential weather impacts. All of our utilities and SouthStar face competition in the residential and commercial customer markets based on customer preferences for natural gas compared with other energy products and the price of those products relative to that of natural gas.

We derived approximately 96% of our earnings before interest and taxes (EBIT) during the year ended December 31, 2004 from our regulated natural gas distribution business and from the sale of natural gas to end-use customers in Georgia by SouthStar, which is part of our energy investments segment. This statistic is significant because it represents the portion of our earnings that results directly from the underlying business of supplying natural gas to retail customers. Although SouthStar is not subject to the same regulatory framework as our utilities, it is an integral part of the retail framework for providing gas service to end-use customers in the state of Georgia. For more information regarding our measurement of EBIT and the items it excludes from operating income and net income, see "Results of Operations—AGL Resources."

The remaining 4% of our EBIT was principally derived from businesses that are complementary to our natural gas distribution business. We engage in natural gas asset management and operation of high-deliverability natural gas underground storage as adjunct activities to our utility franchises. These businesses allow us to be opportunistic in capturing incremental value at wholesale, provide us with deepened business insight about natural gas market dynamics and facilitate our ability, in the case of asset management, to provide transparency to regulators as to how that value can be captured to benefit our utility customers through sharing arrangements. Given the volatile and changing nature of the natural gas resource base in North America and globally, we believe that participation in these related businesses strengthens our business vitality.

OUR COMPETITIVE STRENGTHS

We believe our competitive strengths have enabled us to grow our business profitably and create significant shareholder value. These strengths include:

Regulated distribution assets located in growing geographic regions

Our operations are primarily concentrated along the east coast of the United States, from Florida to New Jersey. We operate primarily urban utility franchises in growing metropolitan areas where we can deploy technology to improve service delivery and manage costs.

We believe the population growth and resulting expansion in business and construction activity in many of the areas we serve should result in increased demand for natural gas and related infrastructure for the foreseeable future.

Demonstrated track record of performance through superior execution

We continue to focus our efforts on generating significant incremental earnings improvements from each of our businesses. We have been successful in achieving this goal in the past through a combination of business growth and controlling or reducing our operating expenses. We achieved these improvements to our operations in part through the implementation of best practices in our businesses, including increased investments in enterprise technology, workforce automation and business process modernization.

Proven ability to acquire and integrate natural gas assets that add significant incremental earnings

We take a disciplined approach to identifying strategic natural gas assets that support our long-term business plan. For example, our November 2004 purchase of NUI Corporation (NUI), a New Jersey–based energy holding company with natural gas distribution operations in New Jersey, Florida, Maryland and Virginia, provides us an opportunity to leverage and strengthen one of our core competencies—the efficient, low-cost operation of urban natural gas franchises. The disparity between NUI's pre-acquisition utility operating metrics and cost structure and those of our other utilities provides us an opportunity to achieve significant improvements in NUI's business in 2005 and beyond. In addition, our acquisition in October 2004 of the natural gas storage assets of Jefferson Island Storage & Hub, LLC (Jefferson Island), as discussed below, added immediate incremental earnings to our business and, given the possibilities for expansion, should provide a stable earnings stream going forward.

BUSINESS ACCOMPLISHMENTS IN 2004

- We increased net income 20% to $153 million and fully diluted earnings per share 13% to $2.28 from prior-year amounts. In addition to improvements in our base distribution business and energy investments businesses, we were able to capture additional incremental net income in the wholesale natural gas market through our Sequent Energy Management, L.P. (Sequent) asset management, producer services and storage arbitrage activities.
- We strengthened our position as a leading operator of natural gas utility assets in the eastern United States by acquiring NUI.

- We acquired Jefferson Island, a high-deliverability salt dome gas storage facility in Louisiana, which allows us to migrate into the wholesale market and capitalize on the growing market of utility and large industrial customers, producers, financial intermediaries and marketers who compete to hold firm capacity rights to store natural gas. For more information on our acquisitions on NUI and Jefferson Island, see Note 2.
- We announced our plan to acquire 250 miles of intrastate pipeline in our Georgia service area from Southern Natural Gas (Southern Natural), a subsidiary of El Paso Corporation, which should close in the second quarter of 2005. We expect this acquisition to allow us to, over time, undertake economical reconfiguration of our Georgia transmission grid, integrating gas flows from the Gulf Coast, imported liquefied natural gas (LNG) and our own market-area LNG.
- We began construction of a propane-air facility in Virginia that will provide needed peak-day demand protection for the customers of our Virginia Natural Gas, Inc. (Virginia Natural Gas) utility.
- We continued to support a strong balance sheet by issuing 11.04 million shares of AGL Resources common stock in November 2004, raising net proceeds of $332 million primarily to fund the NUI and Jefferson Island acquisitions.
- We increased our dividend 7% for the third consecutive year. If the current amount per quarter of $0.31 per share is in effect for all of 2005, our indicated annual rate would be $1.24 per share.

AREAS OF STRATEGIC FOCUS IN 2005

Our business strategy is focused on effectively managing our gas distribution operations; optimizing our return on our assets; selectively growing our gas distribution businesses through acquisitions; and developing our portfolio of closely related, unregulated businesses with an emphasis on risk management and earnings visibility. Key elements of our strategy include:

Enhance the value and growth potential of our regulated utility operations

We will seek to enhance the value and growth of our existing utility assets by managing our capital spending effectively; pursuing customer growth opportunities in each of our service areas; establishing a national reputation for excellent customer service by investing in systems, processes and people; working to achieve authorized returns in each jurisdiction and, in those jurisdictions where we have performance-based rates, sharing the benefits with our customers; and maintaining earnings and rate stability through regulatory compacts that fairly balance the interests of customers and shareholders.

Rapidly integrate the NUI assets and achieve the resulting strategic benefits

We are working to integrate NUI's assets into our portfolio of businesses and to provide the associated benefits to our customers and shareholders. Our integration plan includes applying enterprise-wide technology solutions and business processes that are designed to improve the key business metrics we track on a regular basis and bringing NUI's operations to a level of operational and service efficiency comparable to that of our other utility businesses. As part of this process, we also will evaluate certain NUI businesses for possible divestiture, consistent with our philosophy of exiting businesses that do not support our long-term strategy.

Focus on maintaining strong, investment-grade profile and high level of liquidity

We will continue to maintain a disciplined approach to capital spending and improving operating margins to optimize cash flow generation. Additionally, we seek to reduce in the near term our ratio of total debt to total capitalization in order to strengthen our balance sheet and allow us to respond to the capital needs of our operating businesses. We understand the importance of maintaining strong, investment-grade credit ratings in order to support our operating and investment needs, and we intend to execute our strategy in a way that enhances our ability to maintain or improve those ratings.

Achieve appropriate regulatory outcomes that support stable utility earnings

We currently are involved in regulatory proceedings in Georgia and Tennessee. In Georgia, Atlanta Gas Light's rate case is in process and expected to be completed by April 30, 2005. In Tennessee, we anticipate receiving a final ruling on our appeal of a 2004 Chattanooga Gas Company (Chattanooga Gas) rate case in the first quarter. Achieving favorable outcomes in these cases, and any other formal or informal regulatory proceedings in which we may be involved, is integral to the achievement of our earnings targets.

Selectively evaluate the acquisition of natural gas assets

We will selectively examine and evaluate the acquisition of natural gas distribution, gas pipeline or other gas-related assets. Our acquisition criteria include the ability to generate operational synergies, strategic fit relative to our core competencies, value from near-term earnings contributions and adequate returns on invested capital, while maintaining or improving our investment-grade credit ratings.

Selectively expand our other energy businesses

We intend to continue to expand our wholesale services and natural gas storage businesses to provide disciplined incremental earnings growth for shareholders. Sequent intends to continue providing credits to our utility customers through effective management of our affiliated utility assets. In our asset management business, we intend to grow our business with nonaffiliated third parties, as well as the services we provide to our affiliated utilities, by providing producers with markets for their gas commodity; providing end-users with gas supply, storage and asset management options; and arbitraging pipeline and storage assets across various gas markets and time horizons. However, we intend to continue protecting our earnings-at-risk by maintaining our commitment to limited open-position and credit risks and by providing transparency and visibility to regulators under our asset management agreements. As our portfolio of assets and our ability to store more physical gas inventory grow, the volatility of reported earnings from this business may increase. In our high-deliverability underground storage business, we will seek to expand the operating capabilities of our existing facilities to provide more flexible and valuable injection and withdrawal capabilities for our customers. Pivotal Jefferson Island Storage & Hub LLC (Pivotal Jefferson Island) is currently expanding its compression capabilities to increase the number of times a customer can inject and withdraw natural gas. We will complete and begin operation of our propane peaking facility, and look for additional opportunities to provide economical peaking services in the regions in which our utilities operate.

Acquire and retain natural gas customers

We continue to focus significant efforts in our distribution operations business on improving our net customer growth trends, despite the industry-wide challenges of rising prices for natural gas and competition from alternative fuels, declining natural gas usage per customer and declining regional load factors. In each of our utility service areas, we will continue to implement programs aimed at emphasizing natural gas as the fuel of choice for customers and maximizing the use of natural gas through a variety of promotional opportunities. We also are focused on similar customer growth initiatives in our SouthStar retail marketing business in Georgia. In addition, we continue to improve the credit quality of our customers in the retail marketing business and will use those techniques to improve credit and collections activities within our regulated utilities.

Continue to improve revenue and cash flow stability

We have taken a number of actions in recent years to promote more stable and predictable revenues and cash flows in each of our business segments, as well as to moderate the effects of variable factors, such as weather and natural gas prices on our business results. Some of the improvements we have initiated include performance-based ratemaking treatment in Georgia; weather normalization adjustment programs in Virginia and Tennessee; more efficient cost management and cash recovery from our environmental response cost (ERC) program in Georgia; and reduced credit losses from our retail marketing business. We estimate that in 2005 our spending for property, plant and equipment will be $276 million compared to $264 million in 2004. Our capital expenditures should decrease in successive years by reduced spending related to the pipeline replacement program (PRP), a mandated regulatory program that has required significant expenditures. We expect to improve our net cash flow, which should provide enhanced financial flexibility around business investment opportunities and potentially a return of capital to investors to provide additional shareholder value.

REGULATORY ENVIRONMENT

We are subject to the rate regulation and accounting requirements of various state and federal regulatory agencies in the jurisdictions in which we do business. We are committed to working cooperatively and constructively with the regulatory agencies in these states, as well as with federal regulatory agencies in a way that benefits our customers, shareholders and other stakeholders. We believe the dynamic energy environment in which we operate demands that we maintain an open, respectful and ongoing dialogue with these agencies. This posture is the best way to ensure we are working toward common solutions to the many issues our industry faces. These issues include the changing nature of resource availability, pricing volatility, price levels and their effect on economic development in our service territories, the likelihood of increased importation of LNG and the need for reasonably priced alternatives for our customers to meet their rapidly growing peak demands. For more information regarding pending federal and state regulatory matters, see "Results of Operations — Distribution Operations" and "Results of Operations — Wholesale Services."

TECHNOLOGY INITIATIVES

We continue to make progress with regard to several of our strategic technology initiatives. During the third quarter of 2004, we implemented new technological tools that enable marketers of natural gas in Georgia (Marketers) to create and input service orders directly into Atlanta Gas Light's systems, eliminating the need for duplicate data entry or three-way calls between the customer, Marketers and our customer call center. This system allowed for a reduction in the number of customer service representatives servicing Marketers in our call center, while providing enhanced service to Marketers. It also allowed us to further develop our strategy for the replacement of our customer information system, which should result in less capital investment over time than previously estimated.

In addition, we implemented our new energy trading and risk management (ETRM) system at Sequent in the fourth quarter of 2004. The ETRM system is designed to enhance internal controls and provide additional transparency into the activities of Sequent's business. We also anticipate the system will enable Sequent to continue to grow its commercial business without significant growth in support staff.

INTERNAL CONTROLS

Section 404 of the Sarbanes-Oxley Act of 2002 (SOX 404) Compliance

SOX 404 and related rules of the SEC require management of public companies to assess the effectiveness of the company's internal controls over financial reporting as of the end of each fiscal year. This includes disclosure of any material weaknesses in the company's internal controls over financial reporting that have been identified by management. In addition, SOX 404 requires the company's independent auditor to attest to and report on management's annual assessment of the company's internal controls over financial reporting. We have documented, tested and assessed our systems of internal control over financial reporting, as required under SOX 404 and Public Accounting Oversight Board Standard No. 2, "An Audit of Internal Control Over Financial Reporting Performed in Conjunction With An Audit of Financial Statements" (Standard No. 2), which was adopted in June 2004, to provide the basis for management's report and our independent auditors' attestation on the effectiveness of our internal control over financial reporting as of December 31, 2004. We estimate our Sox 404 compliance costs in 2004 were approximately $8 million, which include $5 million of external costs.

There are three levels of possible deficiencies in our internal controls over financial reporting that can be identified during our assessment phase, which are

- an internal control deficiency, which exists when the design or the operation of a control does not allow management or employees, in the normal course of performing their functions, to prevent or detect misstatements on a timely basis
- a significant deficiency, which exists when an internal control deficiency or a combination of internal controls deficiencies adversely affects our ability to initiate, authorize, record, process or report financial data in accordance with accounting principles generally accepted in the United States of America (GAAP) such that there is a more-than-remote likelihood that a misstatement of the annual or interim financial statements that is more than inconsequential will not be prevented or detected
- a material weakness, which exists when a significant deficiency or a combination of significant deficiencies results in a more-than-remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected

As a result, our assessment could result in two possible outcomes at our reporting date:

- We could conclude that our internal controls over financial reporting were designed and were operating effectively, or
- We could conclude that our internal controls over financial reporting were not properly designed or did not operate effectively. A material weakness that exists at the reporting date would require our assessment to be that our internal controls over financial reporting are not effective, and we would be required to disclose such material weaknesses.

Our independent auditor is now required to issue three opinions annually, beginning with our 2004 consolidated financial statements. First, the auditor must evaluate and opine regarding the process by which we assessed the effectiveness of our internal controls over financial reporting. A second opinion must be issued as to the effectiveness of our internal controls over financial reporting. Finally, the independent auditor must issue an opinion, as is normally done, as to whether our consolidated financial statements are fairly presented, in all material respects.

The scope of our assessment of our internal controls over financial reporting included all of our consolidated entities except those falling under NUI, which we acquired on November 30, 2004, and Jefferson Island, which we acquired on October 1, 2004. In accordance with the SEC's published guidance, we excluded these entities from our assessment as they were acquired late in the year, and it was not possible to conduct our assessment between the date of acquisition and the end of the year. SEC rules require that we complete our assessment of the internal control over financial reporting of these entities within one year from the date of acquisition.

We have completed the assessment of the effectiveness of our internal controls over financial reporting as of December 31, 2004, and have concluded that our controls are operating effectively. Our report on internal control over financial reporting and our independent auditors' reports are included following the notes to the financial statements.

NUI Internal Control Weaknesses

NUI's external and internal auditors performed audits during NUI's fiscal 2003 and 2004 years that identified material weaknesses in NUI's internal controls. These weaknesses were previously discussed in NUI's filings with the SEC. In March 2004, additional internal control issues and deficiencies were identified in the focused audit of NUI that was conducted at the request of the New Jersey Board of Public Utilities (NJBPU). These deficiencies resulted in a material weakness in internal controls over NUI's financial reporting process and also resulted in a need for NUI to restate certain of its financial statements. The internal control deficiencies reported by NUI that were identified by NUI's external and internal auditors included, but were not limited to, the following:

- General ledger cash account balances were not being reconciled to the bank statements.
- General ledger account analyses were not being consistently performed.
- A listing of debt covenants was not being maintained.
- Comprehensive and formalized accounting and financial reporting policies and procedures did not exist.
- Instances were noted where management lacked certain technical accounting and tax expertise that resulted in accounting errors.
- The flow of accounting information between business units and corporate accounting was not timely or formalized.
- Accounts payable invoice processing procedures needed to be improved.
- A formal plan and implementation timetable needed to be developed to address compliance with the certification requirements of SOX 404.
- The contract review process was not formally documented, and appropriate procedures had not been developed to ensure timely review of contracts for accounting implications.
- There was a lack of adherence to policies and procedures for travel and entertainment expense reimbursements and procurement card expenditures.
- The payroll timekeeping and tracking process was manual in nature and prone to errors.
- Information technology had a number of areas where formal, documented policies and procedures had not been developed.

The focused audit conducted at the request of the NJBPU revealed the following accounting concerns and weaknesses:

- inappropriate and inaccurate treatment of intercompany payable and receivable balances
- inappropriate use of a common cash pool
- lack of a formal cash management agreement
- weaknesses in internal controls for accounts payable and receivable
- lack of formal or appropriate policies and procedures in certain accounting functions
- the need to audit procedures for fixed asset and continuing property records functions

To address the deficiencies in its internal controls and procedures noted above, NUI expanded its internal controls and procedures to include the additional analysis and other postclosing procedures described below. The company

- provided comprehensive in-house training in early fiscal 2004 covering the financial reporting process and internal accounting controls, including NUI's written accounting policies and procedures and a policy on disclosure controls, to individuals who participate in the preparation of the company's financial statements and required disclosures
- conducted meetings in which NUI's President and CEO, Vice President and CFO, General Counsel and Secretary reviewed and discussed accounting and operational issues to ensure completeness and accuracy of disclosures in NUI's SEC filings
- requested that NUI's in-house counsel and key financial and operational personnel provide information regarding any known commitments and contingencies that may have financial statement and/or disclosure implications
- obtained internal certifications from key accounting and operational personnel indicating that they reviewed drafts of NUI's SEC filings for completeness and accuracy
- conducted formal meetings, led by NUI's Corporate Controller with participation of key accounting personnel (prior to closing the books of account and filing required reports), to identify and resolve accounting and disclosure issues
- prepared and distributed to participants involved in the preparation and review of NUI's SEC filings a detailed time schedule outlining key dates and responsibilities for the preparation of financial information and required disclosures
- completed an audit disclosure checklist to ensure all disclosures required by GAAP and applicable securities laws and regulations were properly addressed

- assembled supporting documentation for disclosures made in its SEC filings
- retained external counsel to review drafts of its SEC filings to assist management in ensuring compliance with SEC rules and regulations
- created documentation, including flowcharts and formal written policies and procedures of NUI's financial reporting process, to assist management with its responsibility to ensure key internal accounting controls are identified and addressed
- distributed a business ethics policy to all employees requesting their acknowledgment that they received, read and complied with the ethics policy
- conducted internal audits to evaluate internal accounting controls of key business functions

We have initiated our efforts to assess the systems of internal control related to NUI's business to comply with the requirements of both Sections 302 and 404 of the Sarbanes-Oxley Act of 2002. We believe that material deficiencies in internal controls discussed above related to the NUI business persist and that we are required to address and resolve these deficiencies. Our integration plans with respect to the NUI businesses include the integration and conversion of NUI's accounting systems and internal control processes into our accounting systems and internal control processes, the majority of which we expect to complete during the first quarter of 2005. In addition, we have incorporated the NUI businesses into our disclosure control processes, which include the same or similar activities to those undertaken by NUI management described above, as well as other procedures, in our closing and financial reporting process.

RESULTS OF OPERATIONS

AGL RESOURCES

We acquired Jefferson Island on October 1, 2004 and NUI on November 30, 2004. As a result, our results of operations for 2004 include three months of the acquired operations of Jefferson Island and one month of the acquired operations of NUI. Pursuant to Financial Accounting Standards Board (FASB) Interpretation No. 46, "Consolidation of Variable Interest Entities," as revised (FIN 46R), which we adopted in January 2004, we consolidated all of SouthStar's accounts with our subsidiaries' accounts as of January 1, 2004. We recorded Piedmont Natural Gas Company, Inc.'s (Piedmont) portion of SouthStar's earnings as a minority interest in our statements of consolidated income and Piedmont's portion of SouthStar's contributed capital as a minority interest on our consolidated balance sheet. We eliminated any intercompany profits between segments.

Revenues

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

A significant portion of our operations is subject to variability associated with changes in commodity prices and seasonal fluctuations. During the heating season, which is primarily from November through March, natural gas usage and operating revenues are higher since generally more customers will be connected to our distribution systems and natural gas usage is higher in periods of colder weather than in periods of warmer weather. Additionally, commodity prices tend to be higher in colder months. Our nonutility businesses principally use physical and financial arrangements to economically hedge the risks associated with seasonal fluctuations and changing commodity prices. Certain hedging and trading activities may require cash deposits to satisfy margin requirements. In addition, because these economic hedges do not generally qualify for hedge accounting treatment, our reported earnings for the wholesale services and energy investments segments reflect changes in the fair value of certain derivatives; these values may change significantly from period to period.

Operating Margin and EBIT

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

Our operating margin and EBIT are not measures that are considered to be calculated in accordance with GAAP. You should not consider operating margin or EBIT an alternative to, or a more meaningful indicator of, our operating performance than operating income or net income as determined in accordance with GAAP. In addition, our operating margin or EBIT measures may not be comparable to a similarly titled measure of another company. The following are reconciliations of our operating margin and EBIT to operating income and net income, and other consolidated financial information for the years ended December 31, 2004, 2003 and 2002.

In millions, except per share amounts	2004	2003	2002
Operating revenues	**$1,832**	$ 983	$ 877
Cost of gas	**994**	339	268
Operating margin	**838**	644	609
Operating expenses			
Operation and maintenance	**377**	283	274
Depreciation and amortization	**99**	91	89
Taxes other than income taxes	**30**	28	29
Total operating expenses	**506**	402	392
Gain on sale of Caroline Street campus	**—**	16	—
Operating income	**332**	258	217
Other income	**—**	40	30
Minority interest	**(18)**	—	—
EBIT	**314**	298	247
Interest expense	**71**	75	86
Earnings before income taxes	**243**	223	161
Income taxes	**90**	87	58
Income before cumulative effect of change in accounting principle	**153**	136	103
Cumulative effect of change in accounting principle	**—**	(8)	—
Net income	**$ 153**	$ 128	$ 103
Basic earnings per common share			
Income before cumulative effect of change in accounting principle	**$ 2.30**	$ 2.15	$1.84
Cumulative effect of change in accounting principle	**—**	(0.12)	—
Basic earnings per common share	**$ 2.30**	$ 2.03	$1.84
Fully diluted earnings per common share			
Income before cumulative effect of change in accounting principle	**$ 2.28**	$ 2.13	$1.82
Cumulative effect of change in accounting principle	**—**	(0.12)	—
Fully diluted earnings per common share	**$ 2.28**	$ 2.01	$1.82
Weighted average number of common shares outstanding			
Basic	**66.3**	63.1	56.1
Fully diluted	**67.0**	63.7	56.6

2004 Compared to 2003

Our earnings per share and net income for 2004 were higher than the prior year due to stronger contributions from our wholesale services business, SouthStar and the acquisitions of NUI and Jefferson Island. The following table provides a summary of certain items that impacted 2004 earnings.

In millions	Increase (Decrease) in 2004 Operating Income (Before Taxes)
Accelerated recognition of margins associated with Sequent storage positions originally were anticipated to be liquidated in the first quarter of 2005	$ 5
Asset sales in the second quarter of 2004 for a residential and retail property in Savannah, Georgia which resulted in a $2 million contribution to EBIT and the sale of our remaining investment units in U.S. Propane LP (US Propane)	3
Change in Atlanta Gas Light's property taxes as a result of revised estimates and intangible property tax assessment	3
Contributions to the AGL Resources Private Foundation Inc. and for energy assistance by our subsidiary SouthStar	(3)

The distribution operations segment's EBIT for 2004 was $247 million, equal to 2003 results. For comparison purposes, however, the distribution operations segment's EBIT in 2004 increased by $13 million, after excluding the effect of a net $13 million pretax gain on the sale of company property and a related charitable contribution in 2003. In addition, 2004 EBIT includes a $7 million contribution from NUI.

Operating margins of the distribution operations segment improved by $42 million or 7%, primarily as a result of the acquisition of NUI ($25 million) and an approximately 2% increase in the total number of average connected customers at Atlanta Gas Light, Chattanooga Gas and Virginia Natural Gas. Operating expenses increased $29 million or 8% in 2004 relative to 2003, primarily as a result of NUI ($19 million) and increased costs related to information technology projects, regulatory activities (including Sarbanes-Oxley compliance) and depreciation expense, offset by decreased bad debt expense and a decrease in costs associated with postretirement benefits.

The wholesale services segment contributed $24 million in EBIT in 2004 compared with $20 million in 2003. The $4 million increase is primarily the result of unusually strong fourth-quarter 2004 results, reflecting the accelerated recognition of margins associated with storage positions that originally were anticipated to be liquidated in the first quarter of 2005. The accelerated margin recognition resulted in $5 million of operating income in the fourth quarter that otherwise would have been recognized in the first quarter of 2005. Primarily as a result of the decline in forward gas prices at the end of December 2004, and the positive mark-to-market impact that decline had on the futures contracts Sequent utilizes to economically hedge its storage positions, approximately $18 million or 75% of Sequent's full-year EBIT contribution was generated in the fourth quarter of 2004.

Sequent also continued to increase its volumes and business transaction activity in 2004. Full-year volumes increased 20%, from 1.75 billion cubic feet (Bcf) per day in 2003 to 2.10 Bcf per day in 2004. New peaking and third-party asset management transactions also contributed to strong results for the year. Sequent's operating expenses for 2004 were $29 million compared with $20 million in 2003. The increase was due primarily to increased personnel and increased costs associated with the implementation of a new energy trading and risk management system and Sarbanes-Oxley 404 compliance.

The energy investments segment contributed EBIT of $59 million in 2004, a 37% increase over the segment's $43 million contribution in 2003. The primary driver of this segment's results was the performance of SouthStar, which contributed $53 million in EBIT in 2004 compared with $46 million in 2003. The improved results at SouthStar mainly reflected higher commodity margins and decreased bad debt expense during the year. Energy investments' EBIT contribution increased due to higher contributions from AGL Networks LLC (AGL Networks) and the acquisition of Jefferson Island in October 2004.

The corporate segment EBIT contribution decreased by $4 million to $(16) million in 2004, primarily the result of costs associated with information technology projects, SOX 404 compliance and merger- and acquisition-related expenses.

Interest expense for 2004 was $71 million, which was $4 million lower than in 2003. A favorable interest rate environment and the issuance of lower-interest long-term debt combined to lower the company's interest expense in 2004 relative to the previous year. The increase of $19 million in average debt outstanding for 2004 compared to 2003 was due to additional debt incurred as a result of the acquisitions of NUI and Jefferson Island.

Dollars in millions	2004	2003	2004 vs. 2003
Total interest expense	**$ 71**	$ 75	$ (4)
Average debt outstanding[1]	**1,274**	1,255	19
Average rate	**5.6%**	6.0%	(0.4)%

[1] Daily average of all outstanding debt.

Based on variable-rate debt outstanding at December 31, 2004, a 100 basis point change in market interest rates from 3.1% to 4.1% would result in a change in annual pretax interest expense of $5 million. We anticipate that our interest expense in 2005 will be higher than in 2004 due to the following:

- higher projected short-term interest rates based on higher 2005 London Interbank Offered Rate (LIBOR) rates
- higher debt balances and higher interest rates from 2004 and 2005 on debt issued for the acquisitions of NUI and Jefferson Island

The increase in income tax expense of $3 million or 3% for 2004 compared to 2003 reflected $8 million of additional income taxes due to higher corporate earnings year-over-year, offset by a $5 million decrease in income taxes due to a decrease in the effective tax rate from 39% in 2003 to 37% in 2004. The decline in the effective tax rate was primarily the result of income tax adjustments recorded in the third quarter of 2004 in connection with our annual comparison of our filed tax returns to the related income tax accruals. We expect our effective tax rate for the year ending December 31, 2005 to be higher due to the favorable adjustments recorded in 2004 and the higher state income tax rate that will be applicable to earnings from Elizabethtown Gas Company (Elizabethtown Gas) in New Jersey.

As a result of the company's 11 million share equity offering in November 2004, earnings results for the year are based on weighted average shares outstanding of 66.3 million, while 2003 results were based on weighted average shares outstanding of 63.1 million. Currently, we have approximately 76.9 million shares outstanding.

2003 Compared to 2002

Net income increased $25 million or 24% 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 million, increased 4% to $234 million from $225 million in 2002 due to higher operating margins, an increase in the number of connected customers and increased pipeline replacement revenue in 2003. Wholesale services contributed $20 million in EBIT compared to $9 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 million in EBIT compared to $24 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 an income-sharing issue with Piedmont. Our corporate segment's expenses decreased primarily as a result of favorable interest expense and lower average debt balances. The 7 million share increase in our weighted average shares outstanding was a result of our 6.4 million share equity offering in February 2003.

The following table shows the impact of the 2003 sale of our Caroline Street campus and the related donation to the private foundation:

In millions	Distribution Operations	Corporate	Consolidated
Gain (loss) on sale of Caroline Street campus	$21	$ (5)	$16
Donation to private foundation	(8)	—	(8)
EBIT	13	(5)	8
Income taxes			(3)
Net income			$ 5

The decrease in interest expense of $11 million or 13% for 2003 compared to 2002 was a result of lower average debt balances, as shown in the following table, due primarily to the proceeds generated from our public offering of 6.4 million shares of common stock in February 2003; repayment of Medium-Term notes, which had higher rates than our bond issuance in July 2003; the benefits of our interest rate swaps; and lower interest rates on commercial paper borrowings.

Dollars in millions	2003	2002	2003 vs. 2002
Total interest expense	$ 75	$ 86	$ (11)
Average debt outstanding[1]	1,255	1,412	(157)
Average rate	6.0%	6.1%	(0.1)%

[1] Daily average of all outstanding debt.

The increase in income tax expense of $29 million or 50% for 2003 compared to 2002 was primarily due to the increase in earnings before income taxes of $62 million or 39% and an increase in our effective tax rate from 36% in 2002 to 39% 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.

Consolidation of SouthStar

Below are our unaudited pro-forma condensed consolidated balance sheet and statement of income, presented as if SouthStar's balances were consolidated with our subsidiaries' accounts as of December 31, 2003. This pro-forma presentation is a non-GAAP presentation; however, we believe this pro-forma presentation is useful to the readers of our financial statements since it presents our financial statements for prior years on the same basis as 2004 following our consolidation of SouthStar pursuant to our adoption of FIN 46R. These unaudited pro-forma amounts are presented only for comparative purposes. The eliminations include intercompany eliminations, our investment in SouthStar, SouthStar's capitalization and our equity in earnings from SouthStar.

Pro-forma condensed consolidated balance sheet December 31, 2003

In millions	As Reported	SouthStar	Eliminations	(Unaudited) Pro-forma
Current assets	$ 742	$174	$ (11)	$ 905
Property, plant and equipment	2,352	2	—	2,354
Deferred debits and other assets[1]	878	—	(71)	807
Total assets	$3,972	$176	$ (82)	$4,066
Current liabilities	$1,048	$ 75	$ (11)	$1,112
Accumulated deferred income taxes	376	—	—	376
Long-term liabilities	569	—	—	569
Deferred credits	78	—	—	78
Minority interest[2]	—	—	30	30
Capitalization	1,901	101	(101)	1,901
Total liabilities and capitalization	$3,972	$176	$ (82)	$4,066

[1] Our investment in SouthStar was $71 million.

[2] Minority interest adjusts our balance sheet to reflect Piedmont's portion of SouthStar's contributed capital.

Pro-forma condensed consolidated statement of income for the year ended December 31, 2003

In millions	As Reported	SouthStar[1]	Eliminations	(Unaudited) Pro-forma
Operating revenues	$983	$746	$(169)	$1,560
Operating expenses				
Cost of gas	339	622	(169)	792
Operation and maintenance expenses	283	60	—	343
Depreciation and amortization	91	1	—	92
Taxes other than income	28	—	—	28
Total operating expenses	741	683	(169)	1,255
Gain on sale of Caroline Street campus	16	—	—	16
Operating income	258	63	—	321
Equity earnings from SouthStar	46	—	(46)	—
Donation to private foundation	(8)	—	—	(8)
Other income	2	—	—	2
Interest expense	(75)	—	—	(75)
Minority interest in income of consolidated subsidiary[2]	—	—	(17)	(17)
Earnings before income taxes	223	63	(63)	223
Income taxes	(87)	—	—	(87)
Income before cumulative effect of change in accounting principle	$136	$ 63	$ (63)	$ 136

[1] Includes 100% of SouthStar's revenues and expenses for comparisons of SouthStar's consolidation in 2004.

[2] Minority interest adjusts our earnings to reflect our 80% share of SouthStar's earnings, less Dynegy Inc.'s 20% share of SouthStar's income prior to February 18, 2003.

Pro-forma condensed consolidated statement of income for the year ended December 31, 2002

In millions	As Reported	SouthStar[1]	Eliminations	(Unaudited) Pro-forma
Operating revenues	$877	$630	$(171)	$1,336
Operating expenses				
Cost of gas	268	515	(171)	612
Operation and maintenance expenses	274	72	—	346
Depreciation and amortization	89	2	—	91
Taxes other than income	29	—	—	29
Total operating expenses	660	589	(171)	1,078
Operating income	217	41	—	258
Equity earnings from SouthStar	27	—	(27)	—
Other income	3	1	—	4
Interest expense	(86)	—	—	(86)
Minority interest in income of consolidated subsidiary[2]	—	—	(15)	(15)
Earnings before income taxes	161	42	(42)	161
Income taxes	(58)	—	—	(58)
Net income	$103	$ 42	$ (42)	$ 103

[1] Includes 100% of SouthStar's revenues and expenses for comparisons of SouthStar's consolidation in 2004.

[2] Minority interest adjusts our earnings to reflect our 50% share of SouthStar's earnings.

Segment Information

Operating revenues, operating margin and EBIT information for each of our segments are contained in the following table for the years ended December 31, 2004, 2003 and 2002:

In millions	Operating Revenues	Operating Margin	EBIT
2004			
Distribution operations	**$1,111**	**$641**	**$247**
Wholesale services	**54**	**53**	**24**
Energy investments	**852**	**145**	**59**
Corporate[1]	**(185)**	**(1)**	**(16)**
Consolidated	**$1,832**	**$838**	**$314**
2003			
Distribution operations	$ 936	$599	$247
Wholesale services	41	40	20
Energy investments	6	5	43
Corporate	—	—	(12)
Consolidated	$ 983	$644	$298
2002			
Distribution operations	$ 852	$585	$225
Wholesale services	23	23	9
Energy investments	2	1	24
Corporate	—	—	(11)
Consolidated	$ 877	$609	$247

[1] Includes the elimination of intercompany revenues.

DISTRIBUTION OPERATIONS

Distribution operations includes our natural gas local distribution utility companies, which construct, manage and maintain natural gas pipelines and distribution facilities and serve more than 2.2 million end-use customers. Distribution operations' revenues contributed 61% of our consolidated revenues for 2004, 95% for 2003 and 97% for 2002. The decrease of 34% in the contribution of distribution operations' revenues from 2003 is due to the impact of our consolidation of SouthStar in 2004. The following table provides operational information for our larger utilities. The daily capacity represents total system capability and the storage capacity includes on-system LNG and propane volumes.

	Atlanta Gas Light	Elizabethtown Gas	Virginia Natural Gas	Florida Gas	Chattanooga Gas
Average end-use customers (in thousands)[1]	1,533	266	256	104	60
Daily capacity[2]	2.5	0.4	0.4	0.1	0.2
Storage capacity[2]	55.6	14.0	10.2	—	4.8
2004 peak-day demand[2]	1.8	0.4	0.3	0.04	0.1
Average monthly throughput[2]	19.8	5.0	2.9	0.8	1.4
Authorized return on rate base[3,4]	9.16%	7.95%	9.24%	7.36%	7.43%
Authorized return on equity[4]	10.0–12.0%	10.0%	10.0–11.4%	11.25%	10.2%
Authorized rate base % of equity[4]	47.0%	53.0%	52.4%	36.8%	35.5%
Estimated 2004 return on equity[4,5]	11.2%	5.2%	11.4%	6.6%	9.4%
Rate base included in estimated 2004 return of equity (in millions)[6,7]	$1,120	$397	$325	$125	$94

[1] Represents an average for 2004 except Elizabethtown Gas and Florida City Gas Company (Florida Gas) which are December 2004 amounts.

[2] In millions of dekatherms.

[3] The authorized return on rate base for Florida Gas includes a credit for deferred taxes that is considered a rate base deduction in all other jurisdictions.

[4] The authorized returns on rate base and equity along with authorized rate base % of equity for Chattanooga Gas are currently under reconsideration by the Tennessee Regulatory Authority (Tennessee Authority). The estimated 2004 return on equity for Chattanooga Gas is calculated consistent with the Tennessee Authority order that is under reconsideration.

[5] Estimate based on principles consistent with utility ratemaking in each jurisdiction. Returns are not consistent with GAAP returns.

[6] Based on 13-month average.

[7] Elizabethtown Gas is based on amounts filed in a 2002 rate case; however no specific level of rate base was authorized due to settlement by stipulation with NJBPU.

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

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 and oil and propane providers 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 desirability of natural gas heating versus alternative heating sources. 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. 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

In 2004, our distribution operations segment's customers grew by approximately 2%. However, in some of our service areas, primarily in Georgia, overall growth continues to be limited due to the number of customers who choose to leave our systems. We expect our customer growth to improve in the future through our efforts in new business and retention. These efforts include working to add residential customers with three or more appliances, multifamily complexes and high-value commercial customers that use natural gas for purposes other than space heating. In addition, we partner with numerous entities to market the benefits of gas appliances and to identify potential retention options early in the process for those customers who might consider leaving our franchise by converting to alternative fuels.

Our distribution operations utilities include:

Atlanta Gas Light is a natural gas local distribution utility with distribution systems and related facilities throughout Georgia. Atlanta Gas Light has approximately 6 Bcf of LNG storage capacity in three LNG plants to supplement the supply of natural gas during peak usage periods. Atlanta Gas Light is regulated by the Georgia Public Service Commission (Georgia Commission).

Prior to Georgia's 1997 Natural Gas Competition and Deregulation Act (Deregulation Act), which deregulated Georgia's natural gas market, Atlanta Gas Light was the supplier and seller of natural gas to its customers. Today Marketers — that is, marketers who are certificated by the Georgia Commission to sell retail natural gas in Georgia at rates and on terms approved by the Georgia Commission — sell natural gas to the end-use customers in Georgia and are handling customer billing functions. Atlanta Gas Light's role includes

- distributing natural gas for Marketers
- constructing, operating and maintaining the gas system infrastructure, including responding to customer service calls and leaks
- performing meter reading and maintaining underlying customer premise information for Marketers

Since 1998, a number of federal and state proceedings have addressed the role of Atlanta Gas Light in administering and assigning interstate assets to Marketers pursuant to the provisions of the Deregulation Act. In this role, Atlanta Gas Light is authorized to offer additional sales services pursuant to Georgia Commission–approved tariffs and to acquire and continue managing the interstate transportation and storage contracts that underlie the sales services provided to Marketers on its distribution system under Georgia Commission–approved tariffs.

Performance-based Rates Atlanta Gas Light's revenues are established pursuant to a three-year performance-based rate (PBR) plan that became effective May 1, 2002, with an authorized return on equity of 11%. The PBR plan also establishes an earnings band based on a return on equity of 10% to 12%, subject to certain adjustments, with three-quarters of any earnings above a 12% return on equity shared with Georgia customers and one-quarter retained by Atlanta Gas Light.

The Georgia Commission staff has reviewed the operation of the plan and Atlanta Gas Light's revenue requirement to determine whether base rates should be reset upon the expiration of the existing plan in April 2005. The Georgia Commission will then determine whether the plan should be discontinued, extended or otherwise modified.

In connection with this review, Atlanta Gas Light filed a general rate case request for a $26 million rate increase with the Georgia Commission. The request would continue the PBR plan and include a return on equity band of 10.2% to 12.2%. The Georgia Commission is scheduled to issue its decision on April 28, 2005, with any rate adjustments to be effective May 1, 2005. Any rate adjustments would be comprised of changes from May 1, 2002 and projected through April 30, 2005 related to depreciation expense, capital expenditures and various other operating expenses such as pipeline integrity costs mandated by federal regulations and changes in the property tax valuation method.

Pipeline Replacement Program (PRP) Pursuant to the Georgia Commission's revised procedural and scheduling order, Atlanta Gas Light's rate case filing included testimony on whether the PRP should be included in Atlanta Gas Light's base rates or whether the rider currently used for recovery of PRP expenses should be otherwise modified or discontinued. Atlanta Gas Light's testimony supported continuing the current PRP rider agreement. Including the PRP capital costs in base rates before the end of the program would result in a regulatory delay in recovery of our total unrecovered PRP regulatory asset of $361 million. This delay could require more frequent rate requests to fund the annual cost of PRP capital expenditures and resulting depreciation. In addition, the future loss of a recovery mechanism could impair the PRP regulatory asset. Any resulting impairment would reduce Atlanta Gas Light's earnings.

Straight-fixed-variable Rates Atlanta Gas Light's revenue is recognized under a straight-fixed-variable rate design, whereby Atlanta Gas Light charges rates to its customers based primarily on monthly fixed charges. This mechanism minimizes the seasonality of revenues since the fixed charge is not volumetric and the monthly charges are not set to be 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 Atlanta Gas Light's revenues since generally more customers will be connected in periods of colder weather than in periods of warmer weather.

Interstate Pipeline Acquisition Atlanta Gas Light has executed an agreement with Southern Natural, a subsidiary of El Paso Corporation, to acquire a portion of Southern Natural's interstate pipeline that runs from Macon, Georgia to the vicinity of Atlanta, Georgia. The transaction is valued at approximately $32 million. As part of the agreement, Atlanta Gas Light will extend certain existing Southern Natural transportation and storage contracts to ensure reliable delivery of natural gas into Georgia in return for the right to expand Atlanta Gas Light's system off of the purchased facilities. On January 19, 2005, the Federal Energy Regulatory Commission (FERC) approved the abandonment of Southern Natural's facilities to Atlanta Gas Light, thereby allowing the transaction to proceed to closing. We expect the Southern Natural transaction to close by April 30, 2005, subject to securing the remaining regulatory approvals.

Capacity Supply Plan In May 2004, Atlanta Gas Light and 8 of the 10 Marketers entered into a settlement that resolved matters related to a capacity supply plan that was required to be filed by Atlanta Gas Light in July 2004. As a result of the settlement, the parties filed a three-year capacity supply plan for the Georgia market with the Georgia Commission. In October 2004, we received reconsideration and approval by the Georgia Commission of the capacity supply plan, which includes, among other things:

- calculation of the design (peak) day requirements for the next three years
- purchase by Atlanta Gas Light of the above-described Southern Natural facilities and the recovery of those costs through the pending rate case
- construction of a pipeline from the Macon LNG facility to the purchased Southern Natural facilities
- extension of the Sequent peaking contract to March 2005
- approval of Sequent's current asset management contract for retained assets through March 1, 2006
- other tariff provisions

Elizabethtown Gas is a natural gas local distribution utility that we acquired with our NUI acquisition with distribution systems and related facilities in central and northwestern New Jersey. Elizabethtown Gas has an LNG storage and vaporization facility to supplement the supply of natural gas during peak usage periods. The facility has a daily capacity of 24,200 million cubic feet (Mcf) and storage capacity of 131,000 Mcf. Most of Elizabethtown Gas' customers are located in densely populated central New Jersey, where increases in the number of customers primarily result from conversions to gas heating from alternative forms of heating. In the northwest region of the state, customer additions are driven primarily by new construction. Elizabethtown Gas is regulated by the NJBPU.

On November 9, 2004, the NJBPU approved our acquisition of NUI and our agreement with the NJBPU's staff and certain third parties related to postclosing operations. This agreement provided, among other things, for

- a freeze of Elizabethtown Gas' base rates for five years, with earnings over an 11% return of equity to be shared with ratepayers in the fourth and fifth years
- Sequent to serve as asset manager for Elizabethtown Gas, beginning April 1, 2005, for a three-year term for an annual fixed-fee payment by Sequent to Elizabethtown Gas of $4 million
- new performance standards with respect to customer satisfaction, safety and reliability, with negotiations with the various interested parties of the applicable standards beginning in February 2005
- acceleration of the payment of the outstanding balances due on Elizabethtown Gas' $28 million refund to its ratepayers and a related $2 million penalty to the NJBPU
- a commitment to make $9 million available for the purpose of enhancing severance packages for certain employees located in New Jersey

Weather Normalization Elizabethtown Gas' tariff contains a weather normalization clause that is designed to help stabilize Elizabethtown Gas' results by increasing base rate amounts charged to customers when weather has been warmer than normal and decreasing amounts charged when weather is colder than normal. The weather normalization clause was renewed in October 2004 and is based on the 20-year average of weather conditions.

Virginia Natural Gas is a natural gas local distribution utility with distribution systems and related facilities in southeastern Virginia. Virginia Natural Gas 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. Virginia Natural Gas also has approximately 5 million gallons of propane storage capacity in its two propane facilities to supplement the supply of natural gas during peak usage periods. Virginia Natural Gas is regulated by the Virginia State Corporation Commission (Virginia Commission).

Weather Normalization Adjustment (WNA) On September 27, 2002, the Virginia Commission 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 winter weather is warmer than normal. In September 2004, Virginia Natural Gas received approval from the Virginia Commission to extend Virginia Natural Gas' WNA program for an additional two years with certain modifications to the existing program. The significant modifications include the removal of the commercial class of customers from the WNA program and the use of a rolling 30-year average to calculate the weather factor that is updated annually.

Propane-air Facility In June 2004, the Virginia Commission issued its final order authorizing the recovery by Virginia Natural Gas of all charges for the services of a new propane-air facility through Virginia Natural Gas' gas cost recovery mechanism. The approval is for an initial 10-year term, with the possibility of renewal thereafter for terms of 2 years subject to Virginia Commission approval. The facility will provide Virginia Natural Gas with 28,800 dekatherms (Dth) of propane air per day on a 10-day-per-year basis to more reliably serve its peaking needs.

Florida City Gas Company (Florida Gas) is a natural gas local distribution utility, acquired with our NUI acquisition. Florida Gas has distribution systems and related facilities in central and southern Florida. Florida Gas customers purchase gas primarily for heating water, drying clothes and cooking. Some customers, mainly in central Florida, also purchase gas to provide space heating during the winter season. Florida Gas is regulated by the Florida Public Service Commission (Florida Commission).

In January 2004, Florida Gas received approval from the Florida Commission to increase its base rates by approximately $7 million, effective February 23, 2004. The increase represents a portion of Florida Gas' request for a rate increase to cover the costs of investments in its customer service assets, system maintenance and growth, and increases in its operating expenses.

Chattanooga Gas is a natural gas local distribution utility with distribution systems and related facilities in the Chattanooga and Cleveland areas of Tennessee. Chattanooga Gas has approximately 1.2 Bcf of LNG storage capacity in its LNG plant. Included in the base rates charged by Chattanooga Gas is a weather normalization clause that allows for revenue to be recognized based on a factor derived from average temperatures over a 30-year period, which offsets the impact of unusually cold or warm weather on its operating income. Chattanooga Gas is regulated by the Tennessee Regulatory Authority (Tennessee Authority).

Base Rate Increase In January 2004, Chattanooga Gas filed a rate plan request with the Tennessee Authority for a total rate increase of approximately $5 million annually. The rate plan was filed to cover Chattanooga Gas' rising cost of providing natural gas to its customers. In May 2004, the Tennessee Authority suspended the increase until July 28, 2004 and subsequently deferred the decision to August 30, 2004. After its initial filing, Chattanooga Gas reduced its rate plan increase to approximately $4 million, primarily as a result of the February 2004 Tennessee Authority ruling discussed in "Purchased Gas Adjustment" below. Chattanooga Gas received a written order from the Tennessee Authority on October 20, 2004 that authorized new rates based on a 7.43% return on rate base for an increase in revenues of approximately $1 million annually. In November 2004, the Tennessee Authority granted Chattanooga Gas' motion for reconsideration of the rate increase and in December 2004 heard oral arguments on the issues of the appropriate capital structure and the return on equity to be used in setting Chattanooga Gas' rates. The Tennessee Authority has not yet issued its ruling after reconsideration.

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

Elkton Gas Company (Elkton Gas) is a natural gas local distribution utility that we acquired with our NUI acquisition. Elkton Gas has distribution systems and related facilities serving approximately 5,900 customers in Cecil County, Maryland. Elkton Gas customers are approximately 93% commercial and industrial and 7% residential. Elkton Gas' current rates were authorized in June 1992 by the Maryland Public Service Commission.

Virginia Gas Distribution Company is a natural gas local distribution utility that we acquired with our NUI acquisition. Virginia Gas Distribution Company services approximately 300 customers in franchised territories in the southwestern Virginia counties of Buchanan and Russell. Approximately 76% of its natural gas sales are to residential customers with its remaining sales to commercial and industrial customers. Virginia Gas Distribution Company is regulated by the Virginia Commission.

Results of Operations for our distribution operations segment for the years ended December 31, 2004, 2003 and 2002 are shown in the following table:

In millions	2004	2003	2002	2004 vs. 2003	2003 vs. 2002
Operating revenues	**$1,111**	$936	$852	$175	$84
Cost of gas	**470**	337	267	133	70
Operating margin	**641**	599	585	42	14
Operation and maintenance expenses	**286**	261	255	25	6
Depreciation and amortization	**85**	81	82	4	(1)
Taxes other than income	**24**	24	25	—	(1)
Total operating expenses	**395**	366	362	29	4
Gain on sale of Caroline Street campus	**—**	21	—	(21)	21
Operating income	**246**	254	223	(8)	31
Donation to private foundation	**—**	(8)	—	8	(8)
Other income	**1**	1	2	—	(1)
Total other (loss) income	**1**	(7)	2	8	(9)
EBIT	**$ 247**	$247	$225	$ —	$22
Metrics					
Average end-use customers (in thousands)[1]	**1,880**	1,838	1,824	2%	1%
Operation and maintenance expenses per customer	**$152**	$142	$140	7	1
EBIT per customer[2]	**$131**	$127	$123	3	3
Throughput (in millions of Dth)[1]					
Firm	**194**	190	182	2%	4%
Interruptible	**105**	109	124	(4)	(12)
Total	**299**	299	306	—%	(2)%
Heating degree days[3]:					
Florida[1]	**239**	—	—	n/a%	n/a%
Georgia	**2,589**	2,654	2,812	(2)	(6)
Maryland[1]	**860**	—	—	n/a	n/a
New Jersey[1]	**873**	—	—	n/a	n/a
Tennessee	**3,010**	3,168	3,052	(5)	4
Virginia	**3,214**	3,264	3,030	(2)	8

[1] Represents information only for December 2004 for the utilities acquired from NUI.

[2] Excludes the gain on the sale of our Caroline Street campus in 2003.

[3] We measure effects of weather on our businesses using "degree days." The measure of degree days for a given day is the difference between average daily actual temperature and 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.

2004 Compared to 2003

There was no change in the distribution operations segment's EBIT from 2003; however, the 2003 results included a gain of $21 million on the sale of our Caroline Street campus, offset by an $8 million donation to AGL Resources Private Foundation, Inc. Exclusive of the gain and donation, EBIT increased $13 million or 5% due to increased operating margin that was partially offset by increased operating expenses.

The increase in operating margin of $42 million or 7% from 2003 includes $17 million in combined increases at Atlanta Gas Light and Virginia Natural Gas. The increase in Atlanta Gas Light's operating margin was primarily from higher PRP revenue as a result of continued PRP capital spending, customer growth, higher customer usage and additional carrying charges from gas stored for Marketers due to a higher average cost of gas. The increase in Virginia Natural Gas' operating margin was primarily from customer growth. The acquisition of NUI added $25 million of operating margin primarily from NUI's December operations of Elizabethtown Gas and Florida Gas.

Operating expenses increased $29 million or 8% from 2003. This was due primarily to the addition of NUI operations for the month of December of $19 million. The remaining increase of $10 million was due to increases in the cost of outside services related to increased information technology services as a result of our ongoing implementation of a work management system, increased legal services due to increased regulatory activity and increased accounting services related to our implementation of SOX 404. Employee benefit and compensation expenses also increased primarily as a result of higher health care insurance costs and increased long-term compensation expenses. In addition, depreciation expenses increased primarily from new depreciation rates implemented for Virginia Natural Gas and increased assets at each utility. These increases were partially offset by a reduction in bad debt expenses, which was primarily due to a Tennessee Authority ruling that allows for recovery of the gas portion of accounts written off as uncollectible at Chattanooga Gas and increased collection efforts at both Chattanooga Gas and Virginia Natural Gas.

2003 Compared to 2002

EBIT increased $22 million or 10% for 2003 compared to 2002, primarily as a result of the gain, net of donation, of $13 million on the sale of our Caroline Street campus described above. Excluding the gain and donation, EBIT increased $9 million or 4% from increased operating margin, partially offset by increased operating expenses.

Operating margin increased $14 million or 2% from 2002. This was due primarily to an increased number of customers and a higher usage per degree day, of which Virginia Natural Gas contributed approximately $12 million. Atlanta Gas Light's PRP rider revenues increased $2 million, resulting from recovery of prior-year program expenses, and Atlanta Gas Light's carrying costs charged to Marketers for gas stored underground also contributed approximately $1 million due to higher storage volumes. Offsetting these increases was a reduction in Atlanta Gas Light's rates compared to prior year of $3 million for the first four months of 2003 due to the PBR settlement agreement with the Georgia Commission effective May 1, 2002. Chattanooga Gas' operating margin for 2003 was not materially different from 2002.

Operating expenses increased $4 million or 1% from 2002 due primarily to a $2 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 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 million Virginia Natural Gas regulatory asset write-off in 2003. These increases in operating expenses were partially offset by a $1 million decrease in depreciation expenses due to lower depreciation rates at Atlanta Gas Light for the first four months of 2003 as a result of the PBR settlement agreement with the Georgia Commission.

WHOLESALE SERVICES

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

Sequent provides its customers with natural gas from the major producing regions and market hubs primarily in the Eastern and Mid-Continental United States. Sequent also purchases transportation and storage capacity to meet its delivery requirements and customer obligations in the marketplace. Sequent's customers benefit from its logistics expertise and ability to deliver natural gas at prices that are advantageous relative to the other alternatives available to its end-use customers.

Asset Management Transactions

Our asset management customers include Atlanta Gas Light, Chattanooga Gas and Virginia Natural Gas, nonaffiliated utilities, municipal customers and industrial customers. These customers must contract for transportation and storage services to meet their demands, and they typically contract for these services on a 365-day basis even though they may only need a portion of 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 periods when they do not need them. We capture margin by optimizing the purchase, transportation, storage and sale of natural gas, and we typically either share profits with customers or pay them a fee for using their assets. On April 1, 2005, in connection with the acquisition of NUI, Sequent plans to commence asset management responsibilities for Elizabethtown Gas, Florida Gas and Elkton Gas. The contract terms are currently being negotiated.

We have reached the following agreements with the Virginia, Georgia and Tennessee state regulatory commissions to clarify Sequent's role as asset manager for our regulated utilities. Failure to renew these agreements on terms substantially similar to the current terms would, over time, have a significant impact on Sequent's EBIT if other customers and assets were not found to replace our utility asset management earnings.

- In November 2000, the Virginia Commission approved an asset management agreement that provides for a sharing of profits between Sequent and Virginia Natural Gas customers. This agreement expires in October 2005, unless Sequent, Virginia Natural Gas and the Virginia Commission agree to extend the contract. In December 2004, we contributed approximately $3 million to Virginia Natural Gas customers for the contract year November 2003 through October 2004. This contribution is being reflected as a reduction to customers' gas cost in 2005. We commenced discussions as to mutually acceptable terms under which this agreement could be extended.
- Various Georgia statutes require Sequent, as asset manager for Atlanta Gas Light, to share 90% of its earnings from capacity release transactions with Georgia's Universal Service Fund (USF). A December 2002 Georgia Commission order requires net margin earned by Sequent, for transactions involving Atlanta Gas Light assets other than capacity release, to be shared equally with the USF. Sequent operates under an asset management agreement with Atlanta Gas Light which is currently scheduled to expire in March 2006. In 2004, we contributed approximately $4 million to the USF based on profits earned in the last six months of 2003 and for the first six months of 2004.
- In June 2003, the Chattanooga Gas tariff was amended effective January 1, 2003 to require all net margin earned by Sequent for transactions involving Chattanooga Gas assets to be shared equally with Chattanooga Gas ratepayers. This agreement expires in April 2006 and is subject to automatic extensions unless specifically terminated by either party. In 2004, Sequent contributed approximately $1 million to Chattanooga Gas customers based on profits earned in 2003. This contribution was reflected as a reduction to customers' gas cost in 2004.

Transportation and Storage Transactions

In our wholesale marketing and risk management business, Sequent also contracts for 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 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 identifying the least-cost alternatives to serve our various markets. This enables us to capture geographical 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 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, principally in the Gulf Coast region. 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, among other things, the sale of peaking services, which includes receiving a fee from affiliated and nonaffiliated customers that guarantees that those customers will receive gas under peak conditions. Wholesale services incurs costs to support our obligations under these agreements, which will be reduced in whole or in part as the matching obligations expire. We will continue to seek new peaking transactions as well as work toward extending those that are set to expire.

Competition

Sequent competes for asset management business with other energy wholesalers, often through a competitive bidding process. Sequent has historically been successful in obtaining new asset management business by placing bids that were based primarily on the intrinsic value of the transaction, which is the difference in commodity prices between time periods or locations at the inception of the transaction.

There has been significant consolidation of energy wholesale operations, particularly among major gas producers. Financial institutions have also entered the marketplace. As a result, energy wholesalers have become increasingly willing to place bids for asset management transactions that are priced to capture market share. We expect this trend to continue in the near term, which could result in downward pressure on the volume of transactions and the related margins available in this portion of Sequent's business.

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 2004, we added personnel to focus specifically on these opportunities and continued to execute additional nonaffiliated asset management transactions. Our business territory now extends from Texas to Michigan and most other areas of the United States east of the Mississippi River.

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 has lengthened the average tenure of our portfolio to 25 months at December 31, 2004. At December 31, 2004, Sequent's longest-dated contract in its portfolio was 23 years and was obtained as part of the NUI acquisition. Excluding this contract, Sequent's portfolio contains transactions with contract terms ranging from one day to eight years. At December 31, 2004, Sequent's firm capacity commitments were:

In millions	Contract from NUI Acquisition	Other	Total
2005	$ 5	$8	$ 13
2006	5	2	7
2007 and thereafter	107	9	116

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 occasionally in the summer due to peak usage by power generators in 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 2005. Despite the consolidations within the industry, many entities are reluctant to turn over the marketing of their gas or their assets to a major competitor and may favor an independent wholesale services provider. In addition, many utilities are seeking incremental services to meet peak-day needs, which is an area of core expertise for Sequent.

We manage our business with limited open positions and limited value at risk (VaR). However, the rescission of Emerging Issues Task Force (EITF) Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 98-10), and our adoption of 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), in 2003 have increased earnings volatility in our reported results, as more fully discussed below. Given significant underlying volatility in gas commodity prices, we expect volatility in our earnings to continue.

Energy Marketing and Risk Management Activities

We accounted for derivative transactions in connection with our energy marketing activities on a fair value basis in accordance with Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133), and prior to 2003 we accounted for nonderivative energy and energy-related activities in accordance with EITF 98-10.

Under these methods, we recorded derivative 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 the EITF 02-03 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), which had the following effects:

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

As a result of our adoption of EITF 02-03:

- We recorded an adjustment to the carrying value of our nonderivative trading instruments (principally our storage capacity contracts) to zero, and we 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; we previously recorded them at fair value. This resulted in the cumulative effect of a change in accounting principle in our statement of consolidated income for the three months ended March 31, 2003 of $13 million ($8 million net of taxes), which resulted in a decrease of $13 million to our energy marketing and risk management assets, and a decrease in accumulated deferred income taxes of $5 million in our accompanying consolidated balance sheet.
- 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 all periods are shown net of costs associated with trading activities.

As shown in the table below, Sequent recorded net unrealized gains related to changes in the fair value of derivative instruments utilized in our energy marketing and risk management activities of $22 million during 2004, $1 million during 2003 and $4 million in 2002. The tables below illustrate the change in the net fair value of the derivative instruments and energy-trading contracts during 2004, 2003 and 2002 and provide details of the net fair value of contracts outstanding as of December 31, 2004. Sequent's storage positions are affected by price sensitivity in the New York Mercantile Exchange (NYMEX) average price.

In millions	2004	2003	2002
Net fair value of contracts outstanding at beginning of period	**$ (5)**	$ 7	$ 3
Cumulative effect of change in accounting principle	**—**	(13)	—
Net fair value of contracts outstanding at beginning of period, as adjusted	**(5)**	(6)	3
Contracts realized or otherwise settled during period	**11**	2	(5)
Change in net fair value of contract gains (losses)	**11**	(1)	9
Net fair value of new contracts entered into during period	**—**	—	—
Net fair value of contracts outstanding at end of period	**17**	(5)	7
Less net fair value of contracts outstanding at beginning of period, as adjusted for cumulative effect of change in accounting principle	**(5)**	(6)	3
Unrealized gain related to changes in the fair value of derivative instruments	**$22**	$ 1	$ 4

The sources of our net fair value at December 31, 2004 are as follows. 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.

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	$ 6	$ 1	$—	$—	$ 7
Prices provided by other external sources	$10	$—	$—	$—	$10

Mark-to-market Versus Lower of Average Cost or Market

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. We attempt to mitigate substantially all of our commodity price risk associated with our gas storage portfolio. We use derivative instruments to reduce the risk associated with future changes in the price of natural gas. We sell NYMEX futures contracts or other over-the-counter derivatives in forward months to substantially lock in the profit margin we will ultimately realize when the stored gas is actually sold.

Gas stored in inventory 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 profit margin is essentially unchanged from the date the transactions were consummated. Gas that we purchase and inject into storage is accounted for at the lower of average cost or market. The derivatives we use to mitigate commodity price risk are accounted for at fair value and marked to market each period. These differences in our accounting treatment, including the accrual basis for our gas storage inventory versus fair value accounting for the derivatives used to mitigate commodity price risk, can result in volatility in our reported earnings.

Earnings Volatility and Price Sensitivity

Over time, gains or losses on the sale of gas storage inventory will be offset by losses or gains on the derivatives used as hedges, resulting in the realization of the profit margin we expected when we entered into the transactions. Accounting differences cause Sequent's earnings on its gas storage positions to be affected by natural gas price changes, even though the economic profits remain essentially unchanged. Based on our storage positions at December 31, 2004, a $0.10 change in the forward NYMEX prices would result in a $0.3 million impact to Sequent's EBIT. As Sequent's storage position increases, its earnings volatility may also increase. For example, at year end, if all of Sequent's storage had been full, a $0.10 change in forward NYMEX prices would have resulted in a $0.7 million impact to its earnings.

In addition, if we were to value the gas inventory at fair value, with the change in fair value during the year reflected in earnings, Sequent's EBIT would have increased, net of applicable regulatory sharing, by $1 million and $3 million for the years ended December 31, 2004 and 2003. This is based on a difference between fair value and average cost of $2 million and $5 million for 2004 and 2003. 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 to determine fair value. The fair value is not reflected in the financial statements due to the accounting rules now in effect.

Storage Inventory Outlook

The NYMEX forward curve graph set forth below reflects the NYMEX natural gas prices as of September 30, 2004 and December 31, 2004 for the period of January 2005 through November 2005. The curve reflects the prices at which we could buy natural gas at the Henry Hub for delivery in the same time period. (Note: January 2005 futures expired on December 28, 2004; however, they are included as they coincide with the January storage withdrawals.) The Henry Hub, located in Louisiana, is the largest centralized point for natural gas spot and futures trading in the United States. NYMEX uses the Henry Hub as the point for delivery for its natural gas futures contracts. Many natural gas marketers also use the Henry Hub as their physical contract delivery point for their price benchmark for spot trades of natural gas.

The NYMEX forward curve graph also displays the significant decline in first quarter 2005 NYMEX prices experienced during the fourth quarter of 2004. As shown in the table following the graph, the majority of our inventory in storage as of December 31, 2004 was scheduled for withdrawal in early 2005. Since we have these NYMEX contracts in place, our original economic profit margin is unaffected. However, the decline in NYMEX prices during the fourth quarter of 2004 resulted in unrealized gains associated with our NYMEX contracts. During the fourth quarter of 2003, we experienced the opposite occurrence when NYMEX prices were increasing. In 2003, our near-term profits declined because our future-period hedges were at values lower than the prevailing market prices for the months in which we held the NYMEX contracts. See further discussions in "Results of Operations" below.

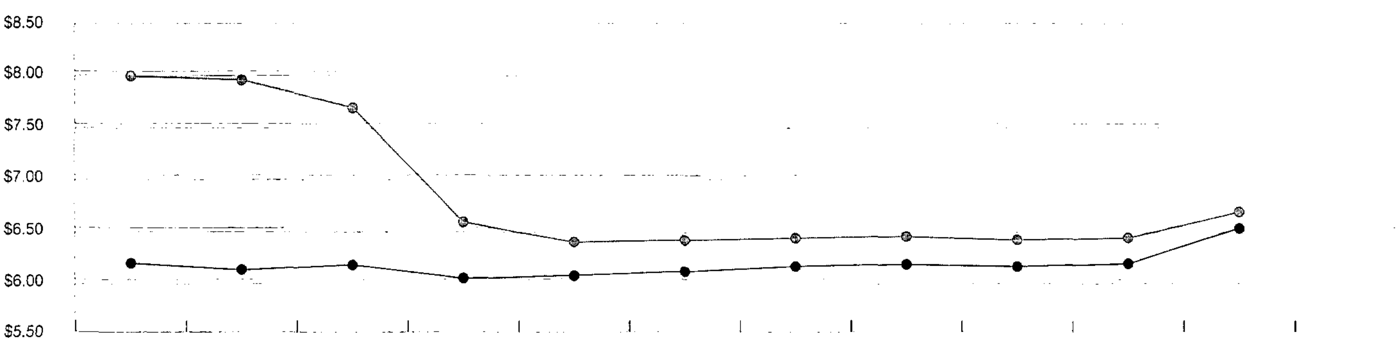
As shown in the table below, "Open Futures NYMEX Contracts" represents the volume in contract equivalents of the transactions we executed to lock in our storage inventory margin. Each contract equivalent represents 10,000 million British thermal units (MMBtu's). As of December 31, 2004, the expected withdrawal schedule of this inventory is reflected in items (B) and (C). At December 31, 2004, the weighted average cost of gas (WACOG) in salt dome storage was $5.83, and the WACOG for gas in reservoir storage was $5.88.

The table 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, 2004. Our current inventory level and pricing will result in gross margin of $1 million during 2005. This gross margin could change if we adjust our daily injection and withdrawal plans in response to changes in market conditions in future months.

NYMEX Forward Curve

□ September 2004

■ December 2004



	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Total
A	(21)	(105)	(286)	—	—	—	—	—	(2)	(10)	—	(424)
B	4	—	—	—	—	—	—	—	—	—	—	4
C	17	105	286	—	—	—	—	—	2	10	—	420
	21	105	286	—	—	—	—	—	2	10	—	424
D	$0.1	$0.2	$0.8	$—	$—	$—	$—	$—	$—	$—	$—	$1.1

A Open futures NYMEX contracts (short) long (in MMBtu).

B Physical salt dome withdrawal schedule (in MMBtu).

C Physical reservoir withdrawal schedule (in MMBtu).

D Expected gross margin, in millions, after regulatory sharing for withdrawal activity.

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 in which the pipeline allows the customer to park gas on or borrow gas from the pipeline in one period and reclaim gas from or repay gas to the pipeline in a subsequent period. The economics of these transactions are evaluated and price risks are managed similar to the way traditional reservoir and salt dome storage transactions are evaluated and managed. Sequent enters into forward NYMEX contracts to hedge its park and loan transactions. However, these transactions have elements that qualify as and must be accounted for as derivatives in accordance with SFAS 133.

Under SFAS 133, park and loan transactions are considered to be financing arrangements when the contracts contain volumes that are payable or repaid at determinable dates and at a specific 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) and represent the fair value of the derivatives in the consolidated balance sheet as "Inventories" and reflect the related changes in fair value in our statement of consolidated income.

The table below shows Sequent's park and loan volumes and expected gross margin from park and loans for the indicated periods. "Park and (loan) volumes" represents the contract equivalent for the volumes of our park and loan transactions as of December 31, 2004 that is not already accounted for at fair value. "Expected gross margin from park and loans" represents the gross margin from those transactions expected to be recognized in future periods based on the NYMEX forward curves at December 31, 2004.

In millions	Jan 2005	Feb 2005	Mar 2005	Apr 2005	May 2005	Jun 2005	Jul 2005	Total
Park and (loan) volumes (MMBtu)	(15)	12	6	—	15	(12)	(6)	—
Expected gross margin from park and (loans)	$(0.3)	$0.3	$0.1	—	—	—	—	$0.1

Credit Rating

Sequent has certain trade and credit contracts that have explicit rating trigger events in case of a credit rating downgrade. These rating triggers typically give counterparties the right to suspend or terminate credit if our credit ratings are downgraded to non-investment grade status. Under such circumstances, 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. If at December 31, 2004, our credit ratings had been downgraded to non-investment grade status, the required amounts to satisfy potential collateral demands under such agreements between Sequent and its counterparties would have totaled $20 million.

Results of Operations for our wholesale services segment for the years ended December 31, 2004, 2003 and 2002 are as follows:

In millions	**2004**	2003	2002	2004 vs. 2003	2003 vs. 2002
Operating revenues	**$54**	$41	$23	$13	$18
Cost of sales	**1**	1	—	—	1
Operating margin	**53**	40	23	13	17
Operation and maintenance expenses	**27**	20	13	7	7
Depreciation and amortization	**1**	—	—	1	—
Taxes other than income	**1**	—	1	1	(1)
Total operating expenses	**29**	20	14	9	6
Operating income	**24**	20	9	4	11
Other loss	**—**	—	—	—	—
EBIT	**$24**	$20	$ 9	$ 4	$11
Metrics					
Physical sales volumes (Bcf/day)	**2.10**	1.75	1.39	20%	26%

2004 Compared to 2003

EBIT increased $4 million or 20% from 2003 due to a $13 million increase in operating margin, partially offset by a $9 million increase in operating expenses.

Operating margin increased by $13 million or 33% primarily due to increased volatility during the fourth quarter of 2004, which provided Sequent with seasonal trading, marketing, origination and asset management opportunities in excess of those experienced during the prior year. Also contributing to the increase were advantageous transportation values to the Northeast and new peaking and third-party asset management transactions. Sequent's sales volumes for 2004 were 2.10 Bcf/day, a 20% increase from the prior year. This increase resulted primarily from the addition of new counterparties, increased presence in the Midwest and Northeast markets and continued growth in origination and asset management activities, as well as the business generated due to the market volatility experienced during the fourth quarter.

As a result of a decline in forward NYMEX prices, the 2004 results reflect the recognition of gains associated with the financial instruments used to hedge Sequent's inventory held in storage. If the forward NYMEX price in effect at December 1, 2004 had also been in effect at December 31, 2004, based on Sequent's storage positions at December 31, 2004, Sequent's reported EBIT would have been $19 million. At December 31, 2003, an increase in forward NYMEX prices resulted in the recognition of losses associated with inventory hedges.

Partially offsetting the improved fourth-quarter results was lower volatility during the second quarter of 2004 compared to the same period in 2003, which compressed Sequent's trading and marketing activities and the related margins within its transportation portfolio. In addition, Sequent's weighted average cost of natural gas stored in inventory was $5.06 per MMBtu during the first quarter of 2004 compared to $2.20 per MMBtu during the same period in 2003. This significant difference in cost resulted in reduced operating margins period over period.

Operating expenses increased by $9 million or 45% due primarily to additional salary expense as a result of an increase in the number of employees; additional costs for outside services related to the development and implementation of Sequent's ETRM system; the implementation of SOX 404; and increased corporate costs. In addition, 2004 operating expenses reflect depreciation associated with the recently implemented ETRM system.

2003 Compared to 2002

EBIT increased $11 million or 122% from 2002 primarily due to a $17 million increase in operating margin, offset by an increase of $6 million in operating expenses. The increase of $17 million or 74% in operating margin was due primarily to Sequent's optimization of various transportation and storage assets, mainly in the first quarter when natural gas prices were highly volatile. Sequent's physical sales volumes for 2003 increased 26% to 1.75 Bcf/day 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.

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 $13 million in realized income, offset by amounts shared with our affiliated local distribution companies 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. In the summer of 2002, 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 million or 43%, primarily due to a $3 million increase in corporate costs and a $3 million increase primarily due to personnel and outside consulting costs incurred while growing the business.

ENERGY INVESTMENTS

Our energy investments segment includes

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

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

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 on its market share, SouthStar is the largest retail marketer of natural gas in Georgia with average customers in 2004 in excess of 500,000. This represents a market share of approximately 36% as of December 31, 2004, which is consistent with its market share in 2003 and 2002.

Pivotal Jefferson Island, our wholly owned subsidiary, operates a storage and hub facility in Louisiana, approximately eight miles from the Henry Hub. We acquired the facility from American Electric Power in October 2004 for an adjusted price of $90 million, which included approximately $9 million of working gas inventory. We funded the acquisition with a portion of the net proceeds we received from our November 2004 common stock offering and debt borrowings.

The storage facility is regulated by the Louisiana Public Service Commission and by the FERC, the latter of which regulates the storage and transportation services. The facility consists of two salt dome gas storage caverns with 9.4 million Dth of total capacity and about 6.9 million Dth of working gas capacity. By increasing the maximum operating pressure, we can periodically increase the working gas capacity to approximately 7.4 million Dth. The facility has approximately 720,000 Dth/day withdrawal capacity and 240,000 Dth/day injection capacity. Pivotal Jefferson Island provides for storage and hub services through its direct connection to the Henry Hub via the Sabine Pipeline and its interconnection with other pipelines in the area. Pivotal Energy Development (Pivotal Development) is responsible for the day-to-day operation of the facility.

Pivotal Jefferson Island is fully subscribed for the 2004–2005 winter period. Beginning April 1, 2005, approximately 2.5 Bcf of capacity will become available. Marketing of this capacity is ongoing. Pivotal Jefferson Island intends to lease any unsubscribed capacity to one or more customers in 2005, for varying term lengths to create a portfolio of contracts for service. Pivotal Jefferson Island is currently expanding its compression capability to enhance the number of times a customer can inject and withdraw gas. We expect to complete this upgrade in the third quarter of 2005.

Pivotal Propane of Virginia, Inc. (Pivotal Propane), our wholly owned subsidiary, intends to complete in the first quarter of 2005 the construction of a propane-air facility in the Virginia Natural Gas service area to provide it with up to 28,800 Dth of propane air per day on a 10-day-per-year basis to serve Virginia Natural Gas' peaking needs. The cold storage tank foundation is complete and construction of the process facility is under way. We expect the plant to be initially available in the first quarter of 2005.

Virginia Gas Company is a natural gas storage, pipeline and distribution company with principal operations in southwestern Virginia. Virginia Gas Company, through its wholly owned subsidiary Virginia Gas Pipeline Co., owns and operates a 72-mile intrastate pipeline and operates two storage facilities, a high-deliverability salt cavern facility, Saltville Storage Inc. (Saltville Storage) in Saltville, Virginia, and a depleted reservoir facility in Early Grove, Virginia. Combined, the storage facilities have approximately 2.6 Bcf of working gas capacity. Virginia Gas Pipeline Co. also serves as construction and operations manager for our Saltville Storage joint venture described below.

Saltville Storage is a 50% member of Saltville Gas Storage Company, LLC, a joint venture formed in 2001 with a subsidiary of Duke Energy Corporation (Duke) to develop a high-deliverability natural gas storage facility in Saltville, Virginia and is accounted for under the equity method of accounting. Saltville Storage serves customers in the Mid-Atlantic region. Saltville Storage currently has approximately 1.8 Bcf of storage capacity and is planning an expansion to increase its storage capacity to 5.3 Bcf of working gas with deliverability of up to 500 million cubic feet per day. The expansion is expected to be completed in 2008. Saltville Storage connects to Duke's East Tennessee Natural Gas interstate system and its Patriot pipeline.

All of Virginia Gas Company's businesses are regulated by the Virginia Commission except Saltville Storage, which is regulated by the FERC. As such, Saltville Storage is required to construct and operate its facilities and provide service subject to FERC regulations.

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.

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 conduit and dark fiber footprints in Atlanta and Phoenix are unique continuous rings 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. US Propane owned all the general partnership interests, directly or indirectly, and approximately 25% of the limited partnership interests in Heritage Propane Partners, L.P. (Heritage Propane), a publicly traded marketer of propane. On January 20, 2004, we sold our general and limited partnership interests for $29 million and recognized a gain of $1 million, which we recorded in other income.

Results of Operations for our energy investments segment for the year ended December 31, 2004, and pro-forma results as if SouthStar's accounts were consolidated with our subsidiaries' accounts for the years ended December 31, 2003 and 2002 are set forth below. The unaudited pro-forma results are presented for comparative purposes as a result of our consolidation of SouthStar in 2004. This pro-forma basis is a non-GAAP presentation; however, we believe it is useful to the readers of our financial statements since it presents prior years' revenue and expenses on the same basis as 2004.

In 2003 and 2002, we recognized our portion of SouthStar's earnings of $46 million and $27 million, respectively, as equity earnings. The increase of $19 million or 70% was primarily due to resolution of an income sharing issue with Piedmont of $6 million, higher volumes and related operating margin, an additional 20% ownership interest (which contributed approximately $8 million), and lower bad debt and operating expenses.

In millions	2004	Pro-forma 2003	Pro-forma 2002	2004 vs. 2003	2003 vs. 2002
Operating revenues	**$852**	$752	$632	$100	$120
Cost of sales	**707**	622	515	85	107
Operating margin	**145**	130	117	15	13
Operation and maintenance expenses	**65**	69	80	(4)	(11)
Depreciation and amortization	**4**	2	2	2	—
Taxes other than income	**1**	1	—	—	1
Total operating expenses	**70**	72	82	(2)	(10)
Operating income	**75**	58	35	17	23
Other income	**2**	2	4	—	(2)
Minority interest	**(18)**	(17)	(15)	(1)	(2)
EBIT	**$ 59**	$ 43	$ 24	$ 16	$ 19
Metrics					
SouthStar					
Average customers (in thousands)	**533**	558	564	(4)%	(1)%
Market share in Georgia	**36%**	38%	38%	(5)%	—

2004 Compared to 2003

The increase in EBIT of $16 million or 37% for the year ended December 31, 2004 was primarily the result of increased EBIT of $7 million from SouthStar, EBIT of $3 million from Pivotal Jefferson Island and EBIT of $3 million from AGL Networks. The remaining increase of $3 million was from the sale of Heritage Propane and the sale of a residential and retail development property in Savannah, Georgia in the second quarter of 2004.

Operating margin for the year increased $15 million or 12% primarily as a result of operating margin increases at SouthStar of $8 million, the addition of Pivotal Jefferson Island's $4 million of operating margin and an operating margin increase at AGL Networks of $4 million. SouthStar's $8 million operating margin increase was a result of a $9 million increase due primarily to a lower commodity cost structure resulting from continued refinement of SouthStar's hedging strategies and a $3 million increase due to a full year of higher customer service charges from third-party providers. These increases were partially offset by a decrease of $2 million related to a one-time sale of stored gas in 2003 and a $2 million decrease in late payment fees due to an improved customer base. AGL Networks' increase was due to increased revenue from a variety of customers.

Operating expenses decreased by $2 million or 3% primarily due to $6 million lower bad debt expense as a result of ongoing active customer collection process improvements and increased quality of the customer base partially offset by a $5 million increase in corporate allocations and increased costs related to SOX 404 implementation. There was also a $1 million increase in minority interest as a result of higher SouthStar earnings in 2004 compared to 2003.

2003 Compared to 2002

The EBIT increase of $19 million or 79% was primarily due to increased EBIT at SouthStar and US Propane, offset by lower AGL Networks earnings.

Operating margin increased $13 million or 11% primarily due to $9 million from increased margin from SouthStar resulting from a $3 million one-time sale of storage, a $3 million increase from higher customer service charges and a $3 million increase in additional interruptible margin. There was also a $4 million increase in margin from AGL Networks due to a $3 million increase in monthly recurring contract revenues and a $2 million sales-type lease completed in the first quarter of 2003, partially offset by $1 million of feasibility fee income in 2002; no such fees were recognized in 2003.

The decrease in operating expenses of $10 million or 12% was due primarily to lower bad debt expense at SouthStar of $10 million as a result of improved delinquency processes and customer base and lower operating expenses from a reduction in customer care costs of $3 million. AGL Networks had a $3 million increase in operating expenses due primarily to business growth and higher corporate overhead costs. Other income decreased $2 million due primarily to a contract renewal payment of $2 million associated with the sale of Utilipro.

CORPORATE

Our corporate segment includes our nonoperating business units, including AGL Services and AGL Capital Corporation (AGL Capital). AGL Services 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 its commercial paper program, the issuance of various debt and hybrid securities, and other financing arrangements.

In August 2003, we formed Pivotal Development as an operating division within AGL Services. Pivotal Development coordinates, among our related operating segments, the development, construction or acquisition of gas-related assets in the regions our gas utilities serve or where their gas supply originates in order to extend our natural gas capabilities and improve system reliability while enhancing service to our customers in these areas. The focus of Pivotal Development's commercial activities is to improve the economics of system reliability and natural gas deliverability in these regions as well as acquire and operate natural gas assets that serve wholesale markets, such as underground storage.

We allocate substantially all AGL Services' 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 for our corporate segment for the years ended December 31, 2004, 2003 and 2002 are as follows:

In millions	2004	2003	2002	2004 vs. 2003	2003 vs. 2002
Payroll	**$ 48**	$ 48	$ 44	$—	$ 4
Benefits and incentives	**32**	32	38	—	(6)
Outside services	**29**	19	21	10	(2)
Taxes other than income	**4**	2	4	2	(2)
Other	**46**	44	35	2	9
Total operating expenses before allocations	**159**	145	142	14	3
Allocation to operating segments	**(147)**	(139)	(134)	(8)	(5)
Operating expenses	**12**	6	8	6	(2)
Loss on asset disposed of Caroline Street campus	**—**	(5)	—	5	(5)
Operating loss	**(12)**	(11)	(8)	(1)	(3)
Other losses	**(4)**	(1)	(3)	(3)	2
EBIT	**$ (16)**	$ (12)	$ (11)	$ (4)	$(1)

2004 Compared to 2003

The decrease in EBIT of $4 million or 33% for the year ended December 31, 2004 compared to the same period last year primarily was due to an increase in operating expenses of $6 million. The increase in operating expenses was primarily from increased outside services costs associated with software maintenance, licensing and implementation of our work management system project, higher costs due to our SOX 404 compliance efforts, merger and acquisition related expenses and expenses related to Pivotal Development's activities in 2004. The increase in operating expenses was offset by a loss of $5 million on the sale of our Caroline Street campus in 2003.

2003 Compared to 2002

The decrease in EBIT of $1 million or 9% for 2003 compared to 2002 was primarily the result of a loss of $5 million on the sale of our Caroline Street campus. The decrease was offset by decreased operating expenses of $2 million for 2003 compared to 2002.

The $2 million decrease in operating expenses was due to charges incurred in 2002 that were not incurred in 2003. In 2002, we recorded $6 million for the termination of an automated meter reading contract, $2 million for the write-off of capital costs related to a terminated risk management software implementation project and $2 million in employee severance costs. These decreases in operating expenses were offset by an $8 million increase in operating expenses consisting primarily of higher payroll due to the transfer of call center employees to AGL Services from distribution operations, and the increase in facility lease expense as a result of our headquarters move in 2003.

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 agreement (Credit Facility); and borrowings or stock issuances in the long-term capital markets to meet our capital and liquidity requirements. We believe these sources will be sufficient for our working capital needs, including the potentially significant volatility of working capital requirements of our wholesale services business, debt service obligations and scheduled capital expenditures for the foreseeable future. The relatively stable operating cash flows of our distribution operations business currently provide most of our cash flow from operations, and we anticipate this to continue in the future. However, 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, and we expect this to continue in the future. 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
- changes in wholesale prices and customer demand for our products and services
- 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 funding requirements
- changes in income tax laws
- margin requirements resulting from significant increases or decreases in our commodity prices
- operational risks

Our issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by state and federal regulatory bodies, including state public service commissions and the SEC. Furthermore, a substantial portion of our consolidated assets, earnings and cash flow is derived from the operation of regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to us is subject to regulation. On April 1, 2004, we received approval from the SEC, under the PUHCA, for the renewal of our financing authority to issue securities through April 2007. Our total cash and available liquidity under our Credit Facility at December 31, 2004 and 2003 is represented in the table below:

In millions	Dec 31, 2004	Dec 31, 2003
Unused availability under the Credit Facility	**$750**	$500
Cash and cash equivalents	**49**	17
Total cash and available liquidity under the Credit Facility	**$799**	$517

The increase in total cash and available liquidity under our Credit Facility of $282 million is due primarily to the amendment to our Credit Facility in September 2004 that, among other things, increased the facility size by $250 million, and additional cash from operations at December 31, 2004.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

We have incurred various contractual obligations and financial commitments in the normal course of our operations and financing activities. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease arrangements that are directly supported by related revenue-producing activities. We calculate any expense pension contributions using an actuarial method called the projected unit credit cost method, and as a result of our calculations, we expect to make a $1 million pension contribution in 2005. The table below illustrates our expected future contractual obligations:

		Payments Due Before December 31,			
In millions	Total	2005	2006 & 2007	2008 & 2009	2010 & Thereafter
Long-term debt[1,2]	$1,623	$ —	$ 2	$ 2	$1,619
Pipeline charges, storage capacity and gas supply[3,4]	1,051	258	262	179	352
Short-term debt[2]	334	334	—	—	—
PRP costs[5]	327	85	162	80	—
Operating leases[6]	170	27	39	29	75
ERC[5]	90	27	10	12	41
Commodity and transportation charges	20	19	1	—	—
Total	$3,615	$750	$476	$302	$2,087

[1] Includes $232 million of notes payable to Trusts redeemable in 2006 and 2007.

[2] Does not include the interest expense associated with the long-term and short-term debt.

[3] Charges recoverable through a PGA mechanism or alternatively billed to Marketers. Also includes demand charges associated with Sequent.

[4] A subsidiary of NUI entered into two 20-year agreements for the firm transportation and storage of natural gas during 2003 with the annual demand charges aggregate of approximately $5 million. As a result of our acquisition of NUI and in accordance with SFAS 141, "Business Combinations," the contracts were valued at fair value. The $38 million currently allocated to accrued pipeline demand charges on our consolidated balance sheets represent our estimate of the fair value of the acquired contracts. The liability will be amortized over the remaining lives of the contracts.

[5] Charges recoverable through rate rider mechanisms.

[6] 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.

SouthStar has natural gas purchase commitments related to the supply of minimum natural gas volumes to its customers. These commitments are priced on an index plus premium basis. At December 31, 2004, SouthStar had obligations under these arrangements for 11.2 Bcf for the year ended December 31, 2005. This obligation is not included in the above table. SouthStar also had capacity commitments related to the purchase of transportation rights on interstate pipelines.

We also have incurred various financial commitments in the normal course of business. Contingent financial commitments represent obligations that become payable only if certain predefined events occur, such as financial guarantees, and include the nature of the guarantee and the maximum potential amount of future payments that could be required of us as the guarantor. The following table illustrates our expected contingent financial commitments as of December 31, 2004:

		Commitments Due Before December 31,			
In millions	Total	2005	2006 & 2007	2008 & 2009	2010 & Thereafter
Guarantees[1]	$ 7	$ 7	$—	$—	$—
Standby letters of credit and performance/surety bonds	12	12	—	—	—
Total	$19	$19	$—	$—	$—

[1] We provide a guarantee on behalf of our affiliate, SouthStar. We guarantee 70% of SouthStar's obligations to Southern Natural under certain agreements between the parties up to a maximum of $7 million if SouthStar fails to make payment to Southern Natural. We have certain guarantees that are recorded on our consolidated balance sheet that would not cause any additional impact on our financial statements beyond what was already recorded.

CASH FLOW FROM OPERATING ACTIVITIES

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

We generate a large portion of our annual net income and subsequent increases in our accounts receivable in the first and fourth quarters due to significant volumes of natural gas delivered by distribution operations and SouthStar to our customers during the peak heating season. In addition, our natural gas inventories, which usually peak on November 1, are largely drawn down in the heating season and provide a source of cash as this asset is used to satisfy winter sales demand.

During this period, our accounts payable increases to reflect payments due to providers of the natural gas commodity and pipeline capacity. The value of the natural gas commodity can vary significantly from one period to the next as a result of the volatility in the price of natural gas. Our natural gas costs and deferred purchased natural gas costs due from or to our customers represent the difference between natural gas costs that have been paid to suppliers in the past and what has been collected from customers. These natural gas costs can cause significant variations in cash flows from period to period.

Our operating cash flow of $287 million for the year ended December 31, 2004 included SouthStar's operating cash flow of approximately $79 million as a result of our consolidation of SouthStar effective January 1, 2004. In 2003 and 2002, our operating cash flow only included amounts for cash distributions from SouthStar, consistent with the equity method of accounting. Excluding SouthStar, our cash flow from operations for the year ended December 31, 2004 was $208 million, an increase of $86 million from 2003. Year-to-year changes in our operating cash flow, excluding SouthStar, were primarily the result of increased earnings of $25 million and decreased spending for injection and purchase of natural gas inventories of $63 million.

Our cash flow from operations in 2003 was $122 million, a decrease of $164 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% compared to 2002. In addition, we made approximately $22 million in pension contributions in 2003 as a result of our continued efforts to fully fund our pension liability. This was offset by increased net income of $25 million and cash distributions received from SouthStar of $40 million.

CASH FLOW FROM INVESTING ACTIVITIES

Our cash used in investing activities in 2004 consisted primarily of property, plant and equipment (PP&E) expenditures and our acquisition of NUI for $116 million and Jefferson Island for $90 million. For more information on our acquisitions of NUI and Jefferson Island, see Note 2. In 2003, our investing activities included our cash payment of $20 million for the purchase of Dynegy's 20% interest in SouthStar. In 2002, we received $27 million in cash from SouthStar and US Propane. The following table provides additional information on our actual and estimated PP&E expenditures:

In millions	2005[1]	2004	2003	2002	2004 vs. 2003	2003 vs. 2002
Construction of distribution facilities	$ 87	**$ 64**	$ 60	$ 62	$ 4	$ (2)
Pipeline replacement program	85	**95**	45	48	50	(3)
Pivotal Propane plant	2	**29**	—	—	29	—
Telecommunications	5	**5**	8	28	(3)	(20)
Other	97	**71**	45	49	26	(4)
Total PP&E expenditures	$276	**$264**	$158	$187	$106	$(29)

[1] Estimated.

The increase of $106 million or 67% in PP&E expenditures for 2004 compared to 2003 was primarily due to increased PRP expenditures of $50 million and our construction of the Virginia propane plant by Pivotal Propane of $29 million. In addition, the increase was due to $9 million of expenditures for the construction of the Macon peaking pipeline, $7 million for the ETRM at Sequent, $3 million at Pivotal Jefferson Island and $3 million at SouthStar.

The decrease of $29 million or 15% in PP&E expenditures for 2003 compared to 2002 was primarily due to lower telecommunications expenditures of $20 million as a result of the completion of the metro Atlanta fiber network in 2002, a decrease in PRP expenditures of $3 million, and a decrease in construction of distribution facilities of $2 million associated with distribution operations.

For 2005, we estimate that our total PP&E expenditures will increase as a result of expenditures for the construction of distribution facilities of $23 million and acquisition and enhancement of the Southern Natural interstate pipeline for $38 million. Our expected increase in the construction of distribution facilities is primarily due to increased expenditures for renewals and the acquired NUI utilities.

Our PRP costs are expected to remain at current levels of spending, through the expected end of the program in 2008, 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. The PRP recoveries are recorded as revenues and are based on a formula that allows us to recover operation and maintenance costs in excess of those included in Atlanta Gas Light'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 cost recovery does not match the timing of when costs are incurred. As discussed earlier, Atlanta Gas Light's current rate case includes testimony on whether the PRP should be included in its base rates or whether the rider currently used for recovery of PRP expenses should be otherwise modified or discontinued.

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, distributions to minority interests, cash dividends on our common stock and the issuance of common stock. Our capitalization and financing strategy is intended to ensure that we are properly capitalized with the appropriate mix of equity and debt securities. This strategy includes active management by us of the percentage of total debt relative to our total capitalization, as well as the term and interest rate profile of our debt securities.

We also work to maintain or improve our credit ratings on our senior notes to effectively manage our existing financing costs and enhance our ability to raise additional capital on favorable terms. Factors we consider important in assessing our credit ratings include: our balance sheet leverage, capital spending, earnings, cash flow generation, available liquidity and overall business risks. We do not have any trigger events in our debt instruments that are tied to changes in our specified credit ratings or our stock price and have not entered into any transaction that would require us to issue equity based on credit ratings or other trigger events. As of February 2005, our senior unsecured debt ratings are BBB+ from Standard & Poor's Ratings Services (S&P), Baa1 from Moody's Investors Service (Moody's) and A- from Fitch Ratings (Fitch).

During 2004, no fundamental adverse shift occurred in our ratings profile; however, upon the announcement of our proposed acquisition of NUI, S&P placed our credit ratings on CreditWatch with negative implications, Moody's affirmed our ratings but changed its rating outlook to negative from stable, and Fitch placed our credit ratings on Rating Watch Negative. Since the closing of the acquisition, S&P removed us from CreditWatch and changed our outlook to negative; Fitch took us off Rating Watch Negative and affirmed our ratings with a stable outlook; and Moody's affirmed our ratings and kept the negative outlook. S&P and Moody's have indicated that the negative outlook is the result of the execution risks in integrating the NUI acquisition.

Our credit ratings may be subject to revision or withdrawal at any time by the assigning rating organization, and each rating should be evaluated independently of any other rating. We cannot ensure 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. If the rating agencies downgrade 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 decrease.

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

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

Dollars in millions	Dec 31, 2004		Dec 31, 2003	
Short-term debt	**$ 334**	**10%**	$ 383	16%
Long-term debt[1]	**1,623**	**48**	956	42
Total debt	**1,957**	**58**	1,339	58
Minority interest	**36**	**1**	—	—
Common shareholders' equity	**1,385**	**41**	945	42
Total capitalization	**$3,378**	**100%**	$2,285	100%

[1] Net of interest rate swaps.

Short-term Debt

Our short-term debt is composed of borrowings under our commercial paper program, Sequent's line of credit and SouthStar's line of credit. Our short-term debt financing generally increases between June and December because our payments for natural gas and pipeline capacity are generally made to suppliers prior to the collection of accounts receivable from our customers. In addition, we typically reduce short-term debt balances in the spring because a significant portion of our current assets are converted into cash at the end of the winter heating season.

In 2004, our $480 million of net short-term debt payments included the repayment of $500 million outstanding under NUI's credit facilities. Upon the repayment of the outstanding amounts, we terminated NUI's credit facilities.

Our commercial paper program is supported by our Credit Facility, which was amended on September 30, 2004. Under the terms of the amendment, the term of the Credit Facility was extended from May 26, 2007 to September 30, 2009. The aggregate principal amount available under the amended Credit Facility was increased from $500 million to $750 million, and our option to increase the aggregate cumulative principal amount available for borrowing on not more than one occasion during each calendar year was increased from $200 million to $250 million. As of December 31, 2004 and 2003, we had no outstanding borrowings under the Credit Facility. However, the availability of borrowings and unused availability under our Credit Facility is limited and subject to conditions specified within the Credit Facility, which we currently meet. These conditions include

- compliance with certain financial covenants
- the continued accuracy of representations and warranties contained in the agreement

Sequent uses its $25 million 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 1, 2005 and bears interest at the federal funds effective rate plus 0.5%. At December 31, 2004, the line of credit had an outstanding balance of $18 million.

SouthStar's $75 million line of credit provides the additional working capital needed to meet seasonal demands and is not guaranteed by us. The line of credit is secured by various percentages of its accounts receivable, unbilled revenue and inventory. The line of credit expires in April 2007 and bears interest at the prime rate and/or LIBOR plus a margin based on certain financial measures. At December 31, 2004, there were no amounts outstanding under this facility; the interest rate would have been 5.25% based on the prime rate.

Long-term Debt

In 2004, AGL Capital issued $250 million of 6% senior notes due October 2034 and $200 million of 4.95% senior notes due January 2015. We fully and unconditionally guarantee the senior notes. The proceeds from the issuance were used to refinance a portion of our outstanding short-term debt under our commercial paper program. During 2004, we also made $82 million in Medium-Term note payments using proceeds from the borrowings under our commercial paper program. Additionally, NUI Utilities, Inc., a wholly owned subsidiary of NUI had outstanding at closing $199 million of indebtedness pursuant to Gas Facility Revenue Bonds and $10 million in capital leases, of which $2 million is reflected as current. For more information on our long-term debt including the debt assumed from the NUI acquisition, see Note 8.

In 2003, we issued $225 million of 4.45% senior notes due July 2013 and used the net proceeds to repay approximately $204 million of our Medium-Term notes and approximately $21 million of short-term debt. In 2002, we made $93 million in scheduled Medium-Term note payments using a combination of cash from operations and proceeds from our commercial paper program.

Interest Rate Swaps

To maintain an effective capital structure, it is our policy to borrow funds using a mix of fixed-rate debt and variable-rate debt. We have entered into interest rate swap agreements for the purpose of hedging the interest rate risk associated with our fixed-rate and variable-rate debt obligations. At December 31, 2004, including the effects of $175 million of interest rate swaps, 72% of our total short-term and long-term debt was fixed.

Minority Interest

As a result of our consolidation of SouthStar's accounts effective January 1, 2004, we recorded Piedmont's portion of SouthStar's contributed capital as a minority interest on our consolidated balance sheet and included it as a component of our total capitalization. We also recorded a cash distribution of $14 million for SouthStar's dividend distribution to Piedmont in our consolidated statement of cash flows as a financing activity.

Common Stock

In November 2004, we completed our public offering of 11.04 million shares of common stock, generating net proceeds of approximately $332 million. We used the proceeds to purchase the outstanding capital stock of NUI and to repay short-term debt incurred to fund our purchase of Jefferson Island.

In February 2003, we completed our public offering of 6.4 million shares of common stock. The offering generated net proceeds of approximately $137 million, which we used to repay outstanding short-term debt and for general corporate purposes.

Dividends on Common Stock

In February 2005, we announced a 7% increase in our common stock dividend, raising the quarterly dividend from $0.29 per share to $0.31 per share, which indicates an annual dividend of $1.24 per share. The new quarterly dividend will be paid March 1, 2005, to shareholders of record as of the close of business February 18, 2005. In April 2004, we announced a 4% increase in our common stock dividend, raising the quarterly dividend from $0.28 per share to $0.29 per share, which indicated an annual dividend of $1.16 per share. In April 2003, our common stock dividend was increased by 4% from $0.27 per share to $0.28 per share, which indicated an annual dividend of $1.12 per share. For information on the restrictions of our ability to pay dividends on common stock, see Note 9.

Shelf Registration

In October 2004, we filed a new shelf registration statement with the SEC for authority to increase our aggregate capacity to $1.5 billion of various capital securities. The shelf registration statement was declared effective in November 2004. We currently have remaining capacity under that registration statement of approximately $957 million. We may seek additional financing through debt or equity offerings in the private or public markets at any time.

CRITICAL ACCOUNTING POLICIES

The preparation of our financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We based our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. We evaluate our estimates on an ongoing basis, and our actual results may differ from these estimates. Each of the following 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 ratesetting 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)

Atlanta Gas Light was ordered by the Georgia Commission to undertake a PRP, which will replace all bare steel and cast iron pipe in its system in the state of Georgia within a 10-year period beginning October 1, 1998. Atlanta Gas Light initially identified, and provided notice to the Georgia Commission in accordance with this order, 2,312 miles of bare steel and cast iron pipe to be replaced. Atlanta Gas Light has subsequently identified an additional 188 miles of pipe subject to replacement under this program. If Atlanta Gas Light does not perform in accordance with this order, it can be assessed certain nonperformance penalties. However, to date, Atlanta Gas Light is in full compliance. The order also provides for recovery of all prudent costs incurred in the performance of the program, which Atlanta Gas Light 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

The determination of future expected costs involves judgment. Factors that must be considered in estimating the future expected costs are projected capital expenditure spending and remaining footage of infrastructure to be replaced for the remaining years of the program. Atlanta Gas Light recorded a long-term liability of $242 million as of December 31, 2004 and $323 million as of December 31, 2003, which represented engineering estimates for remaining capital expenditure costs in the PRP. As of December 31, 2004, Atlanta Gas Light had recorded a current liability of $85 million, representing expected PRP expenditures for the next 12 months. We report these estimates on an undiscounted basis. If the recorded liability for PRP had been higher or lower by $10 million, Atlanta Gas Light's expected recovery would have changed by approximately $1 million.

The PRP is also an issue in the current Atlanta Gas Light rate proceeding. It is possible the Georgia Commission may alter the recovery method for the costs we incur or may disallow cost recovery while maintaining the requirement to replace the bare steel and cast iron pipe. Changes to the recovery of PRP costs could result in an impairment of our regulatory asset of $361 million at December 31, 2004, if costs are disallowed or if it is no longer probable that accrued costs would be recoverable from ratepayers in the future.

ENVIRONMENTAL REMEDIATION LIABILITIES

Atlanta Gas Light historically reported estimates of future remediation costs based on probabilistic models of potential costs. We report these estimates on an undiscounted basis. As we continue to conduct the actual remediation and enter cleanup contracts, Atlanta Gas Light is increasingly able to provide conventional engineering estimates of the likely costs of many elements of its remediation program. These estimates contain various engineering uncertainties, and Atlanta Gas Light continuously attempts to refine and update these engineering estimates. In addition, Atlanta Gas Light continues to review technologies available for cleanup of its two largest sites, Savannah and Augusta, Georgia, which, if proven, could have the effect of further reducing its total future expenditures.

Our latest available estimate as of September 30, 2004 for those elements of the remediation program with in-place contracts or engineering cost estimates is $36 million. This is a reduction of $30 million from the estimate as of September 30, 2003 of projected engineering and in-place contracts, resulting from $50 million of program expenditures during the 12 months ended September 30, 2004. During this same 12-month period, Atlanta Gas Light realized increases in its future cost estimates totaling $20 million related to an increase in the contract value at Augusta, Georgia for treatment of two areas and additional deep excavation of contaminants; the addition of harbor sediment removal at St. Augustine; an increase at Savannah for the phase 2 excavation and a partially offsetting decrease in engineering and oversight costs; and an increase in program management costs due to legal matters, environmental regulatory activities and oversight costs for the extension of work at Savannah and Augusta. For elements of the remediation program where Atlanta Gas Light still cannot perform engineering cost estimates, considerable variability remains in available estimates. The estimated remaining cost of future actions at these sites is $14 million.

Atlanta Gas Light estimates certain other costs paid directly by it related to administering the remediation program and remediation of sites currently in the investigation phase. Through January 2006, Atlanta Gas Light estimates the administration costs to be $2 million. Beyond January 2006, these costs are not estimable. For those sites currently in the investigation phase our estimate is $9 million, which is based on preliminary data received during 2004 with respect to the existence of contamination of those sites. Our range of estimates for these sites is from $4 million to $15 million. We have accrued the midpoint of our range, or $9 million, as this is our best estimate at this phase of the remediation process.

Atlanta Gas Light's environmental remediation liability is included in its corresponding regulatory asset. As of December 31, 2004, the regulatory asset was $166 million, which is a combination of the accrued remediation liability and unrecovered cash expenditures. Atlanta Gas Light'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 it may be held liable but with respect to which the amount cannot be reasonably forecast. Atlanta Gas Light's estimate also does not include any potential cost savings from the new cleanup technologies referenced above.

In New Jersey, Elizabethtown Gas is currently conducting remediation activities with oversight from the New Jersey Department of Environmental Protection. Although the actual total cost of future environmental investigation and remediation efforts cannot be estimated with precision, the range of reasonably probable costs is from $30 million to $116 million. As of December 31, 2004, no value within this range is better than any other value, so we recorded a liability of $30 million.

Elizabethtown Gas' prudently incurred remediation costs for the New Jersey properties have been authorized by the NJBPU to be recoverable in rates through its Remediation Adjustment Clause. As a result, Elizabethtown Gas has recorded a regulatory asset of approximately $34 million, inclusive of interest, as of December 31, 2004, reflecting the future recovery of both incurred costs and future remediation liabilities in the state of New Jersey. Elizabethtown Gas has also been successful in recovering a portion of remediation costs incurred in New Jersey from its insurance carriers and continues to pursue additional recovery. As of December 31, 2004, the variation between the amounts of the environmental remediation cost liability recorded on the consolidated balance sheet and the associated regulatory asset is due to expenditures for environmental investigation and remediation exceeding recoveries from ratepayers and insurance carriers.

We also own several former NUI remediation sites located outside of New Jersey. One site, in Elizabeth City, North Carolina, is subject to an order by the North Carolina Department of Energy and Natural Resources. We do not have precise estimates for the cost of investigating and remediating this site, although preliminary estimates for these costs range from $4 million to $16 million. As of December 31, 2004, we have recorded a liability of $4 million related to this site. There is another site in North Carolina where investigation and remediation is probable, although no regulatory order exists and we do not believe costs associated with this site can be reasonably estimated. In addition, there are as many as six other sites with which NUI had some association, although no basis for liability has been asserted. We do not believe that costs to investigate and remediate these sites, if any, can be reasonably estimated at this time.

With respect to these costs, we currently pursue or intend to pursue recovery from ratepayers, former owners and operators and insurance carriers. Although we have been successful in recovering a portion of these remediation costs from our insurance carriers, we are not able to express a belief as to the success of additional recovery efforts. We are working with the regulatory agencies to prudently manage our remediation costs so as to mitigate the impact of such costs on both ratepayers and shareholders.

REVENUE RECOGNITION

Rate structures for Elizabethtown Gas, Virginia Natural Gas, Florida Gas and Chattanooga Gas include volumetric rate designs that allow recovery of costs through gas usage. These utilities recognize revenues from sales of natural gas and transportation services in the same period in which they deliver the related volumes to customers. These utilities also bill and recognize sales revenues from residential and certain commercial and industrial customers on the basis of scheduled meter readings. In addition, they 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. Furthermore, included in the rates charged by Elizabethtown Gas, Virginia Natural Gas and Chattanooga Gas is a WNA factor, which offsets the impact of unusually cold or warm weather on operating margins.

PURCHASE PRICE ALLOCATION

During 2004, we completed two significant acquisitions, Jefferson Island and NUI. We purchased Jefferson Island for an adjusted price of $90 million, which included approximately $9 million of working gas inventory. We purchased NUI for $225 million in cash plus the assumption of NUI's outstanding net debt. At closing, NUI had $709 million in debt and approximately $109 million of cash on its balance sheet, bringing the net value of the transaction to approximately $825 million.

In accordance with SFAS No. 141, "Business Combinations" (SFAS 141), the purchase price of Jefferson Island and NUI should be allocated to the various assets and liabilities acquired at their estimated fair value. Estimating fair values can be complex and can require significant applications of judgment. It most commonly affects nonregulated property, plant and equipment, nonregulated assets and liabilities, and intangible assets, including those with indefinite lives. Our evaluation of NUI's identifiable assets acquired and liabilities assumed is a preliminary valuation based on currently available information and is subject to final adjustments. The valuations are considered preliminary since they are based on limited information available to management and independent appraisers. Generally, we have, if necessary, up to one year from the acquisition date to finalize the purchase price allocation. Any changes in estimates used in the allocation of the purchase price that are made after the one-year look-back period would be recognized in earnings during the period in which the change in estimate is made.

We expect to record goodwill associated with the acquisitions of Jefferson Island and NUI that will be required to be tested for impairment at least annually in accordance with the requirements of SFAS 142. The goodwill associated with the acquisition of NUI is expected to be allocated to our distribution operations segment. Based on our annual assessment at December 31, 2004, no impairment of goodwill is indicated, and our calculation indicates that the estimated fair value of this segment exceeds the carrying value, including goodwill, by a significant amount. For more information on our methodology used to test goodwill for impairment, see Note 1.

DERIVATIVES AND HEDGING ACTIVITIES

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

SFAS 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. If the derivatives meet those criteria, SFAS 133 allows a derivative's gains and losses to offset related results on the hedged item in the income statement in the case of a fair value hedge, or to record the gains and losses in other comprehensive income until maturity in the case of a cash flow hedge. Additionally, SFAS 133 requires that a company formally designate a derivative as a hedge as well as document and assess the effectiveness of derivatives associated with transactions that receive hedge accounting treatment. Two areas where SFAS 133 applies are interest rate swaps and gas commodity contracts at both Sequent and SouthStar. Our derivative and hedging activities are described in further detail in Note 4.

Interest Rate Swaps

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

Commodity-related Derivative Instruments

We are exposed to risks associated with changes in the market price of natural gas. Elizabethtown Gas utilizes certain derivatives for non-trading purposes to hedge the impact of market fluctuations on assets, liabilities and other contractual commitments. Pursuant to SFAS 133, such derivative products are marked-to-market each reporting period. Pursuant to regulatory requirements, realized gains and losses related to such derivatives are reflected in purchased gas costs and included in billings to customers. Unrealized gains and losses are reflected as a regulatory asset (loss) or liability (gain), as appropriate, on the consolidated balance sheet. Through Sequent and SouthStar, we use derivative instruments to reduce our exposure to the risk of changes in the prices of natural gas. Sequent recognizes the change in value of derivative instruments as an unrealized gain or loss in revenues in the period when the market value of the portfolio changes. This is primarily due to newly originated transactions and the effect of price changes. Sequent recognizes cash inflows and outflows associated with the settlement of these risk management activities in operating cash flows and reports these settlements as receivables and payables separately from risk management activities in the balance sheet as energy marketing receivables and trade payables.

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

The purchase, storage and sale of natural gas are accounted for differently from 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 of our purchased gas inventory. Costs to store the gas are recognized in the period the costs are incurred. We recognize revenues and cost of gas sold in our statement of consolidated income in the period we sell gas and it is delivered out of the storage facility.

The derivatives we use to mitigate commodity price risk and substantially lock in the margin upon the sale of stored gas are accounted for at fair value and marked to market each period, with changes in fair value recognized as unrealized gains or losses in the period of change. This difference in accounting, the accrual basis for our gas storage inventory versus mark-to-market accounting for the derivatives used to mitigate commodity price risk, can result in volatility in our reported net income. Based on Sequent's storage positions at December 31, 2004, a $0.10 forward NYMEX change would result in a $0.3 million impact to Sequent's EBIT.

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

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

SouthStar also uses derivative instruments to manage exposures arising from changing commodity prices. SouthStar's objective for holding these derivatives is to minimize this risk using the most effective methods to reduce or eliminate the impacts of these exposures. A significant portion of SouthStar's derivative transactions are designated as cash flow hedges under SFAS 133. Derivative gains or losses arising from cash flow hedges are recorded in other comprehensive income (OCI) and are reclassified into earnings in the same period as the settlement of the underlying hedged item. Any hedge ineffectiveness, defined as when the gains or losses on the hedging instrument do not perfectly offset the losses or gains on the hedged item, is recorded into earnings in the period in which it occurs.

SouthStar currently has minimal hedge ineffectiveness. SouthStar's remaining derivative instruments do not meet the hedge criteria under SFAS 133. Therefore, changes in their fair value are recorded in earnings in the period of change.

Weather Derivative Contracts

SouthStar enters into weather derivative contracts, from time to time, 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." There were no weather derivative contracts outstanding as of December 31, 2004 and 2003.

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 on actual outcomes or changes in the facts or expectations surrounding each potential exposure.

ALLOWANCE FOR DOUBTFUL ACCOUNTS

For the majority of our receivables, we establish an allowance for doubtful accounts based on our collections experience. Some of the more important factors that we use in the preparation of our allowance amounts are the customer status, the customer's aging balance, and historical collection experience and trends. On certain other receivables where we are aware of a specific customer's inability or reluctance to pay, we record an allowance for doubtful accounts against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be different. Circumstances that could affect our estimates include, but are not limited to, customer credit issues, the level of natural gas prices and general economic conditions.

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.

At December 31, 2004, we increased our minimum pension liability by approximately $18 million, resulting in an aftertax loss to OCI of $11 million. At December 31, 2003, we reduced our minimum pension liability by approximately $14 million, which resulted in an aftertax gain to OCI of $8 million. These adjustments reflect our 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 decrease the AGL Resources Inc. Retirement Plan's ABO by approximately $37 million and would decrease annual pension expense by approximately $4 million. A one-percentage-point decrease in the assumed discount rate would increase the AGL Resources Inc. Retirement Plan's ABO by approximately $46 million and would increase annual pension expense by approximately $4 million. Additionally, a one-percentage-point increase or decrease in the expected return on assets would decrease or increase the AGL Resources Inc. Retirement Plan's pension expense by approximately $3 million.

Additionally, we have recorded a $36 million liability for the amount of NUI's projected benefit obligation in excess of the fair value of pension plan assets at the date of our acquisition of NUI. The acquisition will impact our pension plan expenses and liabilities. A one-percentage-point increase in the discount rate would decrease the NUI Corporation Retirement Plan's ABO by approximately $12 million and would decrease the annual benefit cost by approximately $0.1 million. A one-percentage-point decrease in the discount rate would increase the NUI Corporation Retirement Plan's ABO by approximately $13 million, and increase our annual expense by approximately $0.1 million. In addition, a one-percentage-point increase or decrease in the NUI Corporation Retirement Plan's expected return on assets would decrease or increase our pension expenses by approximately $0.1 million.

As of December 31, 2004, the market value of the pension assets was $390 million compared to a market value of $259 million as of December 31, 2003. The net increase of $131 million resulted from

- contributions of $13 million in April 2004
- contributions of $1 million in 2004 to our supplemental retirement plan
- an actual return on plan assets of $26 million less benefits paid of $19 million
- the acquisition of NUI assets of $111 million

Our $13 million in contributions to the pension plan in 2004 reduced annual pension expense by approximately $1 million in 2004. 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, 2004, and our pension expense for 2005. 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, 2004. Our actual returns may also be positively or negatively impacted as a result of future performance in the equity and bond markets.

ACCOUNTING DEVELOPMENTS

For information regarding accounting developments, see Note 3.

RISK FACTORS

The following are some of the factors that could affect our future performance or could cause actual results to differ materially from those expressed or implied in our forward-looking statements. We cannot predict every event and circumstance that may adversely affect our business, and therefore the risks and uncertainties described below may not be 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 cause serious damage to our business in the future.

RISKS RELATED TO THE NUI ACQUISITION

We may encounter difficulties integrating NUI into our business and may not fully attain or retain, or achieve within a reasonable time frame, expected strategic objectives, cost savings and other benefits of the acquisition.

We expect to realize strategic and other benefits as a result of our acquisition of NUI. Our ability to realize these benefits or successfully integrate NUI's businesses, however, is subject to certain risks and uncertainties, including:

- The costs of integrating NUI and upgrading and enhancing its operations may be higher than we expect and may require more resources, capital expenditures and management attention than anticipated.
- Employees important to NUI's operations may decide not to continue employment with us.
- We may be required to allocate some of the cost savings achieved through the integration of NUI to our existing regulated utilities, which could prevent us from retaining some of the benefits achieved if the allocated cost savings result in rate reductions in future rate proceedings.
- We may be unable to maintain and enhance our relationship with NUI's existing customers and regulators.
- We may be unable to anticipate or manage risks that are unique to NUI's business, including those related to its workforce, customer demographics, regulatory environment, information systems and diverse geography.
- We may be unable to appropriately and in a timely manner adapt to both existing and changing economic, regulatory and competitive conditions.

- The financial results of operations we acquired are subject to many of the same factors that have historically affected our financial condition and results of operations, including weather sensitivity; extensive federal, state and local regulation; increasing gas costs; competition and market risks; and national, regional and local economic conditions.

Our failure to manage these risks, or other risks related to the acquisition that are not presently known to us, could prevent us from realizing the expected benefits of the acquisition and also may have a material adverse effect on our results of operations and financial condition following the transaction.

NUI has certain liabilities and obligations related to its pre-acquisition activities that may result in unanticipated costs and expenses to us.
NUI has been, and continues to be, the subject of various lawsuits, regulatory audits, investigations and settlements related to certain of its and its affiliates' business practices prior to the date of the acquisition agreement. We will bear the costs of any liability, expense or obligation related to ongoing or new lawsuits, regulatory audits, investigations or claims related to these pre-acquisition activities. Additionally, management of these claims and liabilities may require a disproportionate amount of our management's time and attention. A failure to manage these risks could negatively affect our results of operations, our financial condition and our reputation in the industry, and may reduce the anticipated benefits of the acquisition.

NUI has material weaknesses in its internal controls that may force us to incur unanticipated costs to resolve after closing.
NUI's external and internal auditors performed audits during its fiscal 2003 and 2004 years that identified material weaknesses in NUI's internal controls. Additional internal control issues and deficiencies were identified in the focused audit of NUI and its affiliates that was conducted at the request of the NJBPU. We have initiated our efforts to assess the systems of internal control related to NUI's business in order to comply with the requirements of SOX 404. At this time, however, we believe these operations continue to have material deficiencies in their internal controls that we will be required to address and resolve. We cannot make any assurance that our systems of internal and disclosure controls and procedures will be able to detect or prevent all errors or fraud or ensure that all material information regarding weaknesses in controls will be made known to management in the near term. We may incur significant additional costs to resolve these internal control and disclosure issues.

RISKS RELATED TO OUR BUSINESS

Risks related to the regulation of our businesses could affect 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 Georgia Commission, the Tennessee Authority, the NJPBU, the Florida Commission, the Virginia Commission and the Maryland Commission. These authorities regulate many aspects of our distribution operations, including construction and maintenance of facilities, operations, safety, rates that we can charge customers, rates of return, the authorized cost of capital, recovery of pipeline replacement and environmental remediation costs, carrying costs we charge Marketers for gas held in storage for their customer accounts and relationships with our affiliates. Our ability to obtain rate increases and rate supplements to maintain our current rates of return depends on 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 business to alternative unregulated suppliers of gas sales services.

In 1997, the Georgia legislature enacted the Natural Gas Competition and Deregulation Act. To date, Georgia is the only state in the nation that has fully deregulated gas distribution operations, which ultimately resulted in Atlanta Gas Light 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 Atlanta Gas Light 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 Atlanta Gas Light to provide retail gas sales service once again or require SouthStar to change the nature of how it provides natural gas to certain customers. In addition, the Georgia Commission has statutory authority on an emergency basis to order Atlanta Gas Light to temporarily provide the same retail gas service that it provided prior to deregulation. If any of these events were to occur, we would incur costs to reverse the restructuring process or potentially lose the earnings opportunity embedded within the current marketing framework. Furthermore, the Georgia Commission has authority to change the terms under which we charge Marketers for certain supply-related services, which could also affect our future earnings.

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), Atlanta Gas Light had approximately 1.4 million end-use customers in Georgia. In contrast, at December 31, 2004, Atlanta Gas Light had only 10 certificated and active Marketers in Georgia, four of which (based on customer count and including SouthStar) accounted for approximately 46% of our total operating margin for 2004. As a result, Atlanta Gas Light now depends on a concentrated number of customers for revenues. The failure of these Marketers to pay Atlanta Gas Light could adversely affect Atlanta Gas Light's business and results of operations and expose it to difficulties in collecting Atlanta Gas Light's accounts receivable. 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 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 "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 had 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 statement of income 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, oil and propane providers 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. 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. In the case of industrial and agricultural customers, adverse economic conditions, including higher gas costs, could also cause these customers to bypass our systems in favor of special competitive contracts with lower per unit costs.

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. The consolidation of this industry and the pricing to gain market share may affect our margins. We expect this trend to continue in the near term, and the increasing competition for asset management deals could result in downward pressure on the volume of transactions and the related margins available in this portion of Sequent's business.

Our asset management arrangements between Sequent and the affiliated local distribution companies 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 our affiliates Atlanta Gas Light, Virginia Natural Gas and Chattanooga Gas and shares profits it earns from the management of those assets with those customers and their customers. In addition, Sequent has asset management agreements with certain nonaffiliated customers.

On April 1, 2005, Sequent plans to commence asset management responsibilities for Elizabethtown Gas, Florida Gas and Elkton Gas. The contract terms are currently being negotiated. Sequent's results could be significantly impacted if these agreements are not renewed or are amended or renewed with less favorable terms.

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 57% 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 at Sequent 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, 2004 had a 1-day holding period VaR of $0.1 million and a 10-day holding period VaR of $0.2 million.

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 Sequent 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. Failure to comply with these laws and regulations and failure to obtain any required permits and licenses may expose us to fines, penalties and/or interruptions in our operations that could be material to our results of operations.

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, particularly if those costs are not fully recoverable from our customers. 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, cleanup has been completed at these sites, and as of December 31, 2004, the remediation program was approximately 78% complete. As of December 31, 2004, projected costs associated with the MGP sites were $56 million. For elements of the MGP program where we still cannot perform engineering cost estimates, considerable variability remains in available future cost estimates.

In addition, NUI is associated with as many as 6 former sites in New Jersey and 10 former sites in other states. Material cleanups of these sites have not been completed nor are precise estimates available for future cleanup costs. For the New Jersey sites, cleanup cost estimates range from $30 million to $116 million. Costs have been estimated for only 1 of the 10 non–New Jersey sites, for which current estimates range from $4 million to $16 million.

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

The current strategy of our telecommunications business is based on 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 may evaluate and acquire assets or businesses or enter into joint venture arrangements that we believe complement our existing businesses and related assets. As a result, the relative makeup of our business is subject to change. 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. Realization of the anticipated benefits of acquisitions or other transactions could take longer than 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

Our ability to successfully make strategic acquisitions and investments will depend on

- the extent to which acquisitions and investment opportunities become available
- our success in bidding for the opportunities that do become available
- regulatory approval, if required, of the acquisitions on favorable terms
- our access to capital and the terms upon which we obtain capital
- if we are unable to make strategic investments and acquisitions, we may be unable to grow

Our growth may be restricted by the capital-intensive nature of our business.

In order to maintain our historic growth, we must construct additions to our natural gas distribution system each year. The cost of this construction may be affected by the cost of obtaining government approvals, development project delays or changes in project costs. Weather, general economic conditions and the cost of funds to finance our capital projects can materially alter the cost of a project. Our cash flows are not fully adequate to finance the cost of this construction. As a result, we must fund a portion of our cash needs through borrowings and the issuance of common stock. Our ability to finance the cost of constructing additions to our system depends on our ability to borrow funds or sell our common stock.

Changes in weather conditions may affect our earnings.
Weather conditions and other natural phenomena can have a large impact on our earnings. Severe weather conditions can impact our suppliers and the pipelines that deliver gas to our distribution system. Extended mild weather, either during the winter period or summer period, can have a significant impact on demand for and the cost of natural gas.

We have a WNA mechanism for Elizabethtown Gas, Chattanooga Gas and Virginia Natural Gas that partially offsets the impact that unusually cold or warm weather has on residential and commercial customer billings and margin. The WNA is most effective in a reasonable temperature range relative to normal weather using historical averages. The protection afforded by the WNA depends on continued regulatory approval. The loss of this continued regulatory approval could make us more susceptible to weather-related earnings fluctuations.

Inflation and increased gas costs could adversely impact our customer base and customer collections and increase our level of indebtedness.
Inflation has caused increases in certain operating expenses and has required us to replace assets at higher costs. We have a process in place to continually review the adequacy of our utility gas rates in relation to the increasing cost of providing service and the inherent regulatory lag in adjusting those gas rates. Historically, we have been able to budget and control operating expenses and investments within the amounts authorized to be collected in rates and intend to continue to do so. The ability to control expenses is an important factor that will influence future results.

Rapid increases in the price of purchased gas, which occurred in some prior years, cause us to experience a significant increase in short-term debt because we must pay suppliers for gas when it is purchased, which can be significantly in advance of when these costs may be recovered through the collection of monthly customer bills for gas delivered. Increases in purchased gas costs also slow our utility collection efforts as customers are more likely to delay the payment of their gas bills, leading to higher-than-normal accounts receivable. This situation also results in higher short-term debt levels and increased bad debt expense. Should the price of purchased gas increase significantly in the upcoming heating season, we would expect increases in our short-term debt, accounts receivable and bad debt expense during 2005.

Finally, higher costs of natural gas in recent years have already caused many of our utility customers to conserve in the use of our gas services and could lead to even more customers utilizing such conservation methods.

A decrease in the availability of adequate pipeline transportation capacity could reduce our revenues and profits.
Our gas supply depends on the availability of adequate pipeline transportation and storage capacity. We purchase a substantial portion of our gas supply from interstate sources. Interstate pipeline companies transport the gas to our system. A decrease in interstate pipeline capacity available to us or an increase in competition for interstate pipeline transportation and storage service could reduce our normal interstate supply of gas.

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 them 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.

As a result of cross-default provisions in our borrowing arrangements, we may be unable to satisfy all of our outstanding obligations in the event of a default on our part.
Our Credit Facility and the indenture under which Atlanta Gas Light's outstanding Medium-Term notes were issued contain cross-default provisions. Accordingly, should an event of default occur under some of our debt agreements, we face the prospect of being in default under other of our debt agreements, obliged in such instance to satisfy a large portion of our outstanding indebtedness and unable to satisfy all of our outstanding obligations simultaneously.

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.

S&P, Moody's and 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 need to take steps or change our business plans in ways that may affect our growth and earnings per share. S&P, Moody's and Fitch currently assign our senior unsecured debt a rating of BBB+, Baa1 and A, respectively. Our commercial paper currently is rated A-2, P-2 and F-2 by S&P, Moody's and Fitch, respectively. If the rating agencies downgrade 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, 2004, if our credit rating had fallen below investment grade, we would have been required to provide collateral of approximately $20 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 "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. In addition, higher interest rates, all other things equal, reduce the earnings that we derive from transactions where we capture the difference between authorized returns and short-term borrowings.

Our tax rate may be increased and/or tax laws affecting us can change that may have an adverse impact on our cash flows and profitability.
The rates of federal, state and local taxes applicable to the industries in which we operate, which often fluctuate, could be increased by the respective taxing authorities. In addition, the tax laws, rules and regulations that affect our business could change. Any such increase or change could adversely impact our cash flows and profitability.

RISKS RELATED TO OUR INDUSTRY

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, accidents 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, which in turn could lead to 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.

Natural disasters, terrorist activities and the potential for military and other actions could adversely affect our businesses.
Natural disasters may damage our assets. 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, including particularly those in the energy industry, 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.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to risks associated with commodity prices, interest rates and credit. Commodity price risk is defined as the potential loss that we may incur as a result of changes in the fair value of a particular instrument or commodity. Interest rate risk results from our portfolio of debt and equity instruments that we issue to provide financing and liquidity for our business. Credit risk results from the extension of credit throughout all aspects of our business, but is particularly concentrated at Atlanta Gas Light in distribution operations and in wholesale services.

Our Risk Management Committee (RMC) is responsible for the overall establishment of risk management policies and the monitoring of compliance with, and adherence to the terms within these policies, including approval and authorization levels and delegation of these levels. Our RMC consists of senior executives who monitor commodity price risk positions, corporate exposures, credit exposures and overall results of our risk management activities, and is chaired by our chief risk officer, who is responsible for ensuring that appropriate reporting mechanisms exist for the RMC to perform its monitoring functions. Our risk management activities and related accounting treatments are described in further detail in Note 4.

COMMODITY PRICE RISK

Wholesale Services

This segment routinely utilizes various types of financial and other instruments to mitigate certain commodity price risks inherent in the natural gas industry. These instruments include a variety of exchange-traded and over-the-counter energy contracts, such as forward contracts, futures contracts, option contracts and financial swap agreements. The following table includes the fair values and average values of our energy marketing and risk management assets and liabilities as of December 31, 2004 and 2003. We base the average values on monthly averages for the years ended December 31, 2004 and 2003.

	Average 12-month Values		Value at:	
In millions	**2004**	2003	**Dec 31, 2004**	Dec 31, 2003
Asset				
Natural gas contracts	**$28**	$14	**$36**	$13

	Average 12-month Values		Value at:	
In millions	**2004**	2003	**Dec 31, 2004**	Dec 31, 2003
Liability				
Natural gas contracts	**$21**	$14	**$19**	$18

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. We use a 1-day and a 10-day holding period and a 95% confidence interval to evaluate our VaR exposure. A 95% confidence interval means there is a 5% probability that the actual change in portfolio value will be greater than the calculated VaR value over the holding period. We calculate VaR based on the variance-covariance technique. This technique requires several assumptions for the basis of the calculation, such as price volatility, confidence interval and holding period. Our VaR may not be comparable to a similarly titled measure of another company because, although VaR is a common metric in the energy industry, there is no established industry standard for calculating VaR or for the assumptions underlying such calculations.

Our open exposure is managed in accordance with established policies that limit market risk and require daily reporting of potential financial exposure to senior management, including the chief risk officer. Because we generally manage physical gas assets and economically protect our positions by hedging in the futures markets, our open exposure is generally minimal, permitting us to operate within relatively low VaR limits. We employ daily risk testing, using both VaR and stress testing, to evaluate the risks of our open positions.

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

In millions	1-day	10-day
2004		
Period end	**$0.1**	**$0.2**
12-month average	**0.1**	**0.3**
High	**0.4**	**1.3**
Low[1]	**0.0**	**0.0**
2003		
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.

Energy Investments

SouthStar's use of derivatives is governed by a risk management policy created and monitored by its risk management committee which prohibits the use of derivatives for speculative purposes. This policy also establishes VaR limits of $0.5 million on a 1-day holding period and $0.7 million on a 10-day holding period. A 95% confidence interval is used to evaluate VaR exposure. The maximum VaR experienced during 2004 was less than $0.2 million for the 1-day holding period and $0.5 million for the 10-day holding period.

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 million of the $300 million Senior Notes due 2011, and $75 million of the $150 million principal amount of notes payable to Trusts due in 2041. In March 2004, we adjusted our fixed- to variable-rate debt obligations and terminated an interest rate swap on $100 million of the $225 million principal amount of Senior Notes due 2013. More information about our interest rate swaps are shown in the following table:

Dollars in millions		Market Value of Interest Rate Swap Derivatives		Market Value as of:	
Notional Amount	Fixed-rate	Effective Variable Rate[1]	Maturity	Dec 31, 2004	Dec 31, 2003
$75	8.0%	3.6%	May 15, 2041	$ 3	$ 3
$100	7.1	5.2	January 14, 2011	(2)	(2)
$100	4.5	—	April 15, 2013[2]	—	(5)

[1] As of December 31, 2004.

[2] Terminated in March 2004.

CREDIT RISK

Distribution Operations

Atlanta Gas Light has a concentration of credit risk because it bills only 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 Atlanta Gas Light's tariff allow Atlanta Gas Light to obtain security support in an amount equal to a minimum of two times a Marketer's highest month's estimated bill from Atlanta Gas Light. For 2004, the four largest Marketers based on customer count, one of which was SouthStar, accounted for approximately 46% of our operating margin and 61% of distribution operations' operating margin.

Several factors are designed to mitigate our risks from the increased concentration of credit that has resulted from deregulation. In addition to the security support described above, Atlanta Gas Light 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 Atlanta Gas Light's credit risk exposure to Marketers.

Atlanta Gas Light also faces potential credit risk in connection with assignments to Marketers of interstate pipeline transportation and storage capacity. Although Atlanta Gas Light 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 Atlanta Gas Light. 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, 2004, Sequent's top 20 counterparties represented approximately 57% of the total counterparty exposure of $328 million, derived by adding the top 20 counterparties' exposures divided by the total of Sequent's counterparties' exposures.

As of December 31, 2004, Sequent's counterparties, or the counterparties' guarantors, had a weighted average S&P equivalent credit rating of A- compared to BBB at December 31, 2003. The S&P equivalent credit rating is determined by a process of converting the lower of the S&P or Moody's ratings to an internal rating ranging from 9 to 1, with 9 being equivalent to AAA/Aaa by S&P and Moody's and 1 being D or Default by S&P and Moody's. A counterparty that does not have an external rating is assigned an internal rating based on the strength of the financial ratios of that counterparty.

To arrive at the weighted average credit rating, each counterparty's assigned internal rating is multiplied by the counterparty's credit exposure and summed for all counterparties. That sum is divided by the aggregate total counterparties' exposures, and this numeric value is then converted to an S&P equivalent. The following tables show Sequent's commodity receivable and payable positions as of December 31, 2004 and 2003:

Gross receivables

In millions	As of Dec 31, 2004	As of Dec 31, 2003	Change
Receivables with netting agreements in place:			
Counterparty is investment grade	**$378**	$282	$ 96
Counterparty is non–investment grade	**36**	13	23
Counterparty has no external rating	**78**	9	69
Receivables without netting agreements in place:			
Counterparty is investment grade	**16**	15	1
Counterparty is non–investment grade	**6**	—	6
Counterparty has no external rating	**—**	—	—
Amount recorded on balance sheet	**$514**	$319	$195

Gross payables

In millions	As of Dec 31, 2004	As of Dec 31, 2003	Change
Payables with netting agreements in place:			
Counterparty is investment grade	**$291**	$206	$ 85
Counterparty is non–investment grade	**45**	31	14
Counterparty has no external rating	**139**	45	94
Payables without netting agreements in place:			
Counterparty is investment grade	**40**	29	11
Counterparty is non–investment grade	**6**	3	3
Counterparty has no external rating	**—**	15	(15)
Amount recorded on balance sheet	**$521**	$329	$192

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.

STATEMENTS OF CONSOLIDATED INCOME

In millions, except per share amounts	Years ended December 31, 2004	2003	2002
Operating revenues	**$1,832**	$ 983	$ 877
Operating expenses			
Cost of gas	**994**	339	268
Operation and maintenance	**377**	283	274
Depreciation and amortization	**99**	91	89
Taxes other than income taxes	**30**	28	29
Total operating expenses	**1,500**	741	660
Gain on sale of Caroline Street campus	**—**	16	—
Operating income	**332**	258	217
Equity in earnings of SouthStar	**—**	46	27
Other (loss) income	**—**	(6)	3
Minority interest	**(18)**	—	—
Interest expense	**(71)**	(75)	(86)
Earnings before income taxes	**243**	223	161
Income taxes	**90**	87	58
Income before cumulative effect of change in accounting principle	**153**	136	103
Cumulative effect of change in accounting principle, net of $5 in taxes	**—**	(8)	—
Net income	**$ 153**	$ 128	$ 103
Basic earnings per common share:			
Income before cumulative effect of change in accounting principle	**$ 2.30**	$ 2.15	$1.84
Cumulative effect of change in accounting principle	**—**	(0.12)	—
Basic earnings per common share	**$ 2.30**	$ 2.03	$1.84
Fully diluted earnings per common share:			
Income before cumulative effect of change in accounting principle	**$ 2.28**	$ 2.13	$1.82
Cumulative effect of change in accounting principle	**—**	(0.12)	—
Fully diluted earnings per common share	**$ 2.28**	$ 2.01	$1.82
Weighted average number of common shares outstanding:			
Basic	**66.3**	63.1	56.1
Fully diluted	**67.0**	63.7	56.6

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS — ASSETS

In millions	As of Dec 31, 2004	As of Dec 31, 2003
Current assets		
Cash and cash equivalents	**$ 49**	$ 17
Receivables		
Energy marketing	**514**	319
Gas	**217**	65
Other	**21**	12
Less allowance for uncollectible accounts	**(15)**	(2)
Total receivables	**737**	394
Income tax receivable	**29**	—
Unbilled revenues	**152**	40
Inventories		
Natural gas stored underground	**320**	198
Other	**12**	12
Total inventories	**332**	210
Energy marketing and risk management assets	**38**	13
Unrecovered environmental remediation costs — current portion	**27**	24
Unrecovered pipeline replacement program costs — current portion	**24**	22
Unrecovered seasonal rates	**11**	11
Other current assets	**58**	11
Total current assets	**1,457**	742
Property, plant and equipment		
Property, plant and equipment	**4,615**	3,390
Less accumulated depreciation	**1,437**	1,045
Property, plant and equipment — net	**3,178**	2,345
Deferred debits and other assets		
Goodwill	**354**	184
Unrecovered pipeline replacement program costs	**337**	410
Unrecovered environmental remediation costs	**173**	155
Investments in equity interests	**14**	101
Unrecovered postretirement benefit costs	**14**	9
Other	**113**	26
Total deferred debits and other assets	**1,005**	885
Total assets	**$5,640**	$3,972

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS — LIABILITIES AND CAPITALIZATION

In millions, except share amounts	As of Dec 31, 2004	As of Dec 31, 2003
Current liabilities		
Energy marketing trade payable	**$ 521**	$ 329
Short-term debt	**334**	306
Accounts payable — trade	**207**	74
Accrued pipeline replacement program costs — current portion	**85**	82
Customer deposits	**50**	19
Deferred purchased gas adjustment	**37**	30
Accrued interest	**28**	21
Accrued environmental remediation costs — current portion	**27**	40
Accrued wages and salaries	**23**	18
Energy marketing and risk management liabilities — current portion	**15**	17
Accrued taxes	**14**	15
Current portion of long-term debt	**—**	77
Other current liabilities	**136**	20
Total current liabilities	**1,477**	1,048
Accumulated deferred income taxes	**437**	376
Long-term liabilities		
Accrued pipeline replacement program costs	**242**	323
Accrued postretirement benefit costs	**58**	51
Accumulated removal costs	**94**	102
Accrued environmental remediation costs	**63**	43
Accrued pension obligations	**84**	39
Accrued pipeline demand charges	**38**	—
Other long-term liabilities	**30**	11
Total long-term liabilities	**609**	569
Deferred credits		
Unamortized investment tax credit	**20**	19
Regulatory tax liability	**12**	12
Other deferred credits	**41**	47
Total deferred credits	**73**	78
Commitments and contingencies (see Note 10)		
Minority interest	**36**	—
Capitalization		
Long-term debt	**1,623**	956
Common shareholders' equity, $5 par value; 750,000,000 shares authorized (see accompanying statements of consolidated common shareholders' equity)	**1,385**	945
Total capitalization	**3,008**	1,901
Total liabilities and capitalization	**$5,640**	$3,972

See Notes to Consolidated Financial Statements.

STATEMENTS OF CONSOLIDATED COMMON SHAREHOLDERS' EQUITY

In millions, except per share amounts	Common Stock Shares	Common Stock Amount	Premium on Common Stock	Earnings Reinvested	Other Comprehensive Income	Shares Held in Treasury and Trust	Total
Balance as of December 31, 2001	57.8	$289	$204	$237	$ (1)	$(39)	$ 690
Comprehensive income:							
Net income	—	—	—	103	—	—	103
Other comprehensive income (OCI) — loss resulting from unfunded pension obligation (net of tax benefit of $31)	—	—	—	—	(48)	—	(48)
Total comprehensive income							55
Dividends on common stock ($1.08 per share)	—	—	—	(61)	—	—	(61)
Benefit, stock compensation, dividend reinvestment and stock purchase plans (net of tax benefit of $1)	—	—	6	—	—	20	26
Balance as of December 31, 2002	57.8	289	210	279	(49)	(19)	710
Comprehensive income:							
Net income	—	—	—	128	—	—	128
OCI — gain resulting from unfunded pension obligation (net of tax of $6)	—	—	—	—	8	—	8
Unrealized gain from equity investments hedging activities (net of tax)	—	—	—	—	1	—	1
Total comprehensive income							137
Dividends on common stock ($1.11 per share)	—	—	—	(70)	—	—	(70)
Issuance of common shares:							
Equity offering on February 14, 2003	6.7	32	105	—	—	—	137
Benefit, stock compensation, dividend reinvestment and stock purchase plans (net of tax benefit of $2)	—	1	11	—	—	19	31
Balance as of December 31, 2003	64.5	322	326	337	(40)	—	945
Comprehensive income:							
Net income	—	—	—	**153**	—	—	**153**
OCI — loss resulting from unfunded pension obligation (net of tax benefit of $7)	—	—	—	—	**(11)**	—	**(11)**
Unrealized gain from hedging activities (net of tax of $2)	—	—	—	—	**4**	—	**4**
Other	—	—	—	—	**1**	—	**1**
Total comprehensive income							**147**
Dividends on common stock ($1.15 per share)	—	—	—	**(75)**	—	—	**(75)**
Issuance of common shares:							
Equity offering on November 24, 2004	**11.0**	**55**	**277**	—	—	—	**332**
Benefit, stock compensation, dividend reinvestment and stock purchase plans (net of tax benefit of $5)	**1.2**	**7**	**29**	—	—	—	**36**
Balance as of December 31, 2004	**76.7**	**$384**	**$632**	**$415**	**$(46)**	**$ —**	**$1,385**

See Notes to Consolidated Financial Statements.

STATEMENTS OF CONSOLIDATED CASH FLOWS

In millions	2004	Years ended December 31, 2003	2002
Cash flows from operating activities			
Net income	**$ 153**	$ 128	$ 103
Adjustments to reconcile net income to net cash flow provided by operating activities			
Depreciation and amortization	**99**	91	89
Deferred income taxes	**81**	55	82
Cumulative effect of change in accounting principle	**—**	13	—
Cash received from equity interests	**—**	40	—
Equity in earnings of unconsolidated subsidiaries	**(2)**	(47)	(27)
Gain on sale of Caroline Street campus	**—**	(16)	—
Change in risk management assets and liabilities	**(27)**	(1)	(3)
Changes in certain assets and liabilities			
Payables	**247**	61	244
Environmental remediation costs — net	**(13)**	(6)	(18)
Inventories	**(28)**	(91)	42
Receivables	**(264)**	(67)	(269)
Other — net	**41**	(38)	43
Net cash flow provided by operating activities	**287**	122	286
Cash flows from investing activities			
Acquisition of NUI, net of cash acquired	**(116)**	—	—
Property, plant and equipment expenditures	**(264)**	(158)	(187)
Acquisition of Jefferson Island	**(90)**	—	—
Purchase of Dynegy's 20% ownership interest in SouthStar	**—**	(20)	—
Cash received from sale of Caroline Street campus	**—**	23	—
Sale of US Propane	**31**	—	—
Cash received from equity interests	**—**	2	27
Other	**17**	8	(1)
Net cash flow used in investing activities	**(422)**	(145)	(161)
Cash flows from financing activities			
Issuances of senior notes	**450**	225	—
Equity offering	**332**	137	—
Sale of treasury shares	**—**	19	20
Sale of common stock	**36**	12	6
Dividends paid on common shares	**(75)**	(70)	(53)
Net payments and borrowings of short-term debt	**(480)**	(82)	4
Distribution to minority interest	**(14)**	—	—
Payments of Medium-Term notes	**(82)**	(207)	(93)
Other	**—**	(3)	(8)
Net cash flow provided by (used in) financing activities	**167**	31	(124)
Net increase in cash and cash equivalents	**32**	8	1
Cash and cash equivalents at beginning of period	**17**	9	8
Cash and cash equivalents at end of period	**$ 49**	$ 17	$ 9
Cash paid during the period for			
Interest (net of allowance for funds used during construction)	**$ 50**	$ 60	$ 73
Income taxes	**27**	23	15

See Notes to Consolidated Financial Statements.

Note 1
ACCOUNTING POLICIES AND METHODS OF APPLICATION
GENERAL

AGL Resources Inc. is an energy services holding company that 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).

Our issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by state and federal regulatory bodies, including state public service commissions and the SEC. Furthermore, a substantial portion of our consolidated assets, earnings and cash flow is derived from the operation of regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to us is subject to regulation. On April 1, 2004, we received approval from the SEC, under the Public Utility Holding Company Act of 1935 (PUHCA), for the renewal of our financing authority to issue securities through April 2007.

BASIS OF PRESENTATION

Our consolidated financial statements as of and for the periods ended December 31, 2004 include our accounts, the accounts of our majority-owned and controlled subsidiaries and the accounts of variable interest entities for which we are the primary beneficiary. This means that our accounts are combined with the subsidiaries' accounts. Certain amounts from prior periods have been reclassified to conform to the current-period presentation. Any intercompany profits and transactions between segments have been eliminated in consolidation; however, intercompany profits are not eliminated when such amounts are probable of recovery under the affiliates' rate regulation process. On November 30, 2004, we completed our acquisition of NUI Corporation (NUI); for more information see Note 2.

As of January 1, 2004, our consolidated financial statements include the accounts of SouthStar Energy Services LLC (SouthStar), a variable interest entity of which we are the primary beneficiary. Prior to January 1, 2004, we accounted for our 70% noncontrolling financial ownership interest in SouthStar using the equity method of accounting. Under the equity method, our ownership interest in SouthStar was reported as an investment within our consolidated balance sheets, and our share of SouthStar's earnings was reported in our consolidated statements of income as a component of other income. We utilize the equity method to account for and report investments where we exercise significant influence but do not control and where we are not the primary beneficiary as defined by Financial Accounting Standards Board (FASB) Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46). FIN 46 was revised in December 2003 (FIN 46R); consequently, as of January 1, 2004, we consolidated all SouthStar's accounts with our subsidiaries' accounts and eliminated any intercompany balances between segments. For more discussion of FIN 46R and the impact of its adoption on our consolidated financial statements, see Note 3.

Our equity method investments generally include entities where we have a 20% to 50% voting interest. In 2004, our investment in equity interests was composed of our 50% ownership in Saltville Gas Storage Company, LLC, a joint venture with a subsidiary of Duke Energy Corporation to develop a high-deliverability natural gas storage facility in Saltville, Virginia.

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.

Receivables and Allowance for Uncollectible Accounts

Our receivables consist of natural gas sales and transportation services billed to residential, commercial, industrial and other customers. Customers are billed monthly and accounts receivable are due within 30 days. For the majority of our receivables, we establish an allowance for doubtful accounts based on our collection experience. On certain other receivables where we are aware of a specific customer's inability or reluctance to pay, we record an allowance for doubtful accounts against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be different. Circumstances that could affect our estimates include, but are not limited to, customer credit issues, the level of natural gas prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible.

INVENTORIES

Our gas inventories 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, 2004, Sequent's natural gas inventory for reservoir and salt dome storage was recorded on an accrual basis. At December 31, 2004, 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 to be repaid at determinable dates to third parties, the inventory was recorded at fair value.

In Georgia's competitive environment, Marketers—that is, marketers who are certificated by the Georgia Public Service Commission (Georgia Commission) to sell retail natural gas in Georgia—including the Atlanta Gas Light Company (Atlanta Gas Light) 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 Atlanta Gas Light has under contract. Atlanta Gas Light assigns, on a monthly basis, the majority of the pipeline storage services that it has under contract to 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.

Goodwill

We adopted Statement of Financial Accounting Standards (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 $354 million of goodwill in our consolidated balance sheets, of which $157 million is related to our acquisition of NUI in November 2004 (see Note 2 for further details), $176 million is related to our acquisition of Virginia Natural Gas, Inc. (Virginia Natural Gas) in 2000, $14 million is related to our acquisition of Jefferson Island Storage & Hub, LLC (Jefferson Island) in October 2004 and $7 million is related to our acquisition of Chattanooga Natural Gas Company (Chattanooga Gas) in 1988.

We annually assess goodwill for impairment as of our fiscal year end and have not recognized any impairment charges for the years ended December 31, 2004, 2003 and 2002. We also assess goodwill for impairment if events or changes in circumstances may indicate an impairment of goodwill exists. We conduct this assessment principally through a review of financial results, changes in state and federal legislation and regulation, and the periodic regulatory filings for our regulated utilities.

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 deductions, primarily due to the benefits of tax depreciation since assets are generally depreciated for tax purposes over a shorter period of time than for book purposes. The tax effects of depreciation and other differences in those items are reported as deferred income tax assets or liabilities in our consolidated balance sheets. Investment tax credits of approximately $20 million were previously deducted for income tax purposes for Atlanta Gas Light, Chattanooga Gas and Elizabethtown Gas Company (Elizabethtown Gas), and have been deferred for financial accounting purposes and are being amortized as credits to income over the estimated lives of the related properties in accordance with regulatory requirements.

REVENUES

Distribution Operations

Revenues are recorded when services are provided to customers. Those revenues are based on rates approved by the regulatory state commissions of our utilities.

As required by the Georgia Commission, in July 1998, Atlanta Gas Light began billing Marketers for each residential, commercial and industrial customer's distribution costs in equal monthly installments. As required by the Georgia Commission, effective February 1, 2001, Atlanta Gas Light 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 results 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 revenue recognition. As a result, Atlanta Gas Light 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. Atlanta Gas Light had unrecovered seasonal rates of approximately $11 million as of December 31, 2004 and 2003 (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 Virginia Natural Gas and Chattanooga Gas 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. Virginia Natural Gas and Chattanooga Gas 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 tariffs for Elizabethtown Gas, Virginia Natural Gas and Chattanooga Gas contain weather normalization adjustments (WNA) that largely mitigate the impact of unusually cold or warm weather on customer billings and operating margin. The WNA'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.

Wholesale Services

Wholesale services' 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.

COST OF GAS

We charge our utility customers for the natural gas they consume using purchased gas adjustment (PGA) mechanisms set by the state regulatory agencies. Under the PGA, we 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 our 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 on the fair value of our common stock at the balance sheet date since these awards constitute a variable plan under APB 25.

The following table illustrates the effect on our net income and earnings per share had we applied the fair value recognition provisions of SFAS 123, "Accounting for Stock-Based Compensation" (SFAS 123):

In millions, except per share amounts	2004	2003	2002
Net income, as reported	**$ 153**	$ 128	$ 103
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effect	**(1)**	(1)	(2)
Pro-forma net income	**$ 152**	$ 127	$ 101
Earnings per share			
Basic — as reported	**$2.30**	$2.03	$1.84
Basic — pro-forma	**$2.28**	$2.02	$1.80
Fully diluted — as reported	**$2.28**	$2.01	$1.82
Fully diluted — pro-forma	**$2.26**	$2.00	$1.79

DEPRECIATION EXPENSE

Depreciation expense for distribution operations is computed by applying composite, straight-line rates (approved by the state regulatory agencies) to the investment of depreciable property. Excluding the utilities acquired from NUI, distribution operations' composite straight-line depreciation rate for depreciable property excluding transportation equipment was approximately 2.6% during 2004, 2.7% during 2003 and 2.8% during 2002. The composite, straight-line rate for the utilities acquired from NUI was 3.25%. As of May 1, 2002, the Georgia Commission required a decrease of depreciation rates for Atlanta Gas Light, which decreased depreciation expense by $6 million in 2002 and approximately $10 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.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC)

The applicable state regulatory agencies authorize Atlanta Gas Light, Elizabethtown Gas and Chattanooga Gas to record the cost of debt and equity funds as part of the cost of construction projects in our consolidated balance sheets and as AFUDC in the statements of consolidated income. The Georgia Commission has authorized a rate of 9.16%, the New Jersey Board of Public Utilities (NJBPU) has authorized a rate of 7.60% and the Tennessee Regulatory Authority (Tennessee Authority) has authorized a rate of 9.08%. The capital expenditures of our other regulated utilities do not qualify for AFUDC treatment.

COMPREHENSIVE INCOME

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

In 2004, our OCI decreased $6 million as a result of an $11 million increase in our unfunded pension obligation, net of a $7 million income tax benefit, which was offset by changes in the fair value of derivatives designated as cash flow hedges at SouthStar of $4 million. For more information on SouthStar's derivative financial instruments, see Note 4.

In 2003, our OCI increased $9 million as a result of an $8 million decrease in our unfunded pension obligation and $1 million for our 70% ownership interest in SouthStar's unrealized gain associated with its cash flow hedges. In 2002, our OCI decreased by $48 million, net of income tax benefit of $31 million, as a result of an increase in our unfunded pension obligation.

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. Fully 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 on 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 fully 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	2004	2003	2002
Denominator for basic earnings per share[1]	**66.3**	63.1	56.1
Assumed exercise of potential common shares	**0.7**	0.6	0.5
Denominator for fully diluted earnings per share	**67.0**	63.7	56.6

[1] Daily weighted average shares outstanding.

USE OF ACCOUNTING ESTIMATES

The preparation of our financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The most significant estimates include our regulatory accounting, the allowance for doubtful accounts, allowance for contingencies, pipeline replacement program accruals, environmental liability accruals, unbilled revenue recognition, pension obligations, derivative and hedging activities and purchase price allocations. Actual results could differ from those estimates.

Note 2
ACQUISITIONS
NUI CORPORATION

On November 30, 2004, we acquired all the outstanding shares of NUI for approximately $218 million, incurred $7 million of transaction costs and repaid $500 million of NUI's outstanding short-term debt. At closing, NUI had $709 million in debt and approximately $109 million of cash on its balance sheet (including the return of an interest escrow balance), bringing the net value of the acquisition to approximately $825 million. In connection with the acquisition, we incurred $23 million in employee-related restructuring charges, which include $16 million in severance costs, $4 million in change in control payments to certain NUI executives and the NUI Board of Directors, and $3 million of employee retention and relocation costs. The acquisition significantly expands our existing natural gas utilities, storage and pipeline businesses.

We funded the purchase price with a portion of the proceeds from our November 2004 common stock offering and proceeds from short-term borrowings under our commercial paper program. Additionally, NUI Utilities, Inc., a wholly owned subsidiary of NUI, had outstanding, at closing, $199 million of indebtedness pursuant to Gas Facility Revenue Bonds and $10 million in capital leases.

Our allocation of the purchase price is preliminary and is subject to change. The preliminary nature is a result of the timing of the acquisition, which occurred late in our fourth quarter. The amount currently allocated to property, plant and equipment represents our estimate of the fair value of the assets acquired. We based that estimate on a preliminary independent valuation counselor's report, which is expected to be finalized during the first quarter of 2005. The following table summarizes the fair values of the assets acquired and liabilities assumed on November 30, 2004:

In millions	Preliminary Fair Value
Purchase price	$ 825
Current assets	299
Property, plant and equipment	612
Other long-term assets	117
Goodwill	157
Current liabilities excluding debt	(108)
Short-term debt and capital leases	(502)
Long-term debt and capital leases	(207)
Other long-term liabilities	(143)
Equity	225

The excess of the purchase price over the fair value of the identifiable net assets acquired of $157 million was allocated to goodwill. We believe the acquisition resulted in the recognition of goodwill primarily because of the strength of NUI's underlying assets and the synergies and opportunities in the regulated utilities. Goodwill is not deductible for income tax purposes.

The table below reflects the unaudited pro-forma results of AGL Resources and NUI for the years ended December 31, 2004 and 2003 as if the acquisition and related financing had taken place on January 1. The pro-forma results are not necessarily indicative of the results that would have occurred if the acquisition had been in effect for the periods presented. In addition, the pro-forma results are not intended to be a projection of future results and do not reflect any synergies that might be achieved from combining the operations or eliminating significant expenses that NUI incurred in its last year of operations. Our results of operations for 2004 include one month of the acquired operations of NUI.

In millions, except per share amounts	2004	2003
Operating revenue	**$2,343**	$1,630
Income before cumulative effect of change in accounting principle	**105**	88
Net income	**105**	74
Net income per fully diluted share	**1.44**	1.05

JEFFERSON ISLAND

We acquired Jefferson Island from American Electric Power in October 2004 for $90 million, which included approximately $9 million of working gas inventory. We funded the acquisition with a portion of the net proceeds we received from our November 2004 common stock offering and borrowings.

Note 3
RECENT ACCOUNTING PRONOUNCEMENTS

ADOPTED IN 2004

FIN 46

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

In December 2003, the FASB revised FIN 46, delaying the effective dates for certain entities created before February 1, 2003, and making other amendments to clarify application of the guidance. For potential variable interest entities other than any special purpose entities, the FASB required FIN 46R to be applied no later than the end of the first fiscal year or interim reporting period ending after March 15, 2004. FIN 46R also requires certain disclosures of an entity's relationship with variable interest entities. We adopted FIN 46R effective January 1, 2004, resulting in the consolidation of SouthStar's accounts in our consolidated financial statements and the deconsolidation of the accounts related to our Trust Preferred Securities. FIN 46R also requires certain disclosures of an entity's relationship with variable interest entities.

Notes Payable to Trusts and Trust Preferred Securities In June 1997 and March 2001, we established AGL Capital Trust I and AGL Capital Trust II (Trusts) to issue our Trust Preferred Securities. The Trusts are considered to be special purpose entities under FIN 46 and FIN 46R since

- our equity in the Trusts is not considered to be sufficient to allow the Trusts to finance their own activities
- our equity investment is not considered to be at risk since the equity amounts were financed by the Trusts

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

The revisions in FIN 46R included specific guidance that instruments such as the call options included in our loan agreements with the Trusts do not constitute variable interests and should not be considered in the determination of the primary beneficiary. As a result, as of January 1, 2004 (when we adopted FIN 46R), we were required to exclude the accounts of the Trusts from our consolidated financial statements and to classify amounts payable to the Trusts as "Notes payable to Trusts" within long-term debt in our consolidated balance sheets as of December 31, 2004.

Due to deconsolidation of the Trusts, we included in our consolidated balance sheets at December 31, 2004, an asset of approximately $10 million representing our investment in the Trusts and a note payable to the Trusts totaling approximately $235 million, net of an interest rate swap of $3 million. We also removed $222 million related to the Trust Preferred Securities issued by the Trusts. The notes payable represent the loan payable to fund our investments in the Trusts of $10 million and the amounts due to the Trusts from the proceeds received from their issuances of Trust Preferred Securities of $222 million.

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

In March 2004, we executed an amended and restated partnership agreement with Piedmont that calls for SouthStar's earnings starting in 2004 to be allocated 75% to our subsidiary and 25% to Piedmont. Consequently, as of January 1, 2004 we consolidated all SouthStar's accounts with our subsidiaries' accounts and eliminated any intercompany balances between segments. We recorded Piedmont's portion of SouthStar's earnings as a minority interest in our consolidated statements of income, and we recorded Piedmont's portion of SouthStar's capital as a minority interest in our consolidated balance sheet. For all periods prior to February 18, 2003, SouthStar's earnings were allocated based on our 50% ownership interests in those periods. We determined that SouthStar is a variable interest entity as defined in FIN 46R because:

- Our equal voting rights with Piedmont are not proportional to our economic obligation to absorb 75% of any losses or residual returns from SouthStar.
- SouthStar obtains substantially all its transportation capacity for delivery of natural gas through our wholly owned subsidiary, Atlanta Gas Light.

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

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

However, as SouthStar's results of operations and financial condition were material in 2002 and 2003 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 in those prior periods, which we reported as other income (loss) in our statements of consolidated income, as those amounts were reported based on our ownership percentage.

In millions	Dec 31, 2003
Balance sheet	
Current assets	$174
Noncurrent assets	2
Current liabilities	75
Noncurrent liabilities	—

In millions	2003	2002
Income statement		
Revenues	$746	$630
Operating margin	124	115
Operating income	63	41
Net income from continuing operations	63	42

ISSUED BUT NOT YET ADOPTED IN 2004

In December 2004, the FASB issued SFAS No. 123(R), "Accounting for Stock Based Compensation" (SFAS 123R). SFAS 123R revises the guidance in SFAS 123 and supersedes APB 25, and its related implementation guidance. SFAS 123R focuses primarily on the accounting for share-based payments to employees in exchange for services, and it requires a public entity to measure and recognize compensation cost for these payments. Our share-based payments are typically in the form of stock option and restricted stock awards. The primary change in accounting is related to the requirement to recognize compensation cost for stock option awards that was not recognized under APB 25.

Compensation cost will be measured based on the fair value of the equity or liability instruments issued. For stock option awards, fair value would be estimated using an option pricing model such as the Black-Scholes model. SFAS 123R becomes effective as of the first interim or annual reporting period that begins after June 15, 2005, and therefore we will adopt SFAS 123R in the third quarter of 2005. We expect to recognize approximately $1 million of compensation cost during the last six months of 2005 related to our stock option awards. For a discussion of our stock-based compensation plans and agreements, see Note 7.

Note 4
RISK MANAGEMENT

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

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

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. We designated these interest rate swaps as fair value hedges and accounted for them using the "shortcut" method prescribed 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 the interest expense line item in the statement of consolidated income, only that portion of the hedge that is ineffective in achieving offsetting changes in fair value.

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

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

As of December 31, 2004, a notional principal amount of $175 million of these agreements effectively converted the interest expense associated with a portion of our senior notes and notes payable to Trusts from fixed rates to variable rates based on an interest rate equal to the London Interbank Offered Rate (LIBOR), plus a spread determined at the swap date. The fair value of these interest rate swaps was recorded as an asset of $1 million at December 31, 2004 and a liability of $4 million at December 31, 2003. For more information on the effective rates and maturity dates of our interest rate swaps, see Note 8.

In the third quarter of 2004, in anticipation of our $250 million Senior Note offering, we executed two treasury lock derivative instruments totaling $200 million to hedge our exposure to the potential increase in interest rates. These derivative instruments locked in a 10-year U.S. treasury rate of 4.45%. The rate on the 10-year treasury notes declined subsequent to the execution of these instruments and the pricing of our senior notes was set on a U.S. treasury rate of 4.81%. As a result, we terminated these derivative instruments and made an $8 million settlement payment to our counterparties, which we will amortize over the next 10 years through interest expense. The termination added approximately 30 basis points to the interest rate of our 6% Senior Notes.

COMMODITY-RELATED DERIVATIVE INSTRUMENTS

Elizabethtown Gas

Certain derivatives are utilized by Elizabethtown Gas for nontrading purposes to hedge the impact of market fluctuations on assets, liabilities and other contractual commitments. Pursuant to SFAS 133, such derivative products are marked-to-market each reporting period. Pursuant to regulatory requirements, realized gains and losses related to such derivatives are reflected in purchased gas costs and included in billings to customers. Unrealized gains and losses are reflected as a regulatory asset (loss) or liability (gain), as appropriate, on the consolidated balance sheet. As of December 31, 2004, Elizabethtown Gas had entered into New York Mercantile Exchange (NYMEX) futures contracts to purchase 9.7 billion cubic feet (Bcf) of natural gas at equivalent prices ranging from $3.609 to $8.291 per thousand cubic feet. Approximately 84% of these contracts have a duration of one year or less, and none of these contracts extend beyond October 2006.

Sequent Energy Management, L.P. (Sequent)

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

We attempt to mitigate substantially all the commodity price risk associated with Sequent's gas storage portfolio by locking in the economic margin at the time we enter into gas purchase transactions for our storage gas. We purchase gas for storage when 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 futures NYMEX contracts and other over-the-counter derivatives 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 futures contracts meet the definition of a derivative under SFAS 133 and are recorded at fair value in our consolidated balance sheets, with changes in fair value recorded in earnings in the period of change. The purchase, storage and sale of natural gas are accounted for on an accrual basis rather than on the mark-to-market basis we utilize for the derivatives used to mitigate the commodity price risk associated with our storage portfolio. This difference in accounting will result in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated.

At December 31, 2004, our commodity-related derivative financial instruments represented purchases (long) of 521 Bcf and sales (short) of 550 Bcf with approximately 93% of these scheduled to mature in less than two years and the remaining 7% in three to nine years. Excluding the cumulative effect of a change in accounting principle in 2003, our unrealized gains were $22 million in 2004, $1 million in 2003 and $4 million in 2002.

SouthStar

The commodity-related derivative financial instruments (futures, options and swaps) used by SouthStar manage exposures arising from changing commodity prices. SouthStar's objective for holding these derivatives is to utilize the most effective methods to reduce or eliminate the impacts of changing commodity prices. A significant portion of SouthStar's derivative transactions are designated as cash flow hedges under SFAS 133. Derivative gains or losses arising from cash flow hedges are recorded in OCI and are reclassified into earnings in the same period as the settlement of the underlying hedged item. Any hedge ineffectiveness, defined as when the gains or losses on the hedging instrument do not perfectly offset the losses or gains on the hedged item, is recorded in our cost of gas on our consolidated income statement in the period in which it occurs. SouthStar currently has only minimal hedge ineffectiveness.

SouthStar's remaining derivative instruments do not meet the hedge criteria under SFAS 133; therefore, changes in the fair value of these derivatives are recorded in earnings in the period of change. At December 31, 2004, the fair values of these derivatives were reflected in our consolidated financial statements as an asset of $9 million and a liability of $2 million. The maximum maturity of open positions is less than one year and represents purchases and sales of 8 Bcf.

CONCENTRATION OF CREDIT RISK

Atlanta Gas Light

Concentration of credit risk occurs at Atlanta Gas Light for amounts billed for services and other costs to its customers, which consist of 10 Marketers in Georgia. The credit risk exposure to Marketers varies seasonally, with the lowest exposure in the nonpeak summer months and highest exposure in the peak winter months. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. These retail functions include customer service, billing, collections, and the purchase and sale of natural gas. Atlanta Gas Light's tariff allows it to obtain security support in an amount equal to a minimum of two times a Marketer's highest monthly invoice.

Sequent

A concentration of credit risk exists at Sequent for amounts billed for services it provides to marketers and to utility and industrial customers. This credit risk is measured by 30-day receivable exposure plus forward exposure, which is highly concentrated in 20 of its customers. Sequent evaluates its counterparties using the Standard & Poor's Ratings Services (S&P) equivalent credit rating, which is determined by a process of converting the lower of the S&P or Moody's Investors Service (Moody's) rating to an internal rating ranging from 9.00 to 1.00, with 9.00 being equivalent to AAA/Aaa by S&P and Moody's and 1.00 being equivalent to D or Default by S&P and Moody's. A counterparty that does not have an external rating is assigned an internal rating based on the strength of its financial ratios.

The weighted average credit rating is obtained by multiplying each counterparty's assigned internal rating by the counterparty's credit exposure and the individual results are then summed for all counterparties. That total is divided by the aggregate total counterparties' exposure. This numeric value is converted to an S&P equivalent. At December 31, 2004, Sequent's top 20 counterparties represented approximately 57% of the total counterparty exposure of $328 million, derived by adding the top 20 counterparties' exposures and dividing by the total of Sequent's counterparties' exposures. Sequent's counterparties or the counterparties' guarantors had a weighted average S&P equivalent of an A- rating at December 31, 2004.

Sequent has established credit policies to determine and monitor the creditworthiness of counterparties, as well as the quality of pledged collateral. When we are engaged in more than one outstanding derivative transaction with the same counterparty and we also have a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of our credit risk. Sequent also uses other netting agreements with certain counterparties with whom we conduct significant transactions.

Note 5

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" (SFAS 71). Our regulatory assets and liabilities, and associated liabilities for our unrecovered pipeline replacement program (PRP) costs and unrecovered environmental remediation costs, are summarized in the table below:

In millions	Dec 31, 2004	Dec 31, 2003
Regulatory assets		
Unrecovered pipline replacement program (PRP) costs	**$361**	$432
Unrecovered environmental remediation costs	**200**	179
Unrecovered postretirement benefit costs	**14**	9
Unrecovered seasonal rates	**11**	11
Unrecovered PGA	**5**	—
Regulatory tax asset	**2**	3
Other	**20**	5
Total regulatory assets	**$613**	$639
Regulatory liabilities		
Accumulated removal costs	**$ 94**	$102
Unamortized investment tax credit	**20**	19
Deferred PGA	**37**	30
Regulatory tax liability	**14**	15
Other	**18**	3
Total regulatory liabilities	**183**	169
Associated liabilities		
PRP costs	**327**	405
Environmental remediation costs	**90**	83
Total associated liabilities	**417**	488
Total regulatory and associated liabilities	**$600**	$657

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 our regulatory assets are subject to review by the respective state regulatory commission during any future rate proceedings. In the event that the provisions of SFAS 71 were no longer applicable, we would recognize a write-off of net regulatory assets (regulatory assets less regulatory liabilities) that would result in a charge to net income, which would be classified as an extraordinary item. However, although the gas distribution industry is becoming increasingly competitive, our utility operations continue to recover their costs through cost-based rates established by the state regulatory commissions. As a result, we believe that the accounting prescribed under SFAS 71 remains appropriate. It is also our opinion that all regulatory assets are recoverable in future rate proceedings, and therefore, 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 environmental remediation costs and deferred 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. We have two rate riders that authorize the recovery of unrecovered environmental remediation costs. The environmental remediation cost rate rider for Atlanta Gas Light only allows for recovery of the costs incurred and the recovery period occurs over the five years after the expense is incurred. Environmental remediation costs associated with the investigation and remediation of Elizabethtown Gas' remediation sites located in the state of New Jersey are recovered under a Remediation Adjustment Clause and include the carrying cost on unrecovered amounts not currently in rates.

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 Georgia Commission to be administered by Atlanta Gas Light, requires, among other things, that it replace all bare steel and cast iron pipe in its system in the state of Georgia within a 10-year period, beginning October 1, 1998. Atlanta Gas Light identified, and provided notice to the Georgia Commission of, 2,312 miles of pipe to be replaced. Atlanta Gas Light has subsequently identified an additional 188 miles of pipe subject to replacement under this program. If Atlanta Gas Light does not perform in accordance with this order, it will be assessed certain nonperformance penalties. October 1, 2004 marked the beginning of the seventh year of the 10-year PRP.

The order also provides for recovery of all prudent costs incurred in the performance of the program, which Atlanta Gas Light has recorded as a regulatory asset. Atlanta Gas Light 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

Atlanta Gas Light has recorded a long-term regulatory asset of $337 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. Atlanta Gas Light has also recorded a current asset of $24 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 the last three years were

- $28 million in 2004
- $15 million in 2003
- $8 million in 2002

As of December 31, 2004, Atlanta Gas Light had recorded a current liability of $85 million, representing expected program expenditures for the next 12 months. Atlanta Gas Light anticipates that its capital expenditures for the PRP will end by June 30, 2008, unless we agree with the Georgia Commission to an extension of the program.

Atlanta Gas Light 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 Atlanta Gas Light to recover operation and maintenance costs in excess of those included in its current base rates, depreciation expense and an allowed rate of return on capital expenditures. In the near term, the primary financial impact to Atlanta Gas Light 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, Atlanta Gas Light is allowed the recovery of carrying costs on the under-recovered balance resulting from the timing difference.

ENVIRONMENTAL REMEDIATION COSTS

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites.

Atlanta Gas Light

The presence of coal tar and certain other byproducts of a natural gas manufacturing process used to produce natural gas prior to the 1950s has been identified at or near 13 former operating sites in Georgia and Florida. Atlanta Gas Light has active environmental remediation or monitoring programs in effect at 10 sites. Two of three sites in Florida and one Georgia site are currently in the preliminary investigation or engineering design phase. The required soil remediation at our Georgia sites is scheduled to be completed by June 2005. As of December 31, 2004, Atlanta Gas Light's remediation program was approximately 78% complete.

Atlanta Gas Light has historically reported estimates of future remediation costs for these former sites 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, Atlanta Gas Light is increasingly able to provide conventional engineering estimates of the likely costs of many elements at its former sites. These estimates contain various engineering uncertainties, and Atlanta Gas Light continuously attempts to refine and update these engineering estimates.

Our current engineering estimate projects costs associated with Atlanta Gas Light's engineering estimates and in-place contracts to be $36 million. This is a reduction of $30 million from last year's estimate of projected engineering and in-place contracts, which resulted from $50 million of program expenditures incurred in the year ended September 30, 2004. During the same 12-month period Atlanta Gas Light realized increases in its future cost estimates totaling $20 million related to

- an increase in the contract value at its Augusta, Georgia site for treatment of two areas and additional deep excavation of contaminants
- the addition of harbor sediment removal at its St. Augustine, Florida site
- an increase at its Savannah, Georgia site for phase 2 excavation and a partially offsetting decrease in engineering and oversight costs
- an increase in the program management costs due to legal matters, environmental regulatory activities and oversight costs for the extension of work at the Savannah and Augusta sites

The engineering estimate was $66 million in 2003, which was a reduction of $43 million from the 2002 estimate. The decrease was a result of $37 million of program expenditures incurred in the year ended September 30, 2003 and a $6 million reduction in future cost estimates. For those remaining elements of Atlanta Gas Light's environmental remediation program where it 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 these former operating sites is $14 million. Atlanta Gas Light estimates certain other costs related to administering the remediation program and remediation of sites currently in the investigation phase. Through January 2006, Atlanta Gas Light estimates the administrative costs to be $2 million.

For those sites currently in the investigation phase, Atlanta Gas Light's estimate for remediation is $9 million. This estimate is based on preliminary data received during 2004 with respect to the existence of contamination at those sites. Atlanta Gas Light's range of estimates for these sites is $4 million to $15 million. Atlanta Gas Light has accrued $9 million as this is its best estimate at this phase of the remediation process.

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 Atlanta Gas Light may be held liable but with respect to which it cannot reasonably estimate the amount. The liability also does not include certain potential cost savings as described above. As of December 31, 2004, the remediation expenditures expected to be incurred over the next 12 months are reflected as a current liability of $27 million. Atlanta Gas Light's environmental remediation cost liability is composed of the following elements:

In millions	Dec 31, 2004	Dec 31, 2003	2004 vs. 2003
Projected engineering estimates and in-place contracts[1]	**$36**	$ 66	$(30)
Estimated future remediation costs[1]	**14**	15	(1)
Administrative expenses[2]	**2**	3	(1)
Other expenses[2]	**9**	10	(1)
Cash payments for cleanup expenditures[3]	**(5)**	(11)	6
Environmental remediation cost liability	**$56**	$ 83	$(27)

[1] As of September 30, 2004 and September 30, 2003.

[2] For the respective calendar years.

[3] Expenditures during the three months ended December 31, 2004 and December 31, 2003.

The environmental remediation cost liability is included in a corresponding regulatory asset, which is a combination of accrued environmental remediation costs and unrecovered cash expenditures for investigation and cleanup costs. Atlanta Gas Light has three ways of recovering investigation and cleanup costs. First, the Georgia Commission has approved an environmental remediation cost 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. The environmental remediation cost recovery mechanism allows for recovery of expenditures over a five-year period subsequent to the period in which the expenditures are incurred. Atlanta Gas Light expects to collect $27 million in revenues over the next 12 months under the environmental remediation cost recovery rider, which is reflected as a current asset. The amounts recovered from the recovery rider during the last three years were

- $25 million in 2004
- $23 million in 2003
- $17 million in 2002

The second way to recover costs is by exercising the legal rights Atlanta Gas Light believes it has to recover a share of its costs from other potentially responsible parties, typically former owners or operators of these sites. There were no material recoveries from potentially responsible parties during 2004, 2003 or 2002.

The third way to recover costs is from the receipt of net profits from the sale of remediated property. In June 2004, a residential and retail development located in Savannah, Georgia and adjacent to a former remediation site was sold, resulting in a gain of $6 million. All gains on sales of remediated property are required to be shared 70% with ratepayers through a reduction to the regulatory asset. Consequently, the unrecovered environmental remediation costs were reduced by approximately $4 million.

Elizabethtown Gas

In New Jersey, Elizabethtown Gas is currently conducting remedial activities with oversight from the New Jersey Department of Environmental Protection. Although the actual total cost of future environmental investigation and remediation efforts cannot be estimated with precision, the range of reasonably probable costs is from $30 million to $116 million. As of December 31, 2004, we recorded a liability of $30 million, as this is the best estimate at this phase of the remediation process.

Elizabethtown Gas' prudently incurred remediation costs for the New Jersey properties have been authorized by the NJBPU to be recoverable in rates through its Remediation Adjustment Clause. As a result, Elizabethtown Gas has recorded a regulatory asset of approximately $34 million, inclusive of interest, as of December 31, 2004, reflecting the future recovery of both incurred costs and future remediation liabilities in the state of New Jersey. Elizabethtown Gas has also been successful in recovering a portion of remediation costs incurred in New Jersey from its insurance carriers and continues to pursue additional recovery. As of December 31, 2004, the variation between the amounts of the environmental remediation cost liability recorded on the consolidated balance sheet and the associated regulatory asset results from expenditures for environmental investigation and remediation exceeding recoveries from ratepayers and insurance carriers.

Other

We also own a former NUI remediation site in Elizabeth City, North Carolina, which is subject to an order by the North Carolina Department of Energy and Natural Resources. We do not have precise estimates for the cost of investigating and remediating this site, although preliminary estimates for these costs range from $4 million to $16 million. As of December 31, 2004, we have recorded a liability of $4 million related to this site. There is another site in North Carolina where investigation and remediation is probable, although no regulatory order exists and we do not believe costs associated with this site can be reasonably estimated. In addition, there are as many as six other sites with which NUI had some association, although no basis for liability has been asserted. We do not believe that costs to investigate and remediate these sites, if any, can be reasonably estimated at this time.

With respect to these costs we are currently pursuing or intend to pursue recovery from ratepayers, former owners and operators and insurance carriers. Although we have been successful in recovering a portion of these remediation costs from our insurance carriers, we are not able to express a belief as to the success of additional recovery efforts. We are working with the regulatory agencies to prudently manage our remediation costs so as to mitigate the impact of such costs on both ratepayers and shareholders.

Note 6

EMPLOYEE BENEFIT PLANS

PENSION BENEFITS

We sponsor two defined benefit retirement plans (Retirement Plan) for our eligible employees, the AGL Resources Inc. Retirement Plan (AGL Retirement Plan) and NUI Corporation Retirement Plan (NUI Retirement Plan). A defined benefit plan specifies the amount of benefits an eligible participant eventually will receive using information about the participant.

We generally calculate the benefits under the AGL 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 other than those participants who were employees as of July 1, 2000, and who were at least 50 years of age as of that date. We utilize a final average earnings benefit formula for participants who were both employees and 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.

NUI has a qualified noncontributing defined benefit retirement plan that covers substantially all its employees, other than Florida City Gas Company (Florida Gas) union employees, who participate in a union-sponsored multi-employer plan. Pension benefits are based on the number of years of credited service and on final average compensation.

Effective with our acquisition of NUI, we now administer the NUI Retirement Plan. Throughout 2005, we will maintain existing benefits for NUI employees, including participation in the NUI Retirement Plan. Beginning in 2006, eligible nonunion participants in the NUI Retirement Plan will become eligible to participate in the AGL Retirement Plan. Currently, participants of the NUI Retirement Plan have the option of receiving a lump sum distribution upon retirement, which is not permitted under the AGL Retirement Plan. However, the option to receive a lump sum payment will be provided for all benefits earned through December 31, 2005. The following tables present details about our pension plans:

In millions	AGL Retirement Plan Dec 31, 2004	AGL Retirement Plan Dec 31, 2003	NUI Retirement Plan Dec 31, 2004
Change in benefit obligation			
Benefit obligation at beginning of year	**$314**	$290	**$144**
Service cost	**5**	4	**—**
Interest cost	**19**	19	**1**
Actuarial loss	**21**	20	**—**
Benefits paid	**(19)**	(19)	**(1)**
Benefit obligation at end of year	**$340**	$314	**$144**
Change in plan assets			
Fair value of plan assets at beginning of year	**$259**	$208	**$108**
Actual return on plan assets	**26**	48	**4**
Employer contribution	**13**	22	**—**
Benefits paid	**(19)**	(19)	**(1)**
Fair value of plan assets at end of year	**$279**	$259	**$111**
Funded status			
Plan assets less benefit obligation at end of year	**$ (61)**	$ (55)	**$ (33)**
Unrecognized net loss	**108**	95	**—**
Unrecognized prior service benefit	**(11)**	(12)	**(3)**
Accrued pension cost	**$ 36**	$ 28	**$ (36)**
Amounts recognized in the statement of financial position consist of			
Prepaid benefit cost	**$ 43**	$ 34	**$ —**
Accrued benefit liability	**(7)**	(7)	**(36)**
Accumulated OCI	**(84)**	(66)	**—**
Net amount recognized at end of year	**$ (48)**	$ (39)	**$ (36)**

The accumulated benefit obligation (ABO) for our retirement plan and other information for our pension plans are indicated in the following tables:

In millions	AGL Retirement Plan Dec 31, 2004	AGL Retirement Plan Dec 31, 2003	NUI Retirement Plan Dec 31, 2004
Projected benefit obligation	**$340**	$314	**$144**
ABO	**327**	298	**118**
Fair value of plan assets	**279**	259	**111**
Increase (decrease) in minimum liability included in OCI	**18**	(14)	**—**
Components of net periodic benefit cost			
Service cost	**$ 5**	$ 4	**$ —**
Interest cost	**19**	19	**1**
Expected return on plan assets	**(23)**	(22)	**(1)**
Net amortization	**(1)**	(1)	**—**
Recognized actuarial (gain) loss	**5**	2	**—**
Net annual pension cost	**$ 5**	$ 2	**$ —**

The following table indicates our weighted average assumptions used to determine benefit obligations at the balance sheet date:

	AGL Retirement Plan Dec 31, 2004	AGL Retirement Plan Dec 31, 2003	NUI Retirement Plan Dec 31, 2004
Discount rate	**5.8%**	6.3%	**5.8%**
Rate of compensation increase	**4.0%**	4.5%	**4.0%**

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. We derive these expected long-term rates of return with the assistance of our investment advisors and generally base these rates 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. We base our expected allocation of plan assets on a diversified portfolio consisting of domestic and international equity securities, fixed income, real estate, private equity securities and alternative asset classes.

As of December 1, 2004, the discount rate used to determine NUI's opening balance sheet benefit obligation was 5.8%. This discount rate was also utilized to determine net periodic benefit cost for the month of December 2004. The following table presents the weighted average assumptions used to determine net periodic benefit cost at the beginning of the period, which was January 1, for the AGL Retirement Plan.

	AGL Retirement Plan Dec 31, 2004	AGL Retirement Plan Dec 31, 2003	NUI Retirement Plan Dec 31, 2004
Discount rate	**6.3%**	6.8%	**5.8%**
Expected return on plan assets	**8.8%**	8.8%	**8.5%**
Rate of compensation increase	**4.0%**	4.5%	**4.0%**

Our Retirement Plan's weighted average asset allocations at December 31, 2004 and 2003 and our target asset allocation ranges are as follows:

	Target Range Allocation of Assets	Actual Allocation on a Weighted Average Basis: AGL Retirement Plan 2004	AGL Retirement Plan 2003	NUI Retirement Plan 2004
Equity	40%–85%	**71%**	67%	**72%**
Fixed income	25%–50%	**25**	30	**28**
Real estate and other	0%–10%	**3**	—	**—**
Cash	0%–10%	**1**	3	**—**

The Retirement Plan Investment Committee (the Committee) 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 continue to more broadly diversify the Retirement 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 is 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 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 make a $1 million contribution to the pension plans in 2005.

POSTRETIREMENT BENEFITS

We sponsor two defined benefit postretirement health care plans for our eligible employees, the AGL Resources Inc. Postretirement Health Care Plan (AGL Postretirement Plan) and the NUI Corporation Postretirement Health Care Plan (NUI Postretirement Plan). Eligibility for these benefits is based on age and years of service.

The NUI Postretirement Plan provides certain medical and dental health care benefits to retirees, other than retirees of Florida City Gas Company, depending on their age, years of service and start date. The health care plans are contributory and NUI funded a portion of these future benefits through a Voluntary Employees' Beneficiary Association. Effective July 2000, NUI no longer offers postretirement benefits other than pensions for any new hires. In addition, NUI capped its share of costs at $500 per participant, per month for retirees under age 65, and at $150 per participant, per month for retirees over age 65. Effective with our acquisition of NUI, we acquired the NUI Postretirement Plan. Beginning in 2006, eligible participants in the NUI Postretirement Plan will become eligible to participate in the AGL Postretirement Plan.

The AGL Postretirement Plan covers all eligible AGL Resources employees who were employed as of June 30, 2002, if they reach retirement age while working for us. In addition, the state regulatory commissions have approved phase-ins that defer a portion of other postretirement benefits expense for future recovery. We recorded a regulatory asset of $14 million as of December 31, 2004 and $9 million as of December 31, 2003. In addition, we recorded a regulatory liability of $2 million as of December 31, 2004 and $2 million as of December 31, 2003.

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.

Effective July 2004, the AGL Postretirement Plan was amended to remove prescription drug coverage for Medicare-eligible retirees, effective January 1, 2006. Certain grandfathered NUI retirees participating in the NUI Postretirement Plan will continue receiving a prescription drug benefit for some period of time.

The AGL Postretirement Plan's accumulated postretirement benefit obligation decreased by approximately $24 million and net annual cost decreased by $2 million due to the elimination of prescription drug coverage for Medicare-eligible retirees. The 2004 net periodic postretirement benefit cost reflects both the plan amendment to remove prescription drug coverage under the AGL Postretirement Plan, described above, and the federal subsidy for NUI grandfathered retirees. The following tables present details about our postretirement benefits:

In millions	AGL Postretirement Plan Dec 31, 2004	Dec 31, 2003	NUI Postretirement Plan Dec 31, 2004
Change in benefit obligation			
Benefit obligation at beginning of year	**$134**	$129	**$ 23**
Service cost	**1**	1	**—**
Interest cost	**7**	8	**—**
Plan amendments	**(24)**	—	**—**
Actuarial loss	**(12)**	6	**—**
Benefits paid	**(8)**	(10)	**—**
Benefit obligation at end of year	**$ 98**	$134	**$ 23**
Change in plan assets			
Fair value of plan assets at beginning of year	**$ 44**	$ 38	**$ 9**
Actual return on plan assets	**5**	8	**—**
Employer contribution	**8**	8	**—**
Benefits paid	**(8)**	(10)	**—**
Fair value of plan assets at end of year	**$ 49**	$ 44	**$ 9**
Funded status			
ABO in excess of plan assets	**$ (49)**	$ (90)	**$(14)**
Unrecognized loss	**30**	44	**—**
Unrecognized transition amount	**1**	1	**—**
Unrecognized prior service cost (benefit)	**(26)**	(6)	**—**
Accrued benefit cost	**$ (44)**	$ (51)	**$(14)**
Amounts recognized in the statement of financial position consist of			
Prepaid benefit cost	**$ —**	$ —	**$ —**
Accrued benefit liability	**(44)**	(51)	**(14)**
Accumulated OCI	**—**	—	**—**
Net amount recognized at end of year	**$ (44)**	$ (51)	**$(14)**

The following table presents details on the components of our net periodic benefit costs at the balance sheet data:

In millions	AGL Postretirement Plan 2004	2003	NUI Postretirement Plan 2004
Service cost	**$ 1**	$ 1	**$—**
Interest cost	**7**	8	**—**
Expected return on plan assets	**(3)**	(3)	**—**
Amortization of transition amount	**(2)**	—	**—**
Amortization of regulatory asset	**1**	2	**—**
Net periodic postretirement benefit cost	**$ 4**	$ 8	**$—**

The following table presents our weighted average assumptions used to determine benefit obligations at the beginning of the period, which was January 1 for the AGL Postretirement Plan and December 1 for the NUI Postretirement Plan:

	AGL Postretirement Plan 2004	2003	NUI Postretirement Plan 2004
Discount rate	**5.8%**	6.3%	**5.8%**

The following table presents our weighted average assumptions used to determine net periodic benefit cost:

	AGL Postretirement Plan 2004	2003	NUI Postretirement Plan 2004
Discount rate	**6.3%**	6.8%	**5.8%**
Expected return on plan assets	**8.8%**	8.8%	**2.0%**
Rate of compensation increase	**4.0%**	4.5%	**—**

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:

Assumed Health Care Cost Trend Rates at December 31,	AGL Postretirement Plan Pre-Medicare Cost (pre–65 years old) 2004	2003	Post-Medicare Cost (post–65 years old) 2004	2003
Health care costs trend assumed for next year	**11.3%**	10.0%	**11.3%**	12.0%
Rate to which the cost trend rate gradually declines	**2.5%**	5.0%	**2.5%**	5.0%
Year that the rate reaches the ultimate trend rate	**2006**	2010	**2006**	2011

Assumed Health Care Cost Trend Rates at December 31,	NUI Postretirement Plan 2004
Health care costs trend assumed for next year	**9.0%**
Rate to which the cost trend rate gradually declines	**5.0%**
Year that the rate reaches the ultimate trend rate	**2008**

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:

In millions	One-percentage-point Increase	Decrease
Effect on total of service and interest cost[1]	$1	$(1)
Effect on accumulated postretirement benefit obligation[1]	6	(6)

[1] There were no material amounts for the NUI Postretirement benefit obligation or interest costs.

The following table presents expected benefit payments covering the periods 2005 through 2014 for our qualified pension plans and postretirement health care plans. There will be benefit payments under these plans beyond 2014.

For the year ended Dec 31, In millions	AGL Resources' Plans Pension Plan	AGL Resources' Plans Postretirement Health Care Plans	NUI's Plans Pension Plan	NUI's Plans Postretirement Health Care Plans
2005	$ 19	$ 8	$17	$2
2006	18	7	8	2
2007	18	7	8	2
2008	18	7	9	2
2009	19	7	9	2
2010–2014	101	34	61	9

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 postretirement benefit plan's weighted average asset allocations for 2004, 2003 and 2002 and our target asset allocation ranges are as follows:

	Target Asset Allocation Ranges	2004	2003
Equity	40%–85%	**67%**	59%
Fixed income	25%–50%	**32%**	40%
Real estate and other	0%–10%	**–%**	–%
Cash	0%–10%	**1%**	1%

EMPLOYEE SAVINGS PLAN BENEFITS

We sponsor the Retirement Savings Plus Plan (RSP), a defined contribution benefit plan that allows eligible participants to make contributions up to specified limits to its account. Under the RSP, we made matching contributions to participant accounts in the following amounts:

- $5 million in 2004
- $4 million in 2003
- $4 million in 2002

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 were not significant.

Effective December 1, 2004, all NUI employees who were participating in NUI's qualified defined contribution benefit plan were eligible to participate in the RSP, and those who were participants in NUI's nonqualified defined contribution plan became eligible to participate in the NSP.

Note 7

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 7.9 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 grants of nonqualified stock options and restricted stock to new-hire officers. The Officer Plan authorizes the issuance of up to 600,000 shares of our common stock.
- SARs have been 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 of a share of our common stock on the date of exercise and the SAR base value. A total of 26,863 SARs currently are outstanding.
- We amended the Non-Employee Directors Equity Compensation Plan (Directors Plan), in which all nonemployee directors participate, to eliminate the granting of stock options effective December 2002. As a result, the Directors Plan now provides solely 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—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
Granted	**103,900**	**29.72**
Exercised	**(1,050,053)**	**20.90**
Forfeited	**(390,745)**	**22.44**
Outstanding—December 31, 2004	**2,174,072**	**$23.23**

Information about outstanding and exercisable options as of December 31, 2004 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	2,199	5.0	$16.99	2,199	$16.99
$17.50 to $19.99	201,640	3.8	$18.85	199,973	$18.84
$20.00 to $24.10	1,164,156	5.5	$21.23	1,126,827	$21.17
$24.11 to $30.00	751,936	8.4	$26.97	325,737	$26.91
$30.01 to $34.00	54,141	6.2	$31.07	3,524	$31.20
Outstanding—December 31, 2004	**2,174,072**	**6.4**	**$23.23**	**1,658,260**	**$22.04**

Summarized below are outstanding options that are fully exercisable:

	Number of Options	Weighted Average Exercise Price
Exercisable — December 31, 2002	2,483,756	$20.07
Exercisable — December 31, 2003	2,154,877	$20.47
Exercisable — December 31, 2004	**1,658,260**	**$22.04**

Our stock-based employee compensation plans are accounted for under the recognition and measurement principles of 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 on the fair value of our common stock at the balance sheet date since these awards constitute a variable plan under APB 25.

In accordance with the fair value method of determining compensation expense, we utilized the Black-Scholes pricing model and the estimate below for the years ended December 31, 2004, 2003 and 2002:

	2004	2003	2002
Expected life (years)	**7**	7	7
Interest rate	**3.7%**	3.8%	4.6%
Volatility	**16.9%**	19.2%	19.2%
Dividend yield	**3.9%**	4.2%	5.0%
Fair value of options granted	**$3.72**	$3.75	$2.92

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 million in 2004, $8 million in 2003 and $2 million in 2002.

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 general, a performance unit is an award to receive an equal number of shares of company common stock or an equivalent value of cash subject to the achievement of certain pre-established performance criteria.

In February 2002, we granted to a select group of executives a total of 1.5 million in performance units with a performance measurement period that ended December 31, 2004. The amount actually earned would be based on the highest average closing price of our common stock over any 10 consecutive trading days during the performance measurement period and could range from a minimum of 10% to 100% of the granted units. The performance units were subject to certain transfer restrictions and forfeiture upon termination of employment. In addition, during a portion of the performance measurement period, performance units were eligible for dividend credits based on vested performance units. Of the 1.5 million units that were granted, only 1 million units were eligible for vesting at December 31, 2004. Upon vesting, the performance units were payable in shares of our common stock, provided, however, at the election of the participant, up to 50% was payable in cash.

At December 31, 2004, based on the highest average closing price over any 10 consecutive trading days during the performance measurement period, only 18.31% of units were vested, representing an aggregate of 198,000 units, including accrued dividends. These units were valued at our closing stock price on December 31, 2004 of $33.24 per unit representing a value of $6.6 million. The total value of the awards in the amount of $6.6 million was paid out as follows:

- $2.6 million paid in cash
- $2.8 million withheld to cover applicable taxes
- 35,342 shares of common stock with an approximate value of $1.2 million

In November 1999, we granted performance units that 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. We did not grant performance units in 2004 or 2003.

STOCK APPRECIATION RIGHTS

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 2004 and 2003 was immaterial. The following table summarizes activity related to grants of SARs:

	Number of SARs	Weighted Average Exercise Price
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	$23.70
Issued	**—**	**$ —**
Exercised	**(60,262)**	**23.70**
Forfeited	**(72,832)**	**23.50**
Outstanding as of December 31, 2004	**26,863**	**$24.24**

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:

	2004	2003	2002
Employees	**51,300**	244,128	30,000
Nonemployee directors	**8,727**	12,152	1,410
Total	**60,027**	256,280	31,410
Weighted average fair value at year end	**$32.45**	$27.15	$23.19

In addition, 104,000 of the 256,280 shares awarded to selected employees in 2003 vested in 2004. The remaining nonvested shares were contingent upon our achievement of selected cash flow performance measures over the one-year performance measurement period. Recipients were entitled to vote and receive dividends on stock awards. The shares were subject to certain transfer restrictions and are forfeited upon termination of employment, absent a change of control.

EMPLOYEE STOCK PURCHASE PLAN

We have 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. The ESPP currently allows for the purchase of 600,000 shares. As of December 31, 2004, our employees have purchased 73,254 shares leaving 526,746 shares available for purchase. The ESPP was adopted by our Board in 2001, with an initial term of four years that expired January 31, 2005. Our Board of Directors approved an amendment to the ESPP, subject to shareholder approval at the next annual meeting of shareholders, to extend the term of the ESPP for a 10-year period effective January 31, 2005. More information about the ESPP is presented below:

	2004	2003	2002
Shares purchased on the open market	**35,789**	24,871	12,594
Average per share purchase price	**$ 25.20**	$ 22.08	$ 23.22
Purchase price discount paid	**$159,144**	$97,400	$44,024

Note 8
FINANCING

Dollars in millions	Year(s) Due	Interest Rate as of Dec 31, 2004	Outstanding as of: Dec 31, 2004	Outstanding as of: Dec 31, 2003
Short-term debt				
Commercial paper[1]	2005	**2.5%**	**$ 314**	$ 303
Current portion of long-term debt	—	**—**	**—**	77
Sequent line of credit[2]	2005	**2.5**	**18**	3
Current portion of capital leases	2005	**4.9**	**2**	—
Total short-term debt[3]		**2.5%**	**$ 334**	$ 383
Long-term debt — net of current portion				
Medium-Term notes				
Series A	2021	**9.1%**	**$ 30**	$ 30
Series B	2012–2022	**8.3–8.7**	**61**	61
Series C	2014–2027	**6.6–7.3**	**117**	122
Senior notes	2011–2013	**4.5–7.1**	**975**	525
Gas facility revenue bonds, net of unamortized issuance costs	2022–2033	**1.9–6.4**	**199**	—
Notes payable to Trusts	2037–2041	**8.0–8.2**	**232**	—
Trust Preferred Securities	2037–2041	**—**	**—**	222
Capital leases	2013	**4.9**	**8**	—
AGL Capital interest rate swaps	2011–2041	**3.6–5.2**	**1**	(4)
Total long-term debt[3]		**6.0%**	**$1,623**	$ 956
Total short-term and long-term debt[3]		**5.4%**	**$1,957**	$1,339

[1] The daily weighted average rate was 1.6% for 2004 and 1.3% for 2003.

[2] The daily weighted average rate was 2.0% for 2004 and 1.6% for 2003.

[3] The weighted average interest rate excludes capital leases but includes interest rate swaps, if applicable.

SHORT-TERM DEBT

Our short-term debt at December 31, 2004 and 2003 was composed of borrowings under our commercial paper program, which consisted of short-term, unsecured promissory notes with maturities ranging from 3 to 56 days, Atlanta Gas Light's Medium-Term notes with maturities within one year, current portions of our capital lease obligations, Sequent's line of credit and SouthStar's line of credit.

Commercial Paper

In September 2004, we amended our credit facility that supports our commercial paper program (Credit Facility). Under the terms of the amendment, the Credit Facility has been extended from May 26, 2007 to September 30, 2009. The aggregate principal amount available under the Credit Facility has been increased from $500 million to $750 million and the cost of borrowing has been decreased relative to the prior credit agreements. In addition, our option to increase the aggregate cumulative principal amount available for borrowing on not more than one occasion during each calendar year during the term of the Credit Facility has been increased from $200 million to $250 million.

Sequent Line of Credit

In June 2004, Sequent's $25 million unsecured line of credit was extended to July 2005. 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%.

SouthStar Line of Credit

In April 2004, SouthStar amended its $75 million revolving line of credit, which is used to meet seasonal working capital needs. SouthStar's line of credit is scheduled to expire in April 2007 and is not guaranteed by us. At December 31, 2004, there were no amounts outstanding under this facility.

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, Senior Notes, Gas Facility Revenue Bonds, notes payable to Trusts and capital leases. The notes are unsecured and rank on parity with all our other unsecured indebtedness. Our annual maturities of long-term debt are as follows:

- no maturities in 2005–2010
- $1,623 million in 2011 and beyond

Senior Notes

In February 2001, we issued $300 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. 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 million to effectively convert a portion of the fixed-rate interest obligation on the $300 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, 2004 was 5.2%. These interest rate swaps expire January 14, 2011, unless terminated earlier. For more information on our interest rate swaps, see Note 4.

In July 2003, we issued $225 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 approximately $204 million of Medium-Term notes as well as approximately $20 million of short-term debt.

In September 2004, we issued $250 million in Senior Notes with a maturity of October 1, 2034. The Senior Notes have an interest rate of 6.00% payable on April 1 and October 1 of each year, beginning April 1, 2005 with interest accruing from September 27, 2004.

In December 2004, we issued $200 million in Senior Notes with a maturity of January 15, 2015. The Senior Notes have an interest rate of 4.95% payable on January 15 and July 15 of each year, beginning July 15, 2005 with interest accruing from December 20, 2004. We used the net proceeds from both of the senior notes issuances in 2004 to repay commercial paper borrowings and for general corporate purposes.

The trustee with respect to all of the above-referenced senior notes is the Bank of New York Trust Company, N.A., pursuant to an indenture dated February 20, 2001. We fully and unconditionally guarantee all our senior notes.

Gas Facility Revenue Bonds

NUI Utilities, Inc., a wholly owned subsidiary of NUI, had outstanding at closing $200 million of indebtedness pursuant to Gas Facility Revenue Bonds. We do not guarantee or provide any other form of security for the repayment of this indebtedness. NUI Utilities is party to a series of loan agreements with the New Jersey Economic Development Authority (NJEDA) pursuant to which the NJEDA has issued four series of Gas Facility Revenue Bonds:

- $46 million of bonds at 6.35%, due October 1, 2022
- $20 million of bonds at 6.4%, due October 1, 2024
- $39 million of bonds at variable rates, due June 1, 2026 (Variable Bonds)
- $55 million of bonds at 5.7%, due June 1, 2032
- $40 million of bonds at 5.25%, due November 1, 2033

The Variable Bonds contain a provision whereby the holder can "put" the bonds back to the issuer. In 1996, NUI Utilities executed a long-term Standby Bond Purchase Agreement (SBPA) with a syndicate of banks, which was amended and restated on June 12, 2001. Under the terms of the SBPA, as further amended, The Bank of New York Trust Company, N.A. (Bank of New York) is obligated under certain circumstances to purchase Variable Bonds that are tendered by the holders thereof and not remarketed by the remarketing agent. Such obligation of the Bank of New York would remain in effect until the expiration of the SBPA, unless it is extended or earlier terminated.

The terms of the SBPA restrict the payment of dividends by NUI Utilities to an amount based, in part, on the earned surplus of NUI Utilities. On May 19, 2004, NUI Utilities and the Bank of New York amended the SBPA to eliminate the effect of NUI Utilities' settlement with the NJBPU and the estimated refunds to customers in Florida on the earned surplus of NUI Utilities. In addition, the amendment extended the expiration date of the SBPA to June 29, 2005.

If the SBPA is not further extended beyond June 29, 2005, in accordance with the terms of the Variable Bonds, all the Variable Bonds would be subject to mandatory tender at a purchase price of 100% of the principal amount, plus accrued interest, to the date of tender. In such case, any Variable Bonds that are not remarketable by the remarketing agent will be purchased by the Bank of New York.

Beginning six months after the expiration or termination of the SBPA, any Variable Bonds still held by the bank must be redeemed or purchased by NUI Utilities in 10 equal, semi-annual installments. In addition, while the SBPA is in effect, any tendered Variable Bonds that are purchased by the bank and not remarketed within one year must be redeemed or purchased by NUI Utilities at such time, and every six months thereafter, in 10 equal, semi-annual installments.

As of December 31, 2004, the aggregate principal and accrued interest on the outstanding Variable Bonds totaled approximately $39 million. Principal and any unpaid interest on the outstanding Variable Bonds are due on June 1, 2026, unless the put option is exercised before that time.

Notes Payable to Trusts

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 million 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 issued by us. 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.

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 million 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 issued by us. The proceeds from the issuance were used to refinance a portion of our 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. Additionally we entered into interest rate swaps to effectively convert a portion of the fixed-rate interest obligation on our notes payable to Trusts to a variable-rate obligation. The effective variable interest rate at December 31, 2004 was 3.6%. For more information on our interest rate swaps, see Note 4.

The trustee is the Bank of New York with respect to the 8.17% capital securities pursuant to an indenture dated June 11, 1997, and with respect to the 8.00% capital securities pursuant to an indenture dated May 21, 2001. We fully and unconditionally guarantee all our Trusts' 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.

Capital Leases

Our capital leases consist primarily of a sale/leaseback transaction completed in 2002 by Florida Gas related to its gas meters and other equipment and will be repaid over 11 years. Pursuant to the terms of the lease agreement, Florida Gas is required to insure the leased equipment during the lease term. In addition, at the expiration of the lease term, Florida Gas has the option to purchase the leased meters from the lessor at their fair market value.

DEFAULT EVENTS

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%. 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.

Note 9
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, 2004, 1.0 million shares of Class A Junior Participating Preferred Stock were reserved for issuance under that plan.

EQUITY OFFERING

On November 18, 2004, we completed our public offering of 11.04 million shares of common stock. We priced the offering at $31.01 per share and generated net proceeds of approximately $332 million, which we used to purchase the outstanding capital stock of NUI and to repay short-term debt incurred to fund the purchase of Jefferson Island. In February 2003, we completed our public offering of 6.4 million shares of common stock. The offering generated net proceeds of approximately $137 million, which we used to repay outstanding short-term debt and for general corporate purposes.

DIVIDENDS

Our common shareholders may receive 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 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 under the PUHCA on our payment of dividends out of capital or unearned surplus without prior permission from the SEC

Under Georgia law, the payment of dividends to the holders of our common stock is limited to our legally available assets and subject to the prior payment of dividends on any outstanding shares of preferred stock and junior preferred stock. Our assets 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 shareholders receiving the dividends

We announced the following increases in our cash dividends payable on our common stock:

- In February 2005, we announced a 7% increase in our common stock dividend. The increase raised the quarterly dividend from $0.29 per share to $0.31 per share, for an indicated annual dividend of $1.24 per share.
- In April 2004, we announced a 4% increase in our common stock dividend, raising the quarterly dividend from $0.28 per share to $0.29 per share which indicated an annual dividend of $1.16 per share.
- In April 2003, we announced a 4% increase in our common stock dividend from $0.27 per share to $0.28 per share, which indicated an annual dividend of $1.12.

Note 10

COMMITMENTS AND CONTINGENCIES

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

We have incurred various contractual obligations and financial commitments in the normal course of our operations and financing activities. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements. These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related revenue-producing activities. We calculate any expected pension contributions using an actuarial method called the projected unit credit cost method, and pursuant to these calculations, we expect to make a $1 million pension contribution in 2005. The following table illustrates our expected future contractual cash obligations as of December 31, 2004:

In millions	Total	Payments Due Before December 31, 2005	2006 & 2007	2008 & 2009	2010 & Thereafter
Long-term debt[1,2]	$1,623	$ —	$ 2	$ 2	$1,619
Pipeline charges, storage capacity and gas supply[3,4]	1,051	258	262	179	352
Short-term debt[2]	334	334	—	—	—
PRP costs[5]	327	85	162	80	—
Operating leases[6]	170	27	39	29	75
ERC[5]	90	27	10	12	41
Commodity and transportation charges	20	19	1	—	—
Total	$3,615	$750	$476	$302	$2,087

[1] Includes $232 million of notes payable to Trusts redeemable in 2006 and 2007.

[2] Does not include the interest expense associated with the long-term and short-term debt.

[3] Charges recoverable through a PGA mechanism or alternatively billed to Marketers. Also includes demand charges associated with Sequent.

[4] A subsidiary of NUI entered into two 20-year agreements for the firm transportation and storage of natural gas during 2003 with the annual demand charges aggregate of approximately $5 million. As a result of our acquisition of NUI and in accordance with SFAS 141, the contracts were valued at fair value. The $38 million currently allocated to accrued pipeline demand charges on our consolidated balance sheets represent our estimate of the fair value of the acquired contracts. The liability will be amortized over the remaining life of the contracts.

[5] Charges recoverable through rate rider mechanisms.

[6] 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.

SouthStar has natural gas purchase commitments related to the supply of minimum natural gas volumes to its customers. These commitments are priced on an index plus premium basis. At December 31, 2004, SouthStar had obligations under these arrangements for 11.2 Bcf for the year ending December 31, 2005. This obligation is not included in the above table. SouthStar also had capacity commitments related to the purchase of transportation rights on interstate pipelines.

We also have incurred various contingent financial commitments in the normal course of business. Contingent financial commitments represent obligations that become payable only if certain predefined events occur, such as financial guarantees, and include the nature of the guarantee and the maximum potential amount of future payments that could be required of us as the guarantor. The following table illustrates our expected contingent financial commitments as of December 31, 2004:

		Commitments Due Before December 31,			
In millions	Total	2005	2006 & 2007	2008 & 2009	2010 & Thereafter
Guarantees[1]	$ 7	$ 7	$—	$—	$—
Standby letters of credit and performance/surety bonds	12	12	—	—	—
Total	$19	$19	$—	$—	$—

[1] We provide a guarantee on behalf of our subsidiary, SouthStar. We guarantee 70% of SouthStar's obligations to Southern Natural Gas Company (Southern Natural) under certain agreements between the parties up to a maximum of $7 million if SouthStar fails to make payment to Southern Natural. We have certain guarantees that are recorded on our consolidated balance sheet that would not cause any additional impact on our financial statements beyond what was already recorded.

RENTAL EXPENSE AND SUBLEASE INCOME

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

In millions	2004	2003	2002
Rental expense	**$22**	$22	$20
Sublease income	**—**	—	(2)

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. Changes to the status of previously disclosed litigation are as follows:

NUI Shareholder Complaint

In September 2004, a shareholder class action complaint (Complaint) was filed in a civil action captioned *Green Meadows Partners, LLP on behalf of itself and all others similarly situated v. Robert P. Kenney, Bernard S. Lee, Craig G. Mathews, Dr. Vera King Farris, James J. Forese, J. Russell Hawkins, R. Van Whisnand, John Kean, NUI and the Company,* pending in the Superior Court of the State of New Jersey, County of Somerset, Law Division. The Complaint, brought on behalf of a potential class of the stockholders of NUI, names as defendants all of the directors of NUI (Individual Defendants), NUI and the Company.

The Complaint alleges that purported financial incentives in the form of change of control payments and indemnification rights created a conflict of interest on the part of certain of the Individual Defendants in evaluating a possible sale of NUI. The Complaint further alleges that the Individual Defendants, aided and abetted by the Company, breached fiduciary duties owed to the plaintiff and the potential class. The Complaint demands judgment (i) determining that the action is properly maintainable as a class action, (ii) declaring that the Individual Defendants breached fiduciary duties owed to the plaintiff and the potential class, aided and abetted by the Company, (iii) enjoining the sale of NUI, or if consummated, rescinding the sale, (iv) eliminating the $7.5 million break-up fee with the Company, (v) awarding the plaintiff and the potential class compensatory and/or rescissory damages, (vi) awarding interest, attorney's fees, expert fees and other costs, and (vii) granting such other relief as the Court may find just and proper.

On October 12, 2004, we reached an agreement in principle with Green Meadows Partners, LLP to settle this litigation. The settlement called for NUI to provide certain additional information and disclosures to its shareholders, as reflected in the "Additional Disclosure" section of NUI's proxy statement supplement, filed on October 12, 2004 with the SEC. In addition, as part of the settlement, NUI and the Company consented to a settlement class that consists of persons holding shares of NUI common stock at any time from July 15, 2004 until November 30, 2004, and we agreed to pay plaintiff's attorney's fees and costs in the amount of $285,000. No part of these attorney's fees or costs will be paid out of funds that would otherwise have been paid to NUI's shareholders.

On December 22, 2004, the trial court entered an order conditionally certifying a class for settlement purposes and designating the Plaintiff as a Settlement Class representative. The trial court's order also established deadlines for Defendants to provide notice to the Settlement Class, for Settlement Class members to object to the settlement and for a final Settlement Hearing.

Note 11
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, 2004		
Long-term debt including current portion	**$1,623**	**$1,816**
As of December 31, 2003		
Long-term debt including current portion	1,033	1,166

The estimated fair values are determined based on interest rates that are currently available for issuance of debt with similar terms and remaining maturities. For the notes payable to Trusts, we used quoted market prices 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, 2004. 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 4.

Note 12
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 5). 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. Components of income tax expense shown in the statements of consolidated income are as follows:

In millions	2004	2003	2002
Included in expenses			
Current income taxes			
Federal	**$25**	$20	$(19)
State	**1**	13	(4)
Deferred income taxes			
Federal	**60**	52	79
State	**5**	3	3
Amortization of investment tax credits	**(1)**	(1)	(1)
Total	**$90**	$87	$ 58

The reconciliations between the statutory federal income tax rate, the effective rate and the related amount of tax for the years ended December 31, 2004, 2003 and 2002 are presented below:

Dollars in millions	2004 Amount	2004 % of Pretax Income	2003 Amount	2003 % of Pretax Income	2002 Amount	2002 % of Pretax Income
Computed tax expense	**$85**	**35.0%**	$78	35.0%	$56	35.0%
State income tax, net of federal income tax benefit	**9**	**3.5**	8	3.8	4	2.4
Amortization of investment tax credits	**(1)**	**(0.6)**	(1)	(0.6)	(1)	(0.8)
Flexible dividend deduction	**(2)**	**(0.6)**	(1)	(0.6)	(2)	(0.9)
Other — net	**(1)**	**(0.2)**	3	1.4	1	0.3
Total income tax expense	**$90**	**37.1%**	$87	39.0%	$58	36.0%

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 utilities' 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 5). Our deferred tax asset includes an additional pension liability of $34 million, which increased $7 million from 2003 in accordance with SFAS 109 (see Note 6).

As indicated in the table below, our deferred tax assets and liabilities include certain items we acquired from NUI. We have provided a valuation allowance for some of these items that reduces our net deferred tax assets to amounts we believe are more likely than not to be realized in future periods. With respect to our continuing operations, we have net operating losses in various jurisdictions. Components that give rise to the net accumulated deferred income tax liability are as follows:

In millions	As of Dec 31, 2004	As of Dec 31, 2003
Accumulated deferred income tax liabilities		
Property — accelerated depreciation and other property-related items	**$323**	$294
Other	**238**	125
Total accumulated deferred income tax liabilities	**561**	419
Accumulated deferred income tax assets		
Deferred investment tax credits	**8**	7
Deferred pension additional minimum liability	**34**	27
Net operating loss — NUI[1]	**31**	—
Net operating loss — Virginia Gas Company[2]	**6**	—
Capital loss carryforward	**5**	—
Alternative minimum tax credit[3]	**7**	—
Other	**41**	9
Total accumulated deferred income tax assets	**132**	43
Valuation allowances	**(8)**	—
Total accumulated deferred income tax assets, net of valuation allowance	**124**	43
Net accumulated deferred tax liability	**$437**	$376

[1] Includes NUI's federal net operating loss carryforwards of approximately $79 million that expire in 2024.

[2] Includes Virginia Gas Company's $18 million pre-acquisition net operating losses, which are subject to an Internal Revenue Service Section 382 limitation (or reduced amount available for deduction as a result of change in control) and expire in 2016 through 2020.

[3] Was generated by NUI and can be carried forward indefinitely to reduce our future tax liability.

Note 13
RELATED PARTY TRANSACTIONS

We previously recognized revenue and had accounts receivable from our affiliate, SouthStar, as detailed on the table below. As a result of our adoption of FIN 46R on January 1, 2004, we consolidated all of SouthStar's accounts with our subsidiaries' accounts and eliminated any intercompany balances between segments. For more discussion of FIN 46R and the impact of its adoption on our consolidated financial statements, see Note 3.

In millions	2004	2003	2002
Recognized revenue	**$—**	$169	$171
Accounts receivable	**$—**	11	—

Note 14
SEGMENT INFORMATION

Our business is organized into three operating segments:

- Distribution operations consists primarily of Atlanta Gas Light, Chattanooga Gas, Elizabethtown Gas, Florida Gas and Virginia Natural Gas.
- Wholesale services consists primarily of Sequent.
- Energy investments consists primarily of SouthStar, Pivotal Jefferson Island, Pivotal Propane, Virginia Gas Company and AGL Networks.

We treat corporate, our fourth segment, as a nonoperating business segment that consists primarily of AGL Resources Inc., AGL Services Company, nonregulated financing and captive insurance subsidiaries and the effect of intercompany eliminations. We eliminated intersegment sales for the years ended December 31, 2004, 2003 and 2002 from our statements of consolidated income.

We evaluate segment performance based primarily on the non-GAAP measure of earnings before interest and taxes (EBIT), which includes the effects of corporate expense allocations. EBIT is a non-GAAP measure that includes operating income, other income, equity in SouthStar's income in 2003 and 2002, donations, minority interest in 2004 and gains on sales of assets. 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.

You should not consider EBIT an alternative to, or a more meaningful indicator of our operating performance than, operating income or net income as determined in accordance with GAAP. In addition, our EBIT may not be comparable to a similarly titled measure of another company. The reconciliations of EBIT to operating income and net income for the years ended December 31, 2004, 2003 and 2002 are presented below:

In millions	2004	2003	2002
Operating revenues	**$1,832**	$983	$877
Operating expenses	**1,500**	741	660
Gain on sale of Caroline Street campus	**—**	16	—
Operating income	**332**	258	217
Other income	**—**	40	30
Minority interest	**(18)**	—	—
EBIT	**314**	298	247
Interest expense	**71**	75	86
Earnings before income taxes	**243**	223	161
Income taxes	**90**	87	58
Income before cumulative effect of change in accounting principle	**153**	136	103
Cumulative effect of change in accounting principle	**—**	(8)	—
Net income	**$ 153**	$128	$103

Summarized income statement, balance sheet and capital expenditure information by segment as of and for the years ended December 31, 2004, 2003 and 2002 are shown in the following tables:

In millions	Distribution Operations	Wholesale Services	Energy Investments	Corporate and Intersegment Eliminations	Consolidated AGL Resources
2004					
Operating revenues from external parties	$ 926	$ 54	$852	$ –	$1,832
Intersegment revenues[1]	185	–	–	(185)	–
Total revenues	1,111	54	852	(185)	1,832
Operating expenses					
Cost of gas	470	1	707	(184)	994
Operation and maintenance	286	27	65	(1)	377
Depreciation and amortization	85	1	4	9	99
Taxes other than income taxes	24	1	1	4	30
Total operating expenses	865	30	777	(172)	1,500
Operating income (loss)	246	24	75	(13)	332
Earnings in equity interests	–	–	2	–	2
Minority interest	–	–	(18)	–	(18)
Other income (loss)	1	–	–	(3)	(2)
EBIT	$ 247	$ 24	$ 59	$ (16)	$ 314
Identifiable assets	$4,386	$696	$630	$ (86)	$5,626
Investment in joint ventures	–	–	235	(221)	14
Total assets	$4,386	$696	$865	$(307)	$5,640
Goodwill	$ 340	$ –	$ 14	$ –	$ 354
Capital expenditures	$ 205	$ 8	$ 40	$ 11	$ 264

In millions	Distribution Operations	Wholesale Services	Energy Investments	Corporate and Intersegment Eliminations	Consolidated AGL Resources
2003					
Operating revenues[1]	$ 936	$ 41	$ 6	$ –	$ 983
Operating expenses					
Cost of gas	337	1	1	–	339
Operation and maintenance	261	20	9	(7)	283
Depreciation and amortization	81	–	1	9	91
Taxes other than income taxes	24	–	–	4	28
Total operating expenses	703	21	11	6	741
Gain (loss) on sale of Caroline Street campus[2]	21	–	–	(5)	16
Operating income (loss)	254	20	(5)	(11)	258
Donation to private foundation	(8)	–	–	–	(8)
Earnings in equity interests	–	–	48	–	48
Other income (loss)	1	–	–	(1)	–
EBIT	$ 247	$ 20	$ 43	$(12)	$ 298
Identifiable assets	$3,325	$460	$ 90	$ 2	$3,877
Investment in joint ventures	–	–	101	–	101
Total assets	$3,325	$460	$191	$ 2	$3,978
Goodwill	$ 177	$ –	$ –	$ –	$ 177
Capital expenditures	$ 126	$ 2	$ 8	$ 22	$ 158

In millions	Distribution Operations	Wholesale Services	Energy Investments	Corporate and Intersegment Eliminations	Consolidated AGL Resources
2002					
Operating revenues[1]	$ 852	$ 23	$ 2	$ –	$ 877
Operating expenses					
Cost of gas	267	—	—	1	268
Operation and maintenance	255	13	8	(2)	274
Depreciation and amortization	82	—	—	7	89
Taxes other than income taxes	25	1	1	2	29
Total operating expenses	629	14	9	8	660
Operating income (loss)	223	9	(7)	(8)	217
Interest income	1	—	—	—	1
Earnings in equity interests	—	—	27	—	27
Other income (loss)	1	—	4	(3)	2
EBIT	$ 225	$ 9	$ 24	$(11)	$ 247
Identifiable assets	$3,150	$364	$107	$ 46	$3,667
Investment in joint ventures	—	—	75	—	75
Total assets	$3,150	$364	$182	$ 46	$3,742
Capital expenditures	$ 128	$ 1	$ 29	$ 29	$ 187

[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
2004	**$4,378**	**$369**	**$4,747**
2003	*3,298*	*353*	*3,651*
2002	1,639	131	1,770

[2] The gain before income taxes of $16 million on the sale of our Caroline Street campus was recorded as operating income (loss) in two of our segments. A gain of $21 million on the sale of the land was recorded in distribution operations, and a write-off of $(5) million on the buildings and their contents was recorded in our corporate segment.

Note 15
QUARTERLY FINANCIAL DATA (UNAUDITED)

Our quarterly financial data for 2004, 2003 and 2002 are summarized below. The variance in our quarterly earnings is the result of the seasonal nature of our primary business.

In millions, except per share amounts	Mar 31	Jun 30	Sep 30	Dec 31
2004				
Operating revenues	**$ 651**	**$ 294**	**$ 262**	**$ 625**
Operating income	**133**	**53**	**46**	**100**
Net income	**66**	**21**	**20**	**46**
Basic earnings per share	**1.02**	**0.34**	**0.31**	**0.64**
Fully diluted earnings per share	**1.00**	**0.33**	**0.31**	**0.64**
2003				
Operating revenues	$ 353	$ 187	$ 166	$ 278
Operating income	101	41	58	58
Income before cumulative effect of change in accounting principle	60	19	22	35
Net income	52	19	22	35
Basic earnings per share before cumulative change in accounting principle	0.99	0.30	0.35	0.54
Basic earnings per share	0.86	0.30	0.35	0.54
Fully diluted earnings per share before cumulative change in accounting principle	0.98	0.29	0.34	0.54
Fully diluted earnings per share	0.85	0.29	0.34	0.54
2002				
Operating revenues	$ 272	$ 161	$ 193	$ 251
Operating income	74	42	38	63
Net income	50	12	10	31
Basic earnings per share	0.90	0.22	0.17	0.55
Fully diluted earnings per share	0.89	0.22	0.17	0.55

Our basic and fully diluted earnings per common share are calculated based on the weighted daily average number of common shares and common share equivalents outstanding during the quarter. Those totals differ from the basic and fully 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.

AGL RESOURCES INC.

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We excluded Jefferson Island Storage & Hub, LLC and NUI Corporation from our assessment of internal control over financial reporting as of December 31, 2004 because they were acquired by us in purchase business combinations during the fourth quarter of 2004. Jefferson Island Storage & Hub, LLC's and NUI Corporation's total assets represents $86 million and $1,352 million, and total revenues represents $11 million and $86 million, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2004.

Based on our evaluation under the framework in *Internal Control—Integrated Framework* issued by COSO, our management concluded that our internal control over financial reporting was effective as of December 31, 2004. Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report, which insofar as it relates to the effectiveness of SouthStar Energy Services LLC is based solely upon the report of other auditors and is included herein.

Paula Rosput Reynolds
Chairman, President and Chief Executive Officer

Richard T. O'Brien
Executive Vice President and Chief Financial Officer

February 14, 2005

SOUTHSTAR ENERGY SERVICES LLC

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and in accordance with, Public Company Accounting Oversight Board's Auditing Standard No. 2, *An Audit of Internal Control Over Financial Reporting Performed in Conjunction With an Audit of Financial Statements.* Based on our evaluation under the framework in *Internal Control—Integrated Framework*, our management concluded that our internal control over financial reporting was effective as of December 31, 2004.

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Michael A. Braswell
President, SouthStar Energy Services LLC

Michael A. Degnan
Director, Finance & Accounting, SouthStar Energy Services LLC

February 2, 2005

TO THE BOARD OF DIRECTORS AND SHAREHOLDERS OF AGL RESOURCES INC.:

We have completed an integrated audit of AGL Resources Inc.'s 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and an audit of its 2003 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits and the reports of other auditors, are presented below.

Consolidated financial statements

In our opinion, based on our audits and the report of other auditors, the accompanying consolidated balance sheets and statements of income, common shareholders' equity, and cash flows present fairly, in all material respects, the financial position of AGL Resources Inc. and its subsidiaries at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. 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 did not audit the financial statements of SouthStar Energy Services LLC, a joint venture in which a subsidiary of the Company has a non-controlling 70% financial interest, which statements reflect total assets of $243 million and total revenues of $827 million as of and for the year ended December 31, 2004. The Company's equity investment in SouthStar Energy Services LLC was $71 million and equity in earnings was $46 million as of and for the year ended December 31, 2003. 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 audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements 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 audits and the report of other auditors provide a reasonable basis for our opinion.

As discussed in Note 3 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 3 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*. As discussed in Note 3 to the consolidated financial statements, effective January 1, 2004, AGL Resources Inc. and subsidiaries adopted Financial Accounting Standards Board (FASB) Interpretation No. 46-R, "Consolidation of Variable Interest Entities".

Internal control over financial reporting

Also, in our opinion, based on our audit and the report of other auditors, management's assessment, included in Management's Report on Internal Control Over Financial Reporting related to AGL Resources Inc. appearing on page 107 of AGL Resources, Inc Annual Report to Shareholders, that the Company maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, based on our audit and the report of other auditors, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control—Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We did not examine the effectiveness of internal control of SouthStar Energy Services LLC as of December 31, 2004. The effectiveness of SouthStar Energy Services LLC's internal control over financial reporting was audited by other auditors whose report has been furnished to us, and our opinions expressed herein, insofar as they relate to the effectiveness of SouthStar Energy Services LLC's internal control over financial reporting are based solely on the report of the other auditors. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit and the report of the other auditors provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As described in Management's Report on Internal Control over Financial Reporting, management has excluded Jefferson Island Storage & Hub LLC and NUI Corporation from its assessment of internal control over financial reporting as of December 31, 2004 because they were acquired by the Company in purchase business combinations during 2004. We have also excluded Jefferson Island Storage & Hub LLC and NUI Corporation from our audit of internal control over financial reporting. Jefferson Island Storage & Hub LLC and NUI Corporation are wholly owned subsidiaries whose total assets represent $86 million and $1,352 million and total revenues represent $11 million and $86 million, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2004.

PricewaterhouseCoopers LLP

Atlanta, Ga.
February 14, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

THE EXECUTIVE COMMITTEE AND MEMBERS OF SOUTHSTAR ENERGY SERVICES LLC

We have audited management's assessment, included in the accompanying Report of Management on Internal Control Over Financial Reporting, that SouthStar Energy Services LLC ("SouthStar") maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO criteria"). SouthStar's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that SouthStar maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, SouthStar maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the balance sheets of SouthStar as of December 31, 2004 and 2003, 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, 2004 of SouthStar and our report dated February 4, 2005 expressed an unqualified opinion thereon.

Ernst & Young LLP

Atlanta, Georgia
February 4, 2005

THE EXECUTIVE COMMITTEE AND MEMBERS SOUTHSTAR ENERGY SERVICES LLC

We have audited the balance sheets of SouthStar Energy Services LLC (the Company) as of December 31, 2004 and 2003, 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, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of SouthStar Energy Services LLC at December 31, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004 in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of SouthStar Energy Services LLC's internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 4, 2005 expressed an unqualified opinion thereon.

Ernst & Young LLP

Atlanta, Georgia
February 4, 2005

TO THE SHAREHOLDERS AND BOARD OF DIRECTORS OF AGL RESOURCES INC.:

We have audited the accompanying consolidated statements of income, shareholders' equity, and cash flows for the year ended December 31, 2002 of AGL Resources Inc. and subsidiaries (the "Company"). These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether 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, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the results of operations and cash flows of AGL Resources Inc. and subsidiaries for the year ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
January 27, 2003

CORPORATE HEADQUARTERS
AGL Resources Inc., Ten Peachtree Place, N.E., Atlanta, GA 30309; 404-584-4000; website: aglresources.com

TRANSFER AGENT AND REGISTRAR
EquiServe serves as our transfer agent and registrar and can help with a variety of stock-related matters, including name and address changes; transfer of stock ownership; lost certificates; and Form 1099s.

Inquiries may be directed to: AGL Resources Shareholder Services, c/o EquiServe Trust Company, N.A., P.O. Box 43010, Providence, RI 02190-3010. Toll-free: 800-633-4236; website: equiserve.com

AVAILABLE INFORMATION
A copy of this Annual Report, as well as our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, other reports that we file with or furnish to the Securities and Exchange Commission (SEC) and our recent news releases are available free of charge on the internet at our website aglresources.com as soon as reasonably practicable after we electronically file such reports with, or furnish such reports to, the SEC. These reports and news releases are available on our website or through a toll-free interactive shareholder information line at 877-ATG-NYSE (877-284-6973). 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.

Our Annual Report on Form 10-K includes the certifications of our chief executive officer and chief financial officer required by Sections 302 and 906 of the Sarbanes-Oxley Act of 2002. Additionally, we filed with the New York Stock Exchange the certification by our chief executive officer that she is not aware of any violation of New York Stock Exchange corporate governance listing standards.

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 development, environmental and corporate responsibility, executive, finance and risk management and nominating and corporate governance committees, are available on our website.

The above information will also be furnished free of charge upon written request to our Investor Relations department at: AGL Resources, Investor Relations, Dept. 1071, Ten Peachtree Place, N.E., Atlanta, GA 30309; 404-584-4414

INSTITUTIONAL INVESTOR INQUIRIES
Institutional investors and securities analysts should direct inquiries to: Brian Little, Director, Investor Relations, c/o AGL Resources, Investor Relations, Dept. 1071, Ten Peachtree Place, N.E., Atlanta, GA 30309; 404-584-4414; blittle@aglresources.com

ANNUAL MEETING
The 2005 annual meeting of shareholders will be held Wednesday, April 27, 2005, at Ten Peachtree Place, N.E., Atlanta, Georgia 30309.

RESOURCESDIRECT™
New investors may make an initial investment, and shareholders of record may acquire additional shares of our common stock, through ResourcesDIRECT™ without paying brokerage fees or service charges. Initial cash investments, quarterly cash dividends and/or optional cash purchases may be invested through the plan, subject to certain requirements. To obtain a copy of the plan prospectus and enrollment materials, contact our transfer agent, call our toll-free interactive shareholder line at 877-ATG-NYSE (877-284-6973) or visit our website at aglresources.com.

STOCK PRICE AND DIVIDEND INFORMATION
Our common stock is listed on the New York Stock Exchange under the symbol ATG. At January 20, 2005, there were approximately 11,135 record holders of our common stock. Quarterly information concerning our high and low prices and cash dividends that we paid in 2004 and 2003 is as follows:

2004

	Sales Price of Common Stock		Cash Dividend
Quarter ended	High	Low	per Common Share
March 31, 2004	**$30.63**	**$27.87**	**$0.28**
June 30, 2004	**29.41**	**26.50**	**$0.29**
September 30, 2004	**31.27**	**28.60**	**$0.29**
December 31, 2004	**33.65**	**30.11**	**$0.29**

2003

	Sales Price of Common Stock		Cash Dividend
Quarter ended	High	Low	per Common Share
March 31, 2003	$25.41	$21.90	$0.27
June 30, 2003	26.98	23.30	$0.28
September 30, 2003	28.49	25.35	$0.28
December 31, 2003	29.35	27.24	$0.28

We pay dividends four times a year: March 1, June 1, September 1 and December 1. We have paid 229 consecutive quarterly dividends beginning in 1948. Dividends are declared at the discretion of our Board of Directors, and future dividends will depend on our future earnings, cash flow, financial requirements and other factors. In February 2005, we increased the quarterly dividend to $0.31 per common share.

PREFERRED SECURITIES
Our preferred securities are listed and traded on the New York Stock Exchange under the ticker symbol ATG_P.

DIRECTORS AND OFFICERS

Board of Directors

pictured in left column

Wyck A. Knox, Jr.[4*,5,6]
Partner
Kilpatrick Stockton LLP
Augusta, GA
Director since 1998

Michael J. Durham[1*,4]
Founder, President and
Chief Executive Officer
Cognizant Associates, Inc.
Dallas, TX
Director since 2003

Henry C. Wolf[1,4]
Vice Chairman and
Chief Financial Officer
Norfolk Southern Corporation
Norfolk, VA
Director since 2004

Thomas D. Bell, Jr.[2,7]
Vice Chairman, President and
Chief Executive Officer
Cousins Properties Incorporated
Atlanta, GA
Director since 2004

Bettina M. Whyte[2,3,7]
Managing Director
AlixPartners, LLC
New York, NY
Director since 2004

James A. Rubright[2,3,5,6*]
Chairman and
Chief Executive Officer
Rock-Tenn Company
Norcross, GA
Director since 2001

pictured in right column

Felker W. Ward, Jr.[5,6,7*]
Chairman
Pinnacle Investment Advisors, Inc.
Union City, GA
Director since 1988

Charles R. Crisp[3*,6,7]
Former President, Chief Executive
Officer and Director of Coral Energy,
a subsidiary of Shell Oil Company
Houston, TX
Director since 2003

Paula Rosput Reynolds[3,4,5,6]
Chairman, President and
Chief Executive Officer
AGL Resources Inc.
Atlanta, GA
Director since 2000

Dennis M. Love[1,7]
President and
Chief Executive Officer
Printpack Inc.
Atlanta, GA
Director since 1999

D. Raymond Riddle[1,2,5*]
Retired Chairman and
Chief Executive Officer
National Service Industries, Inc.
Atlanta, GA
Director since 1978

Arthur E. Johnson[2*,4]
Senior Vice President
Lockheed Martin Corporation
Bethesda, MD
Director since 2002

* Committee chair

[1] Audit, [2] Compensation and Management Development, [3] Corporate Development, [4] Environmental and Corporate Responsibility, [5] Executive, [6] Finance and Risk Management, [7] Nominating and Corporate Governance.

All members of the Audit, Compensation and Management Development, and Nominating and Corporate Governance Committees are "independent" as defined under applicable rules and regulations.

Executive Officers

Paula Rosput Reynolds, Chairman, President and Chief Executive Officer

Richard T. O'Brien, Executive Vice President and Chief Financial Officer

Kevin P. Madden, Executive Vice President of Distribution and Pipeline Operations

Paul R. Shlanta, Senior Vice President, General Counsel
and Chief Corporate Compliance Officer

Melanie M. Platt, Senior Vice President, Human Resources

Design, copywriting and production: Thinkhouse Creative. Principal photography: Studio Burns. Printing: OW Acme Printing.

AGL Resources

Ten Peachtree Place, N.E., Atlanta, Georgia 30309, aglresources.com