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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2007

OR

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

For the transition period from to

Commission File Number 1-14174

AGL RESOURCES INC.

(Exact name of registrant as specified in its charter)

Georgia	**58-2210952**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
Ten Peachtree Place NE, **Atlanta, Georgia 30309**	**404-584-4000**
(Address and zip code of principal executive offices)	(Registrant's telephone number, including area code)

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

Title of Class	Name of each exchange on which registered
Common Stock, $5 Par Value	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 under the Securities Act.
Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Act.
Yes ☐ No ☑

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer or a non-accelerated filer.
Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐

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

The aggregate market value of the registrant's voting and non-voting common equity held by non-affiliates of the registrant, computed by reference to the price at which the registrant's common stock was last sold as of the last business day of the registrant's most recently completed second fiscal quarter, was $3,148,134,781

The number of shares of the registrant's common stock outstanding as of January 31, 2008 was 76,439,305.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the Proxy Statement for the 2008 Annual Meeting of Shareholders ("Proxy Statement") to be held April 30, 2008, are incorporated by reference in Part III.

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GLOSSARY OF KEY TERMS

Atlanta Gas Light	Atlanta Gas Light Company
AGL Capital	AGL Capital Corporation
AGL Networks	AGL Networks, LLC
AGSC	AGL Services Company
AIP	Annual Incentive Plan
Bcf	Billion cubic feet
Chattanooga Gas	Chattanooga Gas Company
Compass Energy	Compass Energy Services, Inc.
Credit Facility	Credit agreement supporting our commercial paper program
Deregulation Act	1997 Natural Gas Competition and Deregulation Act
Dominion Ohio	Dominion East of Ohio, a Cleveland, Ohio based natural gas company; a subsidiary of Dominion Resources, Inc.
EBIT	Earnings before interest and taxes, a non-GAAP measure that includes operating income, other income, equity in SouthStar's income, minority interest in SouthStar's earnings, donations and gain on sales of assets and excludes interest and income tax expense; as an indicator of our operating performance, EBIT should not be considered an alternative to, or more meaningful than, operating income or net income as determined in accordance with GAAP
EITF	Emerging Issues Task Force
Energy Act	Energy Policy Act of 2005
ERC	Environmental remediation costs
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings
Florida Commission	Florida Public Service Commission
GAAP	Accounting principles generally accepted in the United States of America
Georgia Commission	Georgia Public Service Commission
Golden Triangle Storage	Golden Triangle Storage, Inc.
Heating Season	The period from November to March when natural gas usage and operating revenues are generally higher because more customers are connected to our distribution systems when weather is colder
Jefferson Island	Jefferson Island Storage & Hub, LLC
LIBOR	London interbank offered rate
LNG	Liquefied natural gas
LOCOM	Lower of weighted average cost or current market price
Louisiana DNR	Louisiana Department of Natural Resources
Maryland Commission	Maryland Public Service Commission
Marketers	Marketers selling retail natural gas in Georgia and certificated by the Georgia Commission
Medium-term notes	Notes issued by Atlanta Gas Light with scheduled maturities between 2012 and 2027 bearing interest rates ranging from 6.6% to 9.1%
MGP	Manufactured gas plant
Moody's	Moody's Investors Service
New Jersey Commission	New Jersey Board of Public Utilities
NUI	NUI Corporation
NYMEX	New York Mercantile Exchange, Inc.
OCI	Other comprehensive income
Operating margin	A measure of income, calculated as revenues minus cost of gas, that excludes operation and maintenance expense, depreciation and amortization, taxes other than income taxes, and the gain or loss on the sale of our assets; these items are included in our calculation of operating income as reflected in our statements of consolidated income.
Piedmont	Piedmont Natural Gas
Pivotal Propane	Pivotal Propane of Virginia, Inc.
Pivotal Utility	Pivotal Utility Holdings, Inc., doing business as Elizabethtown Gas, Elkton Gas and Florida City Gas
PGA	Purchased gas adjustment
PRP	Pipeline replacement program for Atlanta Gas Light
S&P	Standard & Poor's Ratings Services
Saltville	Saltville Gas Storage Company
SEC	Securities and Exchange Commission
Sequent	Sequent Energy Management, L.P.
SFAS	Statement of Financial Accounting Standards
SNG	Southern Natural Gas Company
SouthStar	SouthStar Energy Services LLC
Tennessee Commission	Tennessee Regulatory Authority
VaR	Value at risk 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
Virginia Natural Gas	Virginia Natural Gas, Inc.
Virginia Commission	Virginia State Corporation Commission
WACOG	Weighted average cost of goods
WNA	Weather normalization adjustment

REFERENCED ACCOUNTING STANDARDS

APB 25	APB Opinion No. 25, "Accounting for Stock Issued to Employees"
EITF 98-10	EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities"
EITF 99-02	EITF Issue No. 99-02, "Accounting for Weather Derivatives"
EITF 00-11	EITF Issue No. 00-11, "Lessor's Evaluation of Whether Leases of Certain Integral Equipment Meet the Ownership Transfer Requirements of FASB Statement No. 13, *Accounting for Leases*, for Leases of Real Estate"
EITF 02-03	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'"
FIN 39	FASB Interpretation No. (FIN) 39 "Offsetting of Amounts Related to Certain Contracts"
FSP FIN 39-1	FASB Staff Position 39-1 "Amendment of FIN 39"
FIN 46 & FIN 46R	FIN 46, "Consolidation of Variable Interest Entities"
FIN 47	FIN 47, "Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143"
FIN 48	FIN 48, "Accounting for Uncertainty in Income Taxes, an interpretation of SFAS Statement No. 109"
SFAS 5	SFAS No. 5, "Accounting for Contingencies"
SFAS 13	SFAS No. 13, "Accounting for Leases"
SFAS 66	SFAS No. 66, "Accounting for Sales of Real Estate"
SFAS 71	SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation"
SFAS 87	SFAS No. 87, "Employers' Accounting for Pensions"
SFAS 106	SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions"
SFAS 109	SFAS No. 109, "Accounting for Income Taxes"
SFAS 123 & SFAS 123R	SFAS No. 123, "Accounting for Stock-Based Compensation"
SFAS 133	SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities"
SFAS 141	SFAS No. 141, "Business Combinations"
SFAS 142	SFAS No. 142, "Goodwill and Other Intangible Assets"
SFAS 148	SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure"
SFAS 149	SFAS No. 149, "Amendment of SFAS 133 on Derivative Instruments and Hedging Activities"
SFAS 157	SFAS No. 157, "Fair Value Measurements"
SFAS 158	SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans"
SFAS 159	SFAS No. 159, "The Fair Value Option for Financial Assets and Liabilities"
SFAS 160	SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements"

PART I

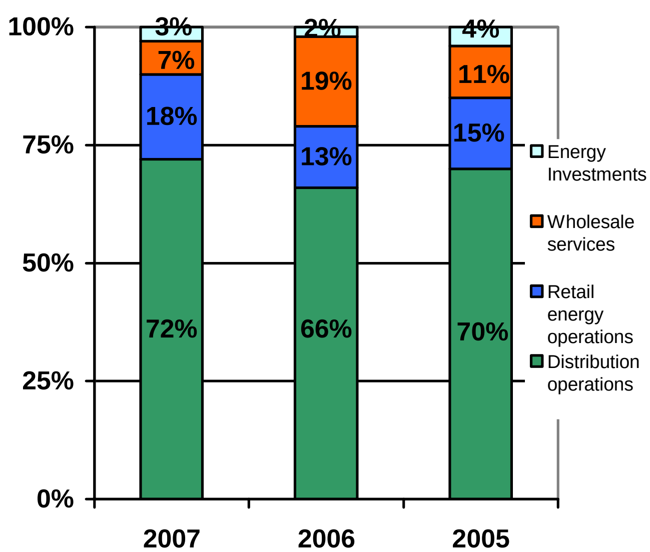
ITEM 1. BUSINESS

Nature of Our Business

Unless the context requires otherwise, references to “we,” “us,” “our,” the “company” and “AGL Resources” are intended to mean consolidated AGL Resources Inc. and its subsidiaries.

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. We generate nearly all our operating revenues through the sale, distribution, transportation and storage of natural gas. Our six utilities serve more than 2.2 million end-use customers, making us the largest distributor of natural gas in the southeastern and mid-Atlantic regions of the United States based on customer count. We are involved in several related and complementary businesses, including retail natural gas marketing to end-use customers primarily in Georgia; natural gas asset management and related logistics activities for each of our utilities as well as for nonaffiliated companies; natural gas storage arbitrage and related activities; and the development and operation of high-deliverability natural gas storage assets. We also own and operate a small telecommunications business that constructs and operates conduit and fiber infrastructure within select metropolitan areas.

We manage these businesses through four operating segments and a nonoperating corporate segment. Each operating segment’s percentage contribution to the total operating EBIT for the last three years is indicated in the following chart.



Over the last three years, on average, we have derived approximately 85% of our EBIT from our regulated natural gas distribution business and the sale of natural gas to end-use customers primarily in Georgia through SouthStar. This statistic is significant because it represents the portion of our earnings that directly results from the underlying business of supplying natural gas to retail customers. SouthStar, which is subject to a different regulatory framework from our utilities, is an integral part of the retail framework for providing natural gas service to end-use customers in Georgia.

We derived the remaining percentage (15% or less for the last three years) of our EBIT principally from businesses that are complementary to our natural gas distribution business. We engage in natural gas asset management and the operation of high-deliverability natural gas underground storage as ancillary activities to our utility franchises. These businesses allow us to be opportunistic in capturing incremental value at the wholesale level and provide us with deepened business insight about natural gas market dynamics. 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.

Operating revenues, operating margin, operating expenses and EBIT for each of our segments are presented in the following table for 2007, 2006 and 2005.

In millions	Operating revenues	Operating margin (1)	Operating expenses	EBIT (1)
2007				
Distribution operations	$1,665	$820	$485	$338
Retail energy operations	892	188	75	83
Wholesale services	83	77	43	34
Energy investments	42	40	25	15
Corporate (2)	(188)	-	8	(7)
Consolidated	$2,494	$1,125	$636	$463
2006				
Distribution operations	$1,624	$807	$499	$310
Retail energy operations	930	156	68	63
Wholesale services	182	139	49	90
Energy investments	41	36	26	10
Corporate (2)	(156)	1	9	(9)
Consolidated	$2,621	$1,139	$651	$464
2005				
Distribution operations	$1,753	$814	$518	$299
Retail energy operations	996	146	61	63
Wholesale services	95	92	42	49
Energy investments	56	40	23	19
Corporate (2)	(182)	-	6	(11)
Consolidated	$2,718	$1,092	$650	$419

(1) These are non-GAAP measurements. A reconciliation of operating margin and EBIT to our operating income and net income is contained in “Results of Operations” herein.
(2) Includes intercompany eliminations

Distribution Operations

The distribution operations segment is the largest component of our business and includes six natural gas local distribution utilities. These utilities construct, manage and maintain intrastate natural gas pipelines and distribution facilities and include:

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

Regulatory Environment

Each utility operates subject to regulations of the state regulatory agency in its service territories with respect to rates charged to our customers and various 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 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 generally consists of the original cost of utility plant in service, working capital, inventories and certain other assets; less accumulated depreciation on utility plant in service and net deferred income tax liabilities, and may include certain other additions or deductions.

Atlanta Gas Light does not sell natural gas directly to its customers and does not need or utilize a PGA. All of our other utilities are authorized to use a PGA mechanism that allows them to adjust their rates to reflect changes in the wholesale cost of natural gas and to ensure they recover 100% of the costs incurred in purchasing gas for their customers. We continuously monitor the performance of our utilities to determine whether rates need to be further adjusted through the regulatory process. We have fixed rate settlements in three of our six jurisdictions in Georgia, New Jersey and Virginia.

Atlanta Gas Light's natural gas market was deregulated in 1997 with the Deregulation Act. Prior to this act, Atlanta Gas Light was the supplier and seller of natural gas to its customers. Today, Marketers sell natural gas to end-use customers in Georgia and handle customer billing functions. The Marketers file their rates monthly with the Georgia Commission. 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
- reading meters and maintaining underlying customer premise information for Marketers

Atlanta Gas Light recognizes revenue under a straight-fixed-variable rate design whereby Atlanta Gas Light charges rates to its customers based primarily on monthly fixed charges. The Marketers bill these charges directly to their customers. This mechanism minimizes the seasonality of revenues since the monthly fixed charge is not volumetric or 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 are connected in periods of colder weather than in periods of warmer weather.

Regulatory Agreements In September 2007, the Georgia Commission approved our request to obtain an undivided interest in pipelines connecting our Georgia service territory to liquefied natural gas facilities at Elba Island, Georgia. We along with SNG have undertaken this pipeline project in an effort to diversify our sources of natural gas. We currently receive the majority of our natural gas supply from a production region in and around the Gulf of Mexico and generally, demand for this natural gas is growing faster than supply. This project is contingent upon FERC approval and therefore SNG and ourselves jointly filed an application with the FERC in October 2007. We anticipate that we will receive FERC approval in 2008. Construction is expected to begin in 2008 and to be completed in 2009.

In December 2007, the Florida Commission approved our request to include the amortization of certain components of the purchase price we paid for Florida City Gas in our calculation of return on equity. The costs will not be amortized for financial reporting purposes in accordance with GAAP but will be amortized over a period of 5 to 30 years for our regulatory reporting to the Florida Commission in connection with the Florida Commission's review of Florida City Gas' return on equity. Additionally and under the same order, the Florida Commission approved a five-year base rate stay-out beginning October 2007, whereby base rates will not be increased, except for certain unforeseen acts beyond our control. The five-year stay-out provision does not preclude the Florida Commission from initiating over earning or other proceedings.

A November 2004 agreement between Elizabethtown Gas and the New Jersey Commission approved our acquisition of NUI Corporation. This agreement included, among other things, a base rate freeze for Elizabethtown Gas for the five-year period from November 2004 to October 2009. Beginning with the annual measurement period in December 2007, 75% of Elizabethtown Gas' earnings in excess of an 11% return on equity would be shared with rate payers in the fourth and fifth years of the base rate stay-out period.

Weather Normalization Certain of our non-Georgia jurisdictions have various regulatory mechanisms that allow us to recover our costs in the event of unusual weather, but they are not direct offsets to the potential impacts of weather and customer consumption on earnings. The tariffs of Elizabethtown Gas, Virginia Natural Gas, and Chattanooga Gas contain WNA provisions that are designed to help stabilize operating results by increasing base rate amounts charged to customers when weather is warmer than normal and decreasing amounts charged when weather is colder than normal. The WNA is most effective in a reasonable temperature range relative to normal weather using historical averages. The following table provides certain regulatory information for our largest utilities.

	Atlanta Gas Light	**Elizabethtown Gas**	**Virginia Natural Gas**	**Florida City Gas**	**Chattanooga Gas**
State regulator	Georgia Commission	New Jersey Commission	Virginia Commission	Florida Commission	Tennessee Commission
Current rates effective until	May 2010	Jan. 2010	Aug. 2011	N/A	Jan. 2011
Authorized return on rate base (1)	8.53%	7.95%	9.24%	7.36%	7.89%
Estimated 2007 return on rate base (2) (4)	8.59%	8.46%	7.90%	6.09%	7.53%
Authorized return on equity	10.9%	10.0%	10.9%	11.25%	10.2%
Estimated 2007 return on equity (2) (4)	11.03%	10.32%	8.96%	7.04%	9.40%
Authorized rate base % of equity (3)	47.9%	53.0%	52.4%	36.8%	44.8%
Rate base included in 2007 return on equity (in millions) (3) (4)	$1,271	$441	$350	$146	$100

(1) The authorized return on rate base, return on equity, and percentage of equity reflected above were those authorized as of December 31, 2007.
(2) Estimate based on principles consistent with utility ratemaking in each jurisdiction. Returns are not necessarily consistent with GAAP returns.
(3) Estimated based on 13-month average.
(4) Florida City Gas includes the impacts of the acquisition adjustment, as approved by the Florida Commission in December 2007, in its rate base, return on rate base and return on equity calculations.

Customer Demand All of our utilities face competition from other energy products. Our principal competition arises from electric utilities and oil and propane providers serving the residential and 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 prices for competing sources of energy as compared to natural gas and the desirability of natural gas heating versus alternative heating sources.

Competition for space heating and general household and small commercial energy needs generally occurs at the initial installation phase when the customer or builder makes decisions as to which types of equipment to install. Customers generally continue to use the chosen energy source for the life of the equipment. Customer demand for natural gas 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
- new housing starts

In some of our service areas, net growth continues to be slowed due to the number of customers who leave our systems because of higher natural gas prices, slower economic growth in some of our service areas and competition from alternative fuel sources, including incentives offered by the local electric utilities to switch to electric alternatives.

Through our targeted marketing and customer retention programs, we have improved the retention of our existing customers. Additionally, these activities have enabled us to obtain new customers, although at a lower rate than expected, due in part to downturns in the general economy and the housing and related mortgage markets. We expect these conditions to continue for an extended period of time and that such conditions could impact our net customer growth. Consequently, we will focus even more on our marketing and customer retention efforts.

These efforts include working to add residential customers, 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 converting to alternative fuels.

Collective Bargaining Agreements In 2007, collective bargaining agreements, representing 55 employees at Atlanta Gas Light, Chattanooga Gas and Elizabethtown Gas were terminated as a result of the decertification of the respective unions. Accordingly, these 55 employees are no longer represented by a bargaining agreement and now fall under our standard human resources pay and benefit plans and policies. In January 2008, approximately 55 Florida City Gas employees filed for decertification of their union. The vote is expected to occur in February 2008.

The following table provides information about the collective bargaining agreements to which our natural gas local distribution utilities are parties. Additionally, we believe that our relations with our employees are good.

	Affiliated subsidiary	**Approximate # of employees**	**Date of contract expiration**
Teamsters (Local Nos. 769 and 385)	Florida City Gas	55	March 2008
Utility Workers Union of America (Local No. 424)	Elizabethtown Gas	160	November 2009
International Brotherhood of Electrical Workers (Local No. 50)	Virginia Natural Gas	140	May 2010
	Total	355	

Retail Energy Operations

Our retail energy operations segment consists of SouthStar, a joint venture owned 70% by our subsidiary, Georgia Natural Gas Company, and 30% by Piedmont. SouthStar markets natural gas and related services under the trade name Georgia Natural Gas to retail customers on an unregulated basis, primarily in Georgia as well as to commercial and industrial customers, principally in Florida, Tennessee, North Carolina, South Carolina and Alabama. Based on its market share, SouthStar is the largest Marketer of natural gas in Georgia, with average customers in excess of 530,000 over the last three years.

SouthStar is governed by an executive committee, which is comprised of six members, three representatives from AGL Resources and three from Piedmont. Under a joint venture agreement, all significant management decisions require the unanimous approval of the SouthStar executive committee; accordingly, our 70% financial interest is considered to be noncontrolling. Although our ownership interest in the SouthStar partnership is 70%, under an amended and restated joint venture agreement (Restated Agreement) executed in March 2004, SouthStar's earnings are allocated 75% to us and 25% to Piedmont except for earnings related to customers in Ohio and Florida, which are allocated 70% to us and 30% to Piedmont. We record the earnings allocated to Piedmont as a minority interest in our consolidated statements of income, and we record Piedmont's portion of SouthStar's capital as a minority interest in our consolidated balance sheets.

The Restated Agreement includes a provision granting us three opportunities to exercise an option to purchase Piedmont's ownership interest in SouthStar. Our first option exercise opportunity was on November 1, 2007, which we did not exercise and we have two remaining opportunities on November 1, 2008 and 2009, to purchase certain portions of Piedmont's interest, both of which would be effective on January 1 of the following year. If we were to exercise our option on November 1, 2008, Piedmont, at its discretion, could require us to purchase their entire ownership interest. The purchase price would be based on the fair market value of SouthStar.

In August 2006, SouthStar was awarded the right to supply a total of approximately 10 Bcf of natural gas to customers of Dominion Ohio through August 2008 (approximately 5 Bcf/year). As part of this agreement, SouthStar manages the supply, transportation and storage of natural gas on behalf of Dominion Ohio. The Dominion Ohio agreement did not materially affect our results of operations in 2007. SouthStar's entrance into the Ohio market is part of its continued growth strategy.

SouthStar's operations also are sensitive to customer consumption patterns similar to those affecting our utility operations. SouthStar uses a variety of hedging strategies, such as futures, options, swaps, weather derivative instruments and other risk management tools, to mitigate the potential effect of these issues on its operations.

Competition SouthStar competes with other energy marketers, including Marketers in Georgia, to provide natural gas and related services to customers in Georgia and the Southeast. In addition, similar to our distribution operations, SouthStar faces competition based on customer preferences for natural gas compared to other energy products and the comparative prices of those products. SouthStar's principal competitors for other non-natural gas energy products relates to electric utilities and the potential displacement or replacement of natural gas appliances with electric appliances. This competition with other energy products has been exacerbated by price volatility in the wholesale natural gas commodity market and related significant increases in the cost of natural gas billed to SouthStar's customers, especially during portions of 2005 and 2006.

Operating margin SouthStar generates operating margin primarily in three ways. The first is through the sale of natural gas to retail customers in the residential, commercial and industrial sectors, primarily in Georgia where SouthStar captures a spread between wholesale and retail natural gas prices. The second way is through the collection of monthly service fees and customer late payment fees.

SouthStar evaluates the combination of these two retail price components to ensure such pricing is structured to cover related retail customer costs, such as bad debt expense, customer service and billing, and lost and unaccounted-for gas, and to provide a reasonable profit, as well as being competitive to attract new customers and maintain market share. SouthStar's operating margin is impacted by seasonal weather, natural gas prices, customer growth and SouthStar's related market share in Georgia, which has historically been approximately 35%, based on number of customers. SouthStar employs strategies to attract and retain a higher credit-quality customer base. These strategies result not only in higher operating margin, as these customers tend to utilize higher volumes of natural gas, but also help to mitigate bad debt expense due to the higher credit-quality of customers.

The third way SouthStar generates operating margin is through its commercial operations of optimizing storage and transportation assets and effectively managing commodity risk, which enables SouthStar to maintain competitive retail prices and operating margin. SouthStar is allocated storage and pipeline capacity that is used to supply natural gas to its customers in Georgia. Through hedging transactions, SouthStar manages exposures arising from changing commodity prices using natural gas storage transactions to capture operating margin from natural gas pricing differences that occur over time. SouthStar's risk management policies allow the use of derivative instruments for hedging and risk management purposes but prohibit the use of derivative instruments for speculative purposes.

SouthStar accounts for its natural gas inventories at the lower of weighted average cost or current market price. SouthStar evaluates the weighted average cost of its natural gas inventories against market prices and determines whether any declines in market prices below the weighted average cost are other than temporary. For declines considered to be other than temporary, SouthStar records adjustments to cost of gas (LOCOM adjustments) in our consolidated statement of income to reduce the weighted average cost of the natural gas inventory to the current market price. SouthStar recorded a LOCOM adjustment of $6 million in 2006. SouthStar did not record a LOCOM adjustment in 2007 or 2005.

SouthStar also enters into weather derivative instruments in order to preserve operating margin profits in the event of warmer-than-normal weather in the winter months. These contracts are accounted for using the intrinsic value method under EITF 99-02*.* The weather derivative contracts contain settlement provisions based on cumulative heating degree days for the covered periods. SouthStar entered into weather derivatives (swaps and options) for both the 2006 to 2007, and 2007 to 2008 heating seasons. SouthStar recorded net gains on these weather derivatives of approximately $4 million in 2007 and $5 million in 2006. These gains were largely offset by corresponding losses of operating margin due to the warm weather the hedges were designed to protect against. SouthStar had no weather derivatives in 2005 and therefore no gains or losses were recorded during 2005.

Wholesale Services

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

In addition, Sequent takes advantage of arbitrage opportunities within the natural gas supply, storage and transportation markets to generate earnings, and its profitability is correlated to volatility in these markets. Natural gas market volatility can result from a number of factors, such as weather fluctuations or the change in supply of, or demand for, natural gas in different regions of the country. Sequent seeks to capture value from the price disparity among geographic locations and various time horizons created by this volatility. In doing so, Sequent also seeks to mitigate the risks associated with this volatility and protect its operating margin through a variety of risk management and hedging activities.

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 purchases transportation and storage capacity to meet its delivery requirements and customer obligations in the marketplace and its customers benefit from its logistics expertise and ability to deliver natural gas at prices that are advantageous relative to other alternatives. Sequent has entered into agreements that have facilitated the expansion of its operations into the western United States and Canada and plans to pursue additional opportunities in these regions during 2008. Sequent continues to work on projects and transactions to extend its operating territory and is entering into agreements of longer duration, as well as evaluating opportunities to expand its business focus and models including its commercial and industrial customer base through acquisitions and organic growth.

Competition Sequent competes for asset management business with other energy wholesalers, often through a competitive bidding process. There has been significant consolidation of energy wholesale operations, particularly among major natural 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 asset management transactions and the related operating margin available in this portion of Sequent's business.

Asset Management Transactions Sequent's asset management customers include affiliated utilities, nonaffiliated utilities, municipal utilities, power generators and large industrial customers. These customers, due to seasonal demand or levels of activity, may have contracts for transportation and storage capacity, which may exceed their actual requirements. Sequent enters into structured agreements with these customers, whereby Sequent, on behalf of the customer, optimizes the transportation and storage capacity during periods when customers do not use it for their own needs. Sequent may capture incremental operating margin through optimization, and either share margins with the customers or pay them a fixed amount.

The following table provides additional information on Sequent's asset management agreements with its affiliated utilities.

In millions	Expiration date	Timing of payment	Type of fee structure	% Shared or annual fee	Profit sharing / fees payments 2007	2006	2005
Elkton Gas	Mar 2008	Monthly	Fixed-fee	(A)	$-	$-	$-
Chattanooga Gas	Mar 2008	Annually	Profit -sharing	50%	2	4	2
Elizabethtown Gas	Mar 2008	Monthly	Fixed -fee	$4	6	4	-
Florida City Gas	Mar 2008	Annually	Profit -sharing	50%	1	-	-
Virginia Natural Gas	Mar 2009	Annually	Profit -sharing	(B)	7	2	5
Atlanta Gas Light	Mar 2012	Quarterly	Profit -sharing	60%	9	6	4
Total					$25	$16	$11

(A) Annual fixed fee is approximately $11,000.
(B) Profit sharing is based on a tiered sharing structure.

In October 2007, the Georgia Commission extended the asset management agreement between Sequent and Atlanta Gas Light to March 2012. Under the terms of the extended agreement, the sharing percentages are unchanged; however the agreement now includes guaranteed minimum annual payments to be made by Sequent of approximately $4 million. The contract year under the extended agreement will be April 1 to March 31 with Sequent making quarterly sharing payments. Sequent is actively negotiating the renewal of its remaining affiliate asset management agreements scheduled to expire in 2008, which require regulatory approval.

Transportation Transactions Sequent contracts for natural gas transportation capacity and participates in transactions that manage the natural gas commodity and transportation costs in an attempt to achieve the lowest cost to serve its various markets. Sequent seeks to optimize this process on a daily basis as market conditions change by evaluating all the natural gas supplies, transportation alternatives and markets to which it has access and identifying the least-cost alternatives to serve the various markets. This enables Sequent to capture geographic pricing differences across these various markets as delivered natural gas prices change.

As Sequent executes transactions to secure transportation capacity, it often enters into forward financial contracts to hedge its positions. The hedging instruments are derivatives, and Sequent reflects changes in the derivatives' fair value in its reported operating results. During 2007, Sequent reported unrealized gains of $5 million associated with transportation capacity hedges, most of which are expected to be realized as these positions are settled in 2008. During 2006, Sequent reported unrealized gains of $12 million associated with transportation capacity hedges. The majority of this amount was realized during 2007 as the positions were settled. Sequent did not report any significant gains or losses on these types of hedges during 2005.

Producer Services Sequent's 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. Sequent provides producers with certain logistical and risk management services that offer producers attractive options to move their supply into the pipeline grid. Aggregating volumes of natural gas from these producers allows Sequent to provide markets to producers who seek a reliable outlet for their natural gas production.

Park and Loan Transactions Sequent routinely enters into park and loan transactions with various pipelines, which allow it 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 in much the same 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. While the hedging instruments mitigate the price risk associated with the delivery and receipt of natural gas, they can also result in volatility in Sequent's reported results during the period before the initial delivery or receipt of natural gas. During this period, if the forward NYMEX prices in the months of delivery and receipt do not change in equal amounts, Sequent will report a net unrealized gain or loss on the hedges.

Although Sequent's quarterly results were modestly impacted by unrealized hedge losses during 2007 and 2006, on an annual basis Sequent did not report any significant gains or losses on park and loan hedges during 2007, 2006, or 2005.

Mark-to-Market Versus Lower of Average Cost or Market Sequent purchases natural gas for storage when the current market price it pays plus the cost for transportation and storage is less than the market price it could receive in the future. Sequent attempts to mitigate substantially all of the commodity price risk associated with its storage portfolio and uses derivative instruments to reduce the risk associated with future changes in the price of natural gas. Sequent sells NYMEX futures contracts or over-the-counter derivatives in forward months to substantially lock in the operating margin it will ultimately realize when the stored gas is actually sold.

We view Sequent's trading margins from two perspectives. First, we base our commercial decisions on economic value, which is defined as the locked-in gain to be realized in the statement of income at the time the physical gas is withdrawn from storage and ultimately sold and the derivative instrument used to hedge natural gas price risk on that physical storage is settled. Second is the GAAP reported value both prior to and at the point of physical withdrawal. The GAAP amount is impacted by the process of accounting for the financial hedging instruments in interim periods at fair value between the time the natural gas is injected into storage and when it is ultimately withdrawn and the financial instruments are settled. The change in the fair value of the hedging instruments is recognized in earnings in the period of change and is recorded as unrealized gains or losses. The actual value, less any interim recognition of gains or losses on hedges and adjustments for LOCOM, is realized when the natural gas is delivered to its ultimate customer.

Sequent accounts for natural gas stored in inventory differently than the derivatives Sequent uses to mitigate the commodity price risk associated with its storage portfolio. The natural gas that Sequent purchases and injects into storage is accounted for at the lower of average cost or current market value. The derivatives that Sequent uses to mitigate commodity price risk are accounted for at fair value and marked to market each period. This difference in accounting treatment can result in volatility in Sequent's reported results, even though the expected operating margin is essentially unchanged from the date the transactions were consummated. These accounting differences also affect the comparability of Sequent's period-over-period results, since changes in forward NYMEX prices do not increase and decrease on a consistent basis from year to year. During most of 2007 and 2006, Sequent's reported results were positively impacted by decreases in forward NYMEX prices, which resulted in the recognition of unrealized gains; however, the impact was more significant for 2006. During 2005, the reported results were negatively impacted by increases in forward NYMEX prices. As a result the more significant unrealized gains during 2006 increased the unfavorable variance between 2007 and 2006 and had a positive impact on the favorable variance between 2006 and 2005.

Energy Investments

Our energy investments segment includes a number of businesses that are related and complementary to our primary business. The most significant of these businesses is our natural gas storage business, which develops, acquires and operates high-deliverability salt-dome storage assets in the Gulf Coast region of the United States. While this business also can generate additional revenue during times of peak market demand for natural gas storage services, the majority of our storage services are covered under medium to long-term contracts at a fixed market rate.

Jefferson Island This wholly owned subsidiary operates a salt dome storage and hub facility in Louisiana, approximately eight miles from the Henry Hub. The storage facility is regulated by the Louisiana DNR and by the FERC, which has limited regulatory authority over the storage and transportation services. The facility consists of two salt dome gas storage caverns with approximately 9.72 Bcf of total capacity and about 7.23 Bcf of working gas capacity. The facility has approximately 0.72 Bcf/day withdrawal capacity and 0.36 Bcf/day injection capacity. Jefferson Island provides storage and hub services through its direct connection to the Henry Hub via the Sabine Pipeline and its interconnection with seven other pipelines in the area. Jefferson Island's entire portfolio is under firm subscription for the current heating season.

In August 2006, the Office of Mineral Resources of the Louisiana DNR informed Jefferson Island that its mineral lease – which authorizes salt extraction to create two new storage caverns – at Lake Peigneur had been terminated. The Louisiana DNR identified two bases for the termination: (1) failure to make certain mining leasehold payments in a timely manner, and (2) the absence of salt mining operations for six months.

In September 2006, Jefferson Island filed suit against the State of Louisiana to maintain its lease to complete an ongoing natural gas storage expansion project in Louisiana. The project would add two salt dome storage caverns under Lake Peigneur to the two caverns currently owned and operated by Jefferson Island. In its suit, Jefferson Island alleges that the Louisiana DNR accepted all leasehold payments without reservation and never provided Jefferson Island with notice and opportunity to cure, as required by state law. In its answer to the suit, the State denied that anyone with proper authority approved late payments. As to the second basis for termination, the suit contends that Jefferson Island's lease with the State of Louisiana was amended in 2004 so that mining operations are no longer required to maintain the lease. The State's answer denies that the 2004 amendment was properly authorized. During early 2008 we plan to intensify our efforts with the state of Louisiana to move the expansion project forward. If we are unable to reach a settlement, we are not able to predict the outcome of the litigation. As of January 2008, our current estimate of costs incurred that would be considered unusable if the Louisiana DNR was successful in terminating our lease and causing us to cease the expansion project is approximately $6 million.

Golden Triangle Storage In December 2006, we announced that our wholly-owned subsidiary, Golden Triangle Storage, plans to build a natural gas storage facility in the Beaumont, Texas area in the Spindletop salt dome. The project will initially consist of two underground salt dome storage caverns approximately a half-mile to a mile below ground that will hold about 12 Bcf of working natural gas storage capacity initially, or a total cavern capacity of approximately 17 Bcf. The facility potentially can be expanded to a total of five caverns with 28 Bcf of working natural gas storage capacity in the future based on customer interest. Golden Triangle Storage also intends to build an approximately nine-mile natural gas pipeline to connect the storage facility with three interstate and three intrastate pipelines. In May 2007, Golden Triangle Storage held a non-binding open season for service offerings at the proposed facility, which resulted in indications of market support for the facility.

Our current cost estimate for this facility is up to $265 million, but the actual cost will depend upon the facility's configuration, materials and drilling costs, the amount and cost of pad gas (which includes volumes of non-working natural gas used to maintain the operational integrity of the cavern facility), and financing costs. This estimate could change due to changes in these factors, among others, as we refine our engineering estimates.

In December 2007, Golden Triangle Storage received an order from the FERC granting a Certificate of Public Convenience and Necessity to construct and operate the storage facility and approving market-based rates for services to be provided. We accepted this FERC order in January 2008. The FERC will serve as the lead agency overseeing the participation of a number of other federal, state and local agencies in reviewing and permitting the facility. Timelines associated with our commencement of commercial operations remain on track with initial construction on the first cavern expected to begin in the first half of 2008.

AGL Networks This wholly owned subsidiary provides 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 one to twenty years. In addition, AGL Networks offers telecommunications construction services to its customers. AGL Networks' competitors are any entities that have laid or will lay conduit and fiber on the same route as AGL Networks in the respective metropolitan areas.

Corporate

Our corporate segment includes our nonoperating business units, including AGSC and AGL Capital. AGL Capital, our wholly owned subsidiary, provides for our ongoing financing needs through a commercial paper program, the issuance of various debt and hybrid securities, and other financing arrangements.

We allocate substantially all of AGSC's operating expenses and interest costs to our operating segments in accordance with various regulations. Our corporate segment also includes intercompany eliminations for transactions between our operating business segments. Our EBIT results include the impact of these allocations to the various operating segments. The acquisition of additional assets, such as NUI and Jefferson Island, typically enables us to allocate corporate costs across a larger number of businesses and, as a result, lower the relative allocations charged to those business units we owned prior to the acquisition of the new businesses.

Our corporate segment also includes Pivotal Energy Development, which coordinates among our related operating segments the development, construction or acquisition of assets in the southeastern, mid-Atlantic and northeastern regions in order to extend our natural gas capabilities and improve system reliability while enhancing service to our customers in those areas. The focus of Pivotal Energy Development's commercial activities is to improve the economics of system reliability and natural gas deliverability in these targeted regions.

Additional Information

For additional information on our segments, see Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations” under the caption “Results of Operations” and “Note 9, Segment Information,” set forth in Item 8, “Financial Statements and Supplementary Data.”

Information on our environmental remediation efforts, is contained in “Note 7, Commitments and Contingencies,” set forth in Item 8, “Financial Statements and Supplementary Data.”

Hedges

Changes in commodity prices subject a significant portion of our operations to earnings variability. Our nonutility businesses principally use physical and financial arrangements to reduce the risks associated with both weather-related seasonal fluctuations and changing commodity prices. In addition, because these economic hedges are generally not designated for hedge accounting treatment, our reported earnings for the wholesale services and retail energy operations segments reflect changes in the fair values of certain derivatives. These values may change significantly from period to period and are reflected as gains or losses within our operating margin or our OCI for those derivative instruments that qualify and are designated as accounting hedges.

Seasonality

The operating revenues and EBIT of our distribution operations, retail energy operations and wholesale services segments are seasonal. During the heating season, natural gas usage and operating revenues are generally higher because more customers are connected to our distribution systems and natural gas usage is higher in periods of colder weather than in periods of warmer weather.

Approximately 61% of these segments’ operating revenues and 69% of these segments’ EBIT for the year ended December 31, 2007 were generated during the heating season and are reflected in our statements of consolidated income for the quarters ended March 31, 2007 and December 31, 2007. Our base operating expenses, excluding cost of gas, interest expense and certain incentive compensation costs, are incurred relatively equally over any given year. Thus, our operating results vary significantly from quarter to quarter as a result of seasonality. Seasonality also affects the comparison of certain balance sheet items such as receivables, unbilled revenue, inventories and short-term debt across quarters. However, these items are comparable when reviewing our annual results.

Available Information

Detailed information about us is contained in our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and other reports, and amendments to those reports, that we file with or furnish to the SEC. These reports are available free of charge at our website, www.aglresources.com, as soon as reasonably practicable after we electronically file such reports with or furnish such reports to the SEC. However, our website and any contents thereof should not be considered to be incorporated by reference into this document. We will furnish copies of such reports free of charge upon written request to our Investor Relations department. You can contact our Investor Relations department at:

AGL Resources Inc.
Investor Relations - Dept. 1071
P.O. Box 4569
Atlanta, GA 30309-4569
404-584-3801

In Part III of this Form 10-K, we incorporate by reference from our Proxy Statement for our 2008 annual meeting of shareholders certain information. We expect to file that Proxy Statement with the SEC on or about March 19, 2008, and we will make it available on our website as soon as reasonably practicable. Please refer to the Proxy Statement when it is available.

Additionally, our corporate governance guidelines, code of ethics, code of business conduct and the charters of each of our Board of Directors committees are available on our website. We will furnish copies of such information free of charge upon written request to our Investor Relations department.

ITEM 1A. RISK FACTORS

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Certain expectations and projections regarding our future performance referenced in this report, in other materials we file with the SEC or otherwise release to the public, and on our website are forward-looking statements. Senior 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 statements in "Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere regarding our future operations, prospects, strategies, financial condition, economic performance (including growth and earnings), industry conditions and demand for our products and services. We have tried, whenever possible, to identify these statements by using words such as "anticipate," "assume," "believe," "can," "could," "estimate," "expect," "forecast," "future," "goal," "indicate," "intend," "may," "outlook," "plan," "potential," "predict," "project," "seek," "should," "target," "will," "would," and similar expressions.

You are cautioned not to place undue reliance on our forward-looking statements. Our forward-looking statements are not guarantees of future performance and are based on currently available competitive, financial and economic data along with our operating plans. While we believe that our expectations for the future are reasonable in view of the currently available information, our expectations are subject to future events, risks and inherent uncertainties, as well as potentially inaccurate assumptions, and there are numerous factors - many beyond our control - that could cause results to differ significantly from our expectations. Such events, risks and uncertainties include, but are not limited to those set forth below and in the other documents that we file with the SEC. We note these factors for investors as permitted by the Private Securities Litigation Reform Act of 1995. There also may be other factors that we cannot anticipate or that are not described in this report, generally because we do not perceive them to be material, which 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 circumstances or events. You are advised, however, to review any further disclosures we make on related subjects in our Form 10-Q and Form 8-K reports to the SEC.

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, at the federal level our businesses are regulated by the FERC. At the state level, our businesses are regulated by the Georgia Commission, the Tennessee Commission, the New Jersey Commission, the Florida Commission, the Virginia Commission and the Maryland Commission.

These authorities regulate many aspects of our operations, including construction and maintenance of facilities, operations, safety, rates that we charge customers, rates of return, the authorized cost of capital, recovery of pipeline replacement and environmental remediation costs, relationships with our affiliates, and carrying costs we charge Marketers selling retail natural gas in Georgia for gas held in storage for their customer accounts. Our ability to obtain rate increases and rate supplements to maintain our current rates of return and recover regulatory assets and liabilities recorded in accordance with SFAS 71 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 including the recovery of our regulatory assets and liabilities. In addition, if we fail to comply with applicable regulations, we could be subject to fines, penalties or other enforcement action by the authorities that regulate our operations, or otherwise be subject to material costs and liabilities.

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 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. 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 or amend portions of the deregulation process and require or permit Atlanta Gas Light to provide retail gas sales service once again or require our retail energy operations segment, SouthStar, to change the nature of how it provides natural gas and the rates used to charge certain customers. In addition, the Georgia Commission has statutory authority on an emergency basis to order Atlanta Gas Light to provide temporarily 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.

Our business is subject to environmental regulation in all jurisdictions in which we operate, and our costs to comply are significant. Any changes in existing environmental regulation could 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 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.

There are a number of legislative and regulatory proposals to address greenhouse gas emissions such as carbon dioxide, which are in various phases of discussion or implementation. The outcome of federal and state actions to address global climate change could result in a variety of regulatory programs including potential new regulations, additional charges to fund energy efficiency activities, or other regulatory actions. These actions could:

- result in increased costs associated with our operations
- Increase other costs to our business
- affect the demand for natural gas and
- impact the prices we charge our customers.

Because natural gas is a fossil fuel with low carbon content, it is possible that future carbon constraints could create additional demand for natural gas, both for production of electricity and direct use in homes and businesses.

Our infrastructure improvement and customer growth may be restricted by the capital-intensive nature of our business.

We must construct additions to our natural gas distribution system to continue the expansion of our customer base. We may also need to construct expansions of our existing natural gas storage facilities or develop and construct new natural gas storage facilities. The cost of this construction may be affected by the cost of obtaining government and other approvals, development project delays, adequacy of supply of diversified vendors, or unexpected changes in project costs. Weather, general economic conditions and the cost of funds to finance our capital projects can materially alter the cost, and projected construction schedule and completion timeline of a project. Our cash flows may not be fully adequate to finance the cost of this construction. As a result, we may be required to fund a portion of our cash needs through borrowings or the issuance of common stock, or both. For our distribution operations segment, this may limit our ability to expand our infrastructure to connect new customers due to limits on the amount we can economically invest, which shifts costs to potential customers and may make it uneconomical for them to connect to our distribution systems. For our natural gas storage business, this may significantly reduce our earnings and return on investment from what would be expected for this business, or may impair our ability to complete the expansions or development projects.

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.

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

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 natural 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 commercial, industrial and agricultural customers, adverse economic conditions, including higher gas costs, could also cause these customers to bypass or disconnect from our systems in favor of special competitive contracts with lower per-unit costs.

Our wholesale services segment 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 operating margin. 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 operating margin available in this portion of Sequent's business.

A significant portion of our accounts receivable is subject to collection risks, due in part to a concentration of credit risk in Georgia and at Sequent.

We have accounts receivable collection risk in Georgia due to a concentration of credit risk related to the provision of natural gas services to Marketers. At December 31, 2007, Atlanta Gas Light had 12 certificated and active Marketers in Georgia, four of which (based on customer count and including SouthStar) accounted for approximately 38% of our consolidated operating margin for 2007. As a result, Atlanta Gas Light 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. The provisions of Atlanta Gas Light's tariff allow it to obtain security support in an amount equal to a minimum of two times a Marketer's highest month's estimated bill. Additionally, SouthStar markets directly to end-use customers and has periodically experienced credit losses as a result of severe cold weather or high prices for natural gas that increase customers' bills and, consequently, impair customers' ability to pay.

Sequent often extends credit to its counterparties. Despite performing credit analyses prior to extending credit and seeking to effectuate netting agreements, Sequent is exposed to the risk that it may not be able to collect amounts owed to it. If the counterparty to such a transaction fails to perform and any collateral Sequent has secured is inadequate, Sequent could experience material financial losses. Further, Sequent has a concentration of credit risk, which could subject a significant portion of its credit exposure to collection risks. Approximately 53% 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 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.

The asset management arrangements between Sequent and our 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, Chattanooga Gas, Elizabethtown Gas, Elkton Gas, Florida City Gas, and Virginia Natural Gas and shares profits it earns from the management of those assets with those customers and their respective customers, except at Elizabethtown Gas and Elkton Gas where Sequent is assessed annual fixed-fees payable in monthly installments. Additionally, for the newly extended Atlanta Gas Light asset management agreement, Sequent will be required to make annual minimum payments of approximately $4 million payable on a quarterly basis. Entry into and renewal of these agreements are subject to regulatory approval and four are subject to renewal in 2008. In addition, Sequent has asset management agreements with certain nonaffiliated customers. Sequent's results could be significantly impacted if these agreements are not renewed or are amended or renewed with less favorable terms.

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

The commodity, storage and transportation portfolios at Sequent and the commodity and storage portfolios at SouthStar 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. Based on a 95% confidence interval and employing a 1-day holding period for all positions, Sequent's and SouthStar's portfolio of positions as of December 31, 2007 had a 1-day holding period VaR of $1.2 million and $0.03 million, respectively.

Our accounting results may not be indicative of the risks we are taking or the economic results we expect 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 correspond to the profits or losses on the item being hedged. The difference in accounting can result in volatility in Sequent's reported results, even though the expected operating margin is essentially unchanged from the date the transactions were consummated.

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, during either the winter period or summer period, can have a significant impact on demand for and cost of natural gas.

We have a WNA mechanism for Elizabethtown Gas and Chattanooga Gas that partially offsets the impact of unusually cold or warm weather on residential and commercial customer billings and our operating margin. At Elizabethtown Gas we could be required to return a portion of any WNA surcharge to its customers if Elizabethtown Gas' return on equity exceeds its authorized return on equity of 10%.

Additionally, Virginia Natural Gas has a WNA mechanism for its residential customers that partially offsets the impact of unusually cold or warm weather. In September 2007, the Virginia Commission approved Virginia Natural Gas' application for an Experimental Weather Normalization Adjustment Rider (the Rider) for its commercial customers. The Rider applies to the 2007 and 2008 heating seasons, with an opportunity for Virginia Natural Gas to extend the Rider for additional years.

These WNA regulatory mechanisms are 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.

Changes in weather conditions may also impact SouthStar's earnings. As a result, SouthStar uses a variety of weather derivative instruments to mitigate the impact on its operating margin in the event of warmer than normal weather in the winter months. However, these instruments do not fully protect SouthStar's earnings from the effects of unusually warm weather.

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.

Our profitability may decline if the counterparties to Sequent's asset management transactions fail to perform in accordance with Sequent's agreements.

Sequent 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. Sequent 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. In such events, we might incur additional losses to the extent of amounts, if any, already paid to or received from counterparties.

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, we manufactured gas from coal and other fuels. Those manufacturing operations were known as MGPs, which we ceased operating in the 1950s.

We have identified ten sites in Georgia and three in Florida where we own 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. As of December 31, 2006, the soil and sediment remediation program was complete for all Georgia sites, although groundwater cleanup continues. As of December 31, 2007, projected costs associated with the MGP sites associated with Atlanta Gas Light were $35 million. For elements of the MGP program where we still cannot provide engineering cost estimates, considerable variability remains in future cost estimates.

In addition, we are associated with former sites in New Jersey, North Carolina and other states that we assumed with our acquisition of NUI in November 2004. Material cleanups of these sites have not been completed nor are precise estimates available for future cleanup costs and therefore considerable variability remains in future cost estimates. For the New Jersey sites, cleanup cost estimates range from $61 million to $119 million. Costs have been estimated for only one of the non-New Jersey sites, for which current estimates range from $11 million to $20 million.

Inflation and increased gas costs could adversely impact our ability to control operating expenses, increase our level of indebtedness and adversely impact our customer base.

Inflation has caused increases in certain operating expenses that have required us to replace assets at higher costs. We attempt to control costs in part through implementation of best practices and business process improvements, many of which are facilitated through investments in information systems and technology. 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 we intend to continue to do so. However, any inability by us to control our expenses in a reasonable manner would adversely influence our future results.

Rapid increases in the price of purchased gas 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 results in higher short-term debt levels and increased bad debt expense. Should the price of purchased gas increase significantly during the upcoming heating season, we would expect increases in our short-term debt, accounts receivable and bad debt expense during 2008.

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 or switching to other competing products. The higher costs have also allowed competition from products utilizing alternative energy sources for applications that have traditionally used natural gas, encouraging some customers to move away from natural gas fired equipment to equipment fueled by other energy sources.

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

We have defined benefit pension and postretirement health care benefit plans for the benefit of substantially all full-time employees and qualified retirees. 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, changing demographics, including longer life expectancy of beneficiaries, changes in health care cost trends, and an expected increase in the number of eligible former employees over the next five years.

Any sustained declines in equity markets and reductions in bond yields may 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 consolidated income to the extent that the pension fund values are less than the total anticipated liability under the plans.

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.

Risks Related to Our Corporate and Financial Structure

We depend on our ability to successfully access the capital and financial 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 lines of credit) 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
- significant decrease in the demand for natural gas
- adverse regulatory actions that affect our local gas distribution companies and our natural gas storage business
- terrorist attacks on our facilities or our suppliers
- extreme weather conditions

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

Our existing Credit Facility and the SouthStar line of credit contain financial covenants. If we 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.

A downgrade in our credit rating could negatively affect our ability to access capital.

Our senior unsecured debt is currently assigned a rating of BBB+ by S&P, Baa1 by Moody’s and A- by Fitch. Our commercial paper currently is rated A2 by S&P, P2 by Moody’s and F2 by Fitch. 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, 2007, if our credit rating had fallen below investment grade, we would have been required to provide collateral of approximately $26 million to continue conducting our wholesale services business with certain counterparties.

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

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 Item 7A, "Quantitative and Qualitative Disclosures About Market Risk." We cannot ensure that we will be successful in structuring such swap agreements to manage our risks effectively. 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.

We are a holding company and are dependent on cash flow from our subsidiaries, which may not be available in the amounts and at the times we need.

A portion of our outstanding debt was issued by our wholly-owned subsidiary, AGL Capital, which we fully and unconditionally guarantee. Since we are a holding company and have no operations separate from our investment in our subsidiaries, we are dependent on cash in the form of dividends or other distributions from our subsidiaries to meet our cash requirements. The ability of our subsidiaries to pay dividends and make other distributions is subject to applicable state law. Refer to Item 5 "Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities" for additional dividend restriction information.

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.

As a result of cross-default provisions in our borrowing arrangements, we may be unable to satisfy all our outstanding obligations in the event of a default on our part.

Our Credit Facility under which our debt is issued contains 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 our outstanding obligations simultaneously.

ITEM 1B. UNRESOLVED STAFF COMMENTS

We do not have any unresolved comments from the SEC staff regarding our periodic or current reports under the Securities Exchange Act of 1934, as amended.

ITEM 2. PROPERTIES

Distribution Operations As of December 31, 2007, the properties of our distribution operations segment represented approximately 91% of the net property, plant and equipment in our consolidated balance sheet. This property primarily includes assets used for the distribution of natural gas to our customers in our service areas, including more than 44,000 miles of distribution and transmission mains. We have approximately 7.35 Bcf of LNG storage capacity in five LNG plants located in Georgia, New Jersey and Tennessee. In addition, we own three propane storage facilities in Virginia and Georgia that have a combined storage capacity of approximately 4.5 million gallons. These LNG plants and propane facilities supplement the gas supply during peak usage periods.

Energy Investments The properties in our energy investments segment are primarily investments that are complementary to our distribution operations or provide services consistent with our core enterprises, including a natural gas storage and hub facility in Louisiana located approximately eight miles from the Henry Hub. The Henry Hub is the largest centralized point for natural gas spot and futures trading in the United States. The NYMEX uses the Henry Hub as the point of delivery for its natural gas futures contracts. Many natural gas marketers also use the Henry Hub as their physical contract delivery point or their price benchmark for spot trades of natural gas. Our natural gas storage and hub facility consists of two salt dome gas storage caverns with approximately 9.72 Bcf of total capacity and about 7.23 Bcf of working gas capacity. The facility has approximately 0.72 Bcf/day withdrawal capacity and 0.36 Bcf/day injection capacity. We completed a project during 2005 to expand compression capability, enabling us to increase the number of times a customer can inject and withdraw their total gas inventory annually from 10 to 12.

In addition, energy investments' properties include telecommunications conduit and fiber in public rights-of-way that are leased to our customers primarily in Atlanta and Phoenix. This includes over 93,000 fiber miles, a 17,000 mile increase compared to 2006, of which approximately 29% of our dark fiber in Atlanta and 28% of our dark fiber in Phoenix has been leased.

Retail Energy Operations, Wholesale Services and Corporate The properties used at our retail energy operations, wholesale services and corporate segments consist primarily of leased and owned office space in Atlanta and Houston and their contents, including furniture and fixtures. The majority of our Atlanta-based employees are located at our corporate headquarters, a leased building with approximately 227,000 square feet of office space. In addition, our retail energy operations segment leases approximately 30,200 square feet at another office building in Atlanta. We lease approximately 50,000 square feet of office space for our employees in Houston.

We own or lease additional office, warehouse and other facilities throughout our operating areas. We consider our properties and the properties of our subsidiaries to be well maintained, in good operating condition and suitable for their intended purpose. We expect additional or substitute space to be available as needed to accommodate expansion of our operations.

ITEM 3. LEGAL PROCEEDINGS

The nature of our business ordinarily results in periodic regulatory proceedings before various state and federal authorities. In addition, we are party, as both plaintiff and defendant, to a number of lawsuits related to our business on an ongoing basis. Management believes that the outcome of all regulatory proceedings and litigation in which we are currently involved will not have a material adverse effect on our consolidated financial condition or results of operations. Information regarding some of these proceedings is contained in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Results of Operations" and in Note 7 "Commitments and Contingencies" to our consolidated financial statements under the caption "Litigation" set forth in Item 8, "Financial Statements and Supplementary Data."

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

No matters were submitted to a vote of our security holders during the fourth quarter ended December 31, 2007.

EXECUTIVE OFFICERS OF THE REGISTRANT

Set forth below are the names, ages and positions of our executive officers along with their business experience during the past five years. All officers serve at the discretion of our Board of Directors. All information is as of the date of the filing of this report.

Name, age and position with the company	Periods served
John W. Somerhalder II, Age 52 (1)	
Chairman, President and Chief Executive Officer	October 2007 - Present
President and Chief Executive Officer	March 2006 – October 2007
Andrew W. Evans, Age 41	
Executive Vice President and Chief Financial Officer	May 2006 – Present
Senior Vice President and Chief Financial Officer	September 2005 – May 2006
Vice President and Treasurer	April 2002 – September 2005
Ralph Cleveland, Age 45	
Senior Vice President, Engineering and Operations	November 2004 - Present
Vice President, Engineering and Construction	June 2002 – November 2004
Henry P. Linginfelter, Age 47	
Executive Vice President, Utility Operations	June 2007 - Present
Senior Vice President, Mid-Atlantic Operations	November 2004– June 2007
President, Virginia Natural Gas, Inc.	October 2000 – November 2004
Kevin P. Madden, Age 55	
Executive Vice President, External Affairs	November 2005 – Present
Executive Vice President, Distribution and Pipeline Operations	April 2002 – November 2005
Melanie M. Platt, Age 53	
Senior Vice President, Human Resources	September 2004 – Present
Senior Vice President and Chief Administrative Officer	November 2002 – September 2004
Douglas N. Schantz, Age 52 (2)	
President, Sequent Energy Management, L.P.	May 2003 – Present
Paul R. Shlanta, Age 50	
Executive Vice President, General Counsel and Chief Ethics and Compliance Officer	September 2005 – Present
Senior Vice President, General Counsel and Chief Corporate Compliance Officer	September 2002 – September 2005

(1) Mr. Somerhalder was executive vice president of El Paso Corporation (NYSE: EP) from 2000 until May 2005, and he continued service under a professional services agreement from May 2005 until March 2006.

(2) Mr. Schantz served as vice president of the gas origination division at Cinergy Marketing & Trading, LP, an affiliate of Cinergy Corp (NYSE: CIN) from September 2000 to April 2003.

PART II

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

Holders of Common Stock, Stock Price and Dividend Information

Our common stock is listed on the New York Stock Exchange under the symbol ATG. At January 31, 2008, there were 10,697 record holders of our common stock. Quarterly information concerning our high and low stock prices and cash dividends paid in 2007 and 2006 is as follows:

	Sales price of common stock		Cash dividend per common
Quarter ended:	**High**	**Low**	**share**
2007			
March 31, 2007	$42.99	$38.20	$0.41
June 30, 2007	44.67	39.52	0.41
September 30, 2007	41.51	35.24	0.41
December 31, 2007	41.16	35.42	0.41
			$1.64
2006			
March 31, 2006	$36.48	$34.40	$0.37
June 30, 2006	38.13	34.43	0.37
September 30, 2006	40.00	34.76	0.37
December 31, 2006	40.09	36.04	0.37
			$1.48

We have historically paid dividends to common shareholders four times a year: March 1, June 1, September 1 and December 1. We have paid 240 consecutive quarterly dividends beginning in 1948. Our common shareholders may receive dividends when declared at the discretion of our Board of Directors. See Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Cash Flow from Financing Activities – Dividends on Common Stock." Dividends may be paid in cash, stock or other form of payment, and payment of future dividends will depend on our future earnings, cash flow, financial requirements and other factors, some of which are noted below. In certain cases, our ability to pay dividends to our common shareholders is limited by the following:

- our ability to satisfy our obligations under certain financing agreements, including debt-to-capitalization and total shareholders' equity covenants
- our ability to satisfy our obligations to any preferred shareholders

Under Georgia law, the payment of cash 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. Our assets are not legally available for paying cash dividends if, after payment of the dividend:

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

Issuer Purchases of Equity Securities

The following table sets forth information regarding purchases of our common stock by us and any affiliated purchasers during the three months ended December 31, 2007. Stock repurchases may be made in the open market or in private transactions at times and in amounts that we deem appropriate. However, there is no guarantee as to the exact number of additional shares that may be repurchased, and we may terminate or limit the stock repurchase program at any time. We will hold the repurchased shares as treasury shares.

Period	Total number of shares purchased (1) (2) (3)	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs (3)	Maximum number of shares that may yet be purchased under the publicly announced plans or programs (3)
October 2007	446,788	$38.99	446,788	5,084,912
November 2007	133,961	38.63	133,961	4,950,951
December 2007	2,592	37.48	-	4,950,951
Total fourth quarter	583,341	$38.90	580,749	

(1) The total number of shares purchased includes an aggregate of 2,592 shares surrendered to us to satisfy tax withholding obligations in connection with the vesting of shares of restricted stock and/or the exercise of stock options.

(2) On March 20, 2001, our Board of Directors approved the purchase of up to 600,000 shares of our common stock in the open market to be used for issuances under the Officer Incentive Plan (Officer Plan). We did not purchase any shares for such purposes in the fourth quarter of 2007. As of December 31, 2007, we had purchased a total 297,234 of the 600,000 shares authorized for purchase, leaving 302,766 shares available for purchase under this program.

(3) On February 3, 2006, we announced that our Board of Directors had authorized a plan to repurchase up to a total of 8 million shares of our common stock, excluding the shares remaining available for purchase in connection with the Officer Plan as described in note (2) above, over a five-year period.

The information required by this item regarding securities authorized for issuance under our equity compensation plans will be set forth under the caption “Executive Compensation – Equity Compensation Plan Information” in the Proxy Statement for our 2008 Annual Meeting of Shareholders or in a subsequent amendment to this report. All such information will be incorporated by reference from the Proxy Statement in Item 12, “Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters” hereof or set forth in such amendment to this report.

ITEM 6. SELECTED FINANCIAL DATA

Selected financial data about AGL Resources for the last five years is set forth in the table below. You should read the data in the table in conjunction with the consolidated financial statements and related notes set forth in Item 8, "Financial Statements and Supplementary Data."

Dollars and shares in millions, except per share amounts	2007	2006	2005	2004	2003
Income statement data					
Operating revenues	$2,494	$2,621	$2,718	$1,832	$983
Cost of gas	1,369	1,482	1,626	995	339
Operating margin (1)	1,125	1,139	1,092	837	644
Operating expenses					
Operation and maintenance	451	473	477	377	283
Depreciation and amortization	144	138	133	99	91
Taxes other than income taxes	41	40	40	29	28
Total operating expenses	636	651	650	505	402
Gain on sale of Caroline Street campus	-	-	-	-	16
Operating income	489	488	442	332	258
Equity in earnings of SouthStar Energy Services LLC	-	-	-	-	46
Other income (expense)	4	(1)	(1)	-	(6)
Minority interest	(30)	(23)	(22)	(18)	-
Earnings before interest and taxes (EBIT) (1)	463	464	419	314	298
Interest expense	125	123	109	71	75
Earnings before income taxes	338	341	310	243	223
Income taxes	127	129	117	90	87
Income before cumulative effect of change in accounting principle	211	212	193	153	136
Cumulative effect of change in accounting principle, net of $5 in income taxes	-	-	-	-	(8)
Net income	$211	$212	$193	$153	$128
Common stock data					
Weighted average shares outstanding basic	77.1	77.6	77.3	66.3	63.1
Weighted average shares outstanding diluted	77.4	78.0	77.8	67.0	63.7
Total shares outstanding (2)	76.4	77.7	77.8	76.7	64.5
Earnings per share - basic	$2.74	$2.73	$2.50	$2.30	$2.03
Earnings per share - diluted	$2.72	$2.72	$2.48	$2.28	$2.01
Dividends declared per share	$1.64	$1.48	$1.30	$1.15	$1.11
Dividend payout ratio	60%	54%	52%	50%	55%
Dividend yield	4.4%	3.8%	3.7%	3.5%	3.8%
Book value per share (3)	$21.74	$20.72	$19.27	$18.04	$14.66
Price-earnings ratio	13.7	14.3	13.9	14.5	14.3
Stock price market range	$35.24- $44.67	$34.40- $40.09	$32.00- $39.32	$26.50- $33.65	$21.90- $29.35
Market value per share (4)	$37.64	$38.91	$34.81	$33.24	$29.10
Market value (2)	$2,876	$3,023	$2,708	$2,551	$1,877
Balance sheet data (2)					
Total assets	$6,268	$6,147	$6,320	$5,637	$3,972
Property, plant and equipment – net	3,566	3,436	3,333	3,178	2,345
Working capital	166	156	73	(20)	(306)
Total debt	2,254	2,161	2,137	1,957	1,340
Common shareholders' equity	1,661	1,609	1,499	1,385	945
Cash flow data					
Net cash provided by operating activities	$376	$354	$80	$287	$122
Property, plant and equipment expenditures	259	253	267	264	158
Net borrowings and (payments) of short-term debt	52	6	188	(480)	(82)
Financial ratios (2)					
Total debt	58%	57%	59%	59%	59%
Common shareholders' equity	42%	43%	41%	41%	41%
Total	100%	100%	100%	100%	100%
Return on average common shareholders' equity	12.9%	13.6%	13.4%	13.1%	15.5%

(1) These are non-GAAP measurements. A reconciliation of operating margin and EBIT to our operating income and net income is contained in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations-AGL Resources-Results of Operations."
(2) As of the last day of the fiscal period.
(3) Common shareholders' equity divided by total outstanding common shares as of the last day of the fiscal period.
(4) Closing price of common stock on the New York Stock Exchange as of the last trading day of the fiscal period.

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

Overview

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 southeastern and mid-Atlantic regions of the United States based on customer count. We are involved in various related businesses, including retail natural gas marketing to end-use customers primarily in Georgia; natural gas asset management and related logistics activities for our own utilities as well as for nonaffiliated companies; natural gas storage arbitrage and related activities; and the development and operation of high-deliverability underground natural gas storage assets. We also own and operate a small telecommunications business that constructs and operates conduit and fiber infrastructure within select metropolitan areas. We manage these businesses through four operating segments – distribution operations, retail energy operations, wholesale services and energy investments – and a nonoperating corporate segment. As of January 31, 2008, we employed a total of 2,332 employees across these five segments.

The distribution operations segment is the largest component of our business and is subject to regulation and oversight by agencies in each of the six states we serve. These agencies approve natural gas rates designed to provide us the opportunity to generate revenues to recover the cost of natural gas delivered to our customers and our fixed and variable costs such as depreciation, interest, maintenance and overhead costs, and to earn a reasonable return for our shareholders. With the exception of Atlanta Gas Light, our largest utility, the earnings of our regulated utilities can be affected by customer consumption patterns that are a function of weather conditions and price levels for natural gas. Various mechanisms exist that limit our exposure to weather changes within typical ranges in all of our jurisdictions. Our retail energy operations segment, which consists of SouthStar, also is weather sensitive and uses a variety of hedging strategies, such as weather derivative instruments and other risk management tools, to mitigate potential weather impacts. Our Sequent subsidiary within our wholesale services segment is relatively temperature sensitive, but has greater opportunity to capture margin as price volatility increases. Our energy investments segment's primary activity is our natural gas storage business, which develops, acquires and operates high-deliverability salt-dome storage assets in the Gulf Coast region of the United States. While this business also can generate additional revenue during times of peak market demand for natural gas storage services, the majority of our storage services are covered under medium to long-term contracts at a fixed market rate.

Executive Summary

In support of our goals for 2007, we focused our efforts around five key operating priorities as discussed below.

Marketing and customer retention investments in distribution operations and retail energy operations

We targeted overall net customer growth rates for our distribution operations business in the range of 1% to 1.5%. In each of our utility service areas, we implemented targeted marketing and growth programs aimed at emphasizing natural gas as the fuel of choice for customers and expanding the use of natural gas through a variety of promotional activities. In 2007, we grew our average customer count by approximately 21,000, a 0.9% increase as compared to last year. While this increase is slightly below our targeted range, the increase in the growth rate is an improvement over our relatively flat customer growth in 2006. Last year we had slower customer growth coming out of the winter heating season due in part to much higher natural gas prices, warmer weather and a higher average customer attrition rate of 1.9% in 2006 as compared to 1.2% in 2007, which reflects a 37% improvement. Our customer growth rate was negatively impacted by the downturn in the housing market during 2007; factors which are expected to continue to have a negative impact on customer growth in 2008. We continue to focus significant efforts in our distribution operations business on improving our net customer growth trends, despite the overall economy and the industry-wide challenges of rising natural gas prices, competition from alternative fuels and declining natural gas usage per customer.

These factors also impact customer growth at SouthStar where we are also focused on similar customer growth initiatives. We will continue to enter new markets and improve the overall profitability of its customers through a variety of enhancements to existing, and the implementation of new, product offerings and pricing plans. In 2007, SouthStar grew its average customer count by approximately 7,000 or a 1.3% increase over last year.

Return to normal weather and usage patterns

In 2007, we saw average customer usage patterns related to natural gas price and weather conditions return to levels more consistent with historical averages. As the weather grew colder, compared to last year, and moved closer to 10-year average weather patterns primarily in Maryland, New Jersey and Virginia, we saw the conservation that occurred a year ago largely reverse itself and return to expected levels. Due to these factors, coupled with our targeted marketing and growth programs mentioned above, our overall throughput in 2007 at distribution operations increased 1% as compared to prior year and 3% at SouthStar for its customers in Georgia. While we saw these improvements in throughput and weather that was colder than last year by 10% in Maryland, 17% in New Jersey and 6% in Virginia, weather did not completely return to normal and consequently our earnings continue to be negatively impacted by warmer-than-normal weather. We attempt to stabilize and mitigate the impact to our earnings due to weather through hedging activities at SouthStar and through WNA regulatory mechanisms in distribution operations. While our hedging activities in 2007 at SouthStar largely offset the negative impact to earnings due to weather that was warmer than normal, distribution operations earnings were negatively impacted by $9 million due to weather that was warmer than normal and because the WNA regulatory mechanisms did not completely offset the negative impact to earnings from decreased consumption resulting from the warmer weather. These WNA regulatory mechanisms are most effective in reasonable temperature ranges relative to normal weather using historical averages due in part to their inherent design but also due to customer consumption patterns that are affected by weather conditions other than temperature. These other weather conditions include wind, cloud cover, precipitation and the duration of colder weather, among others, that are not captured in weather normalization adjustments, which are based primarily on average temperatures.

There are a number of legislative and regulatory proposals to address greenhouse gas emissions such as carbon dioxide, which are in various phases of discussion or implementation. We continue to actively monitor these proposals and discussions because the results could negatively impact our operations through reduced demand for natural gas and increased costs to our business. While we are unable to predict the outcome and quantify any impacts from these discussions and proposals at this point, we are active in promoting natural gas as the cleanest and most efficient burning fossil fuel with the lowest carbon content as compared to oil and coal.

Volatility in wholesale markets

Lower volatility in the natural gas markets, as compared to last year, has limited Sequent's asset optimization and arbitrage opportunities to generate operating margin in 2007. An important component of Sequent's business is its ability to capture operating margin based on seasonal and locational spreads, both of which were significantly reduced in 2007 as compared to 2006. We continue to expect less volatility in the natural gas markets and, therefore, we expect Sequent's abilities to capture economic value from asset optimization and arbitrage opportunities to be more consistent with those captured in 2007 as opposed to 2006 and 2005.

Operational efficiency and cost control

We continue to focus on operating our business as efficiently as possible, especially within our distribution operations and corporate segments through control of our operating costs. One of the key metrics we monitor in distribution operations is our operation and maintenance expenses per customer that was $145 per customer for 2007 as compared to $156 per customer in 2006, a 7% decrease year-over-year. This decrease was largely driven by a decrease in incentive compensation for employees at distribution operations and corporate as compared to last year due to lower payouts resulting from lower earnings per share in 2007 as compared to our AIP earning per share goals. Additionally in 2006 our earnings per share results were at the top end of the goals under the AIP, resulting in higher incentive compensation for 2006.

We further utilize outside vendors to assist us with the execution of business processes that are ancillary to our delivery of natural gas and related to the performance of basic business functions. This allows us to control operating costs, increase the efficiency through which these functions are executed and improve our service levels to customers. Most recently, we partnered with third parties in India to provide certain call center operations, as well as certain support functions related to information technology, finance, supply chain and engineering.

New market growth and regulatory opportunities

The four previous operating priorities require us to actively and continuously monitor the emerging issues and trends within our current operations and industry to allow us to take advantage of opportunities that complement and add value to our existing business operations. In 2007, we continued to expand Sequent's operations into the western United States and Canada, as well as SouthStar's operations into Ohio and Florida. Further, in October 2007, we acquired and have included within our wholesale services operating segment Compass Energy, which has enabled us to serve a broader geography of commercial and industrial customers.

Additionally, we continued to focus our efforts around our storage business, particularly our Golden Triangle Storage underground natural gas storage project. We achieved a significant milestone in this project at the end of 2007 as the FERC issued an order granting a Certificate of Public Convenience and Necessity to construct and operate the underground storage project and approving market-based rates for the services Golden Triangle Storage will provide. In January 2008, we accepted the FERC's certificate and expect construction to begin in the first half of 2008.

In distribution operations, we were also successful with certain regulatory initiatives that are critical to the fundamentals of our business as they help to preserve the long-term success and earnings potential of our utility businesses. In September 2007, we received approval from the Georgia Commission on our capacity supply plan in Georgia, and a key part of that agreement was the ability to diversify our supply sources by gaining more access to the Elba Island LNG facility. As a result, we have negotiated an agreement with SNG to obtain an undivided interest in pipelines connecting our Georgia service territory to the Elba Island LNG facility and have filed a joint application with the FERC for approval of the project, which is expected to cost $22 million. In October 2007, the Georgia Commission approved the extension of the asset management agreement between Sequent and Atlanta Gas Light through March 2012. We are actively working with the respective commissions to renew or amend the existing agreements set to expire in 2008 in our other jurisdictions.

In September 2007, the Virginia Commission approved Virginia Natural Gas' WNA rider for commercial customers that applies to the 2007 and 2008 heating seasons. In Florida, we received approval from the Florida Commission in December 2007 to include the amortization of certain components of the purchase price we paid for Florida City Gas in our return on equity calculation for regulatory reporting purposes. Additionally, the Florida Commission's approval included provisions for a five-year stay out. As a result, Florida City Gas' base rates will not change during this period, except for unforeseen events beyond our control and the Florida Commission initiating base rate proceedings.

In November 2007, Elkton Gas filed a base rate case with the Maryland Commission requesting a rate increase of less than $1 million. Starting in 2009 through 2011, we will be required to file base rate cases for Atlanta Gas Light, Virginia Natural Gas, Elizabethtown Gas and Chattanooga Gas. While we are unable to predict the outcome of these base rate proceedings, we will focus on incorporating and potentially proposing regulatory solutions into our base rate filings for many of the areas related to our key operation priorities as well as other emerging issues and trends impacting our utilities.

Results of Operations

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. The following table provides more information regarding the components of our operating revenues.

In millions	2007	2006	2005
Residential	$1,143	$1,127	$1,177
Commercial	500	460	452
Transportation	401	434	450
Industrial	250	310	412
Other	200	290	227
Total operating revenues	$2,494	$2,621	$2,718

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 operating revenues for the contribution resulting from customer growth in our distribution operations segment since the cost of gas can vary significantly and is generally billed directly to our customers. We also consider operating margin to be a better indicator in our retail energy operations, wholesale services and energy investments segments since it is a direct measure of operating margin 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 and EBIT measures may not be comparable to similarly titled measures of other companies. The table below sets forth a reconciliation of our operating margin and EBIT to our operating income and net income, together with other consolidated financial information for the years ended December 31, 2007, 2006 and 2005.

In millions, except per share amounts	**2007**	**2006**	**2005**
Operating revenues	$2,494	$2,621	$2,718
Cost of gas	1,369	1,482	1,626
Operating margin	1,125	1,139	1,092
Operating expenses			
Operation and maintenance	451	473	477
Depreciation and amortization	144	138	133
Taxes other than income	41	40	40
Total operating expenses	636	651	650
Operating income	489	488	442
Other income (expense)	4	(1)	(1)
Minority interest	(30)	(23)	(22)
EBIT	463	464	419
Interest expense	125	123	109
Earnings before income taxes	338	341	310
Income taxes	127	129	117
Net income	$211	$212	$193
Earnings per common share:			
Basic	$2.74	$2.73	$2.50
Diluted	$2.72	$2.72	$2.48
Weighted average number of common shares outstanding:			
Basic	77.1	77.6	77.3
Diluted	77.4	78.0	77.8

Selected weather, customer and volume metrics for 2007, 2006 and 2005, are presented in the following table.

Weather Heating degree days (1)	Normal	Year ended December 31, 2007	2006	2005	2007 vs. 2006 colder (warmer)	2006 vs. 2005 colder (warmer)	2007 vs. normal colder (warmer)	2006 vs. normal colder (warmer)	2005 vs. normal colder (warmer)
Florida	495	326	468	552	(30)%	(15)%	(34)%	(5)%	12%
Georgia	2,582	2,366	2,455	2,739	(4)%	(10)%	(8)%	(5)%	6%
Maryland	4,659	4,621	4,205	4,966	10%	(15)%	(1)%	(10)%	7%
New Jersey	4,588	4,777	4,074	4,931	17%	(17)%	4%	(11)%	7%
Tennessee	2,950	2,722	2,892	3,119	(6)%	(7)%	(8)%	(2)%	6%
Virginia	3,126	3,055	2,870	3,469	6%	(17)%	(2)%	(8)%	11%

(1) Obtained from the National Oceanic and Atmospheric Administration. National Climatic Data Center. Normal represents the ten-year averages from January 1998 to December 2007.

Customers	Year ended December 31, 2007	2006	2005	2007 vs. 2006 % change	2006 vs. 2005 % change
Distribution Operations					
Average end-use customers (in thousands)					
Atlanta Gas Light	1,559	1,546	1,545	0.8%	0.1%
Chattanooga Gas	61	61	61	-	-
Elizabethtown Gas	272	269	266	1.1	1.1
Elkton Gas	6	6	6	-	-
Florida City Gas	104	104	103	-	1.0
Virginia Natural Gas	269	264	261	1.9	1.1
Total	2,271	2,250	2,242	0.9%	0.4%
Operation and maintenance expenses per customer	$145	$156	$166	(7)%	(6)%
EBIT per customer	$149	$138	$133	8%	4%
Retail Energy Operations					
Average customers (in thousands)	540	533	531	1.3%	0.4%
Market share in Georgia	35%	35%	35%	-	-

Volumes In billion cubic feet (Bcf)	Year ended December 31, 2007	2006	2005	2007 vs. 2006 % change	2006 vs. 2005 % change
Distribution Operations					
Firm	211	199	228	6%	(13)%
Interruptible	108	117	117	(8)%	-
Total	319	316	345	1%	(8)%
Retail Energy Operations					
Georgia firm	38.5	37.2	42.6	3%	(13)%
Ohio and Florida	4.5	1.3	-	246%	100%
Wholesale Services					
Daily physical sales (Bcf / day)	2.35	2.20	2.17	7%	1%

Segment information Operating revenues, operating margin, operating expenses and EBIT information for each of our segments are contained in the following tables for the years ended December 31, 2007, 2006 and 2005.

In millions	Operating revenues	Operating margin (1)	Operating expenses	EBIT (1)
2007				
Distribution operations	$1,665	$820	$485	$338
Retail energy operations	892	188	75	83
Wholesale services	83	77	43	34
Energy investments	42	40	25	15
Corporate (2)	(188)	-	8	(7)
Consolidated	$2,494	$1,125	$636	$463
2006				
Distribution operations	$1,624	$807	$499	$310
Retail energy operations	930	156	68	63
Wholesale services	182	139	49	90
Energy investments	41	36	26	10
Corporate (2)	(156)	1	9	(9)
Consolidated	$2,621	$1,139	$651	$464
2005				
Distribution operations	$1,753	$814	$518	$299
Retail energy operations	996	146	61	63
Wholesale services	95	92	42	49
Energy investments	56	40	23	19
Corporate (2)	(182)	-	6	(11)
Consolidated	$2,718	$1,092	$650	$419

(1) These are non-GAAP measurements. A reconciliation of operating margin and EBIT to our operating income and net income is contained in "Results of Operations" herein.
(2) Includes intercompany eliminations

2007 compared to 2006

In 2007 our net income decreased by $1 million primarily due to decreased EBIT from wholesale services largely due to lower operating margin. This was offset by increased EBIT at distribution operations, retail energy operations and energy investments due to higher operating margins as compared to 2006. Additionally, distribution operations' EBIT contribution increased due to lower operating expenses as compared to 2006. Our basic earnings per share increased by $0.01, primarily due to the reduction in the average number of shares outstanding as a result of our share repurchase program. Our diluted earnings per share were flat.

Operating margin Our operating margin in 2007, decreased $14 million or 1% primarily due to lower operating margin at our wholesale services segment.

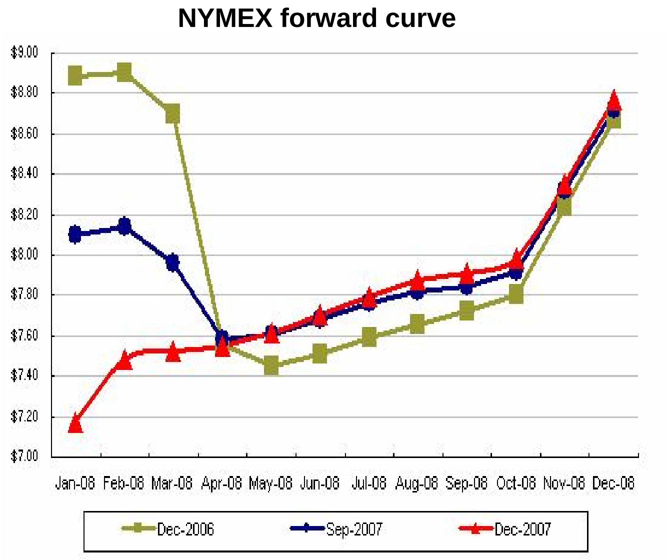
Distribution operations' operating margin increased $13 million or 2% primarily due to a 21,000 or .9% increase in customers as compared to last year, a $2 million increase in base rates at Chattanooga Gas (effective January 1, 2007) and a $2 million increase in PRP operating revenues. Distribution operations' operating margin was further increased by slightly overall higher customer usage of 3 Bcf or 1%. However, our customer usage was impacted by weather that, while colder than last year in some of our jurisdictions, was warmer than normal. Our WNA mechanisms in place to mitigate the loss of operating margin due to weather that was still warmer than normal did not fully offset such losses, resulting in a $9 million decrease in operating margin.

Retail energy operations' operating margin increased $32 million or 21%. This was primarily due to an $8 million increase in average customer usage in Georgia, a $2 million increase from the addition of approximately 7,000 or 1.3% customers, $3 million from the advancement into the Ohio market and $2 million in higher late payment fees. Retail energy operations' operating margin was further positively impacted by the combination of retail price spreads and contributions from the optimization of storage and transportation assets and commodity risk management activities, as well as from a prior year LOCOM adjustment of $6 million to reduce weighted average inventory cost to market. Retail energy operations did not record a similar LOCOM adjustment in 2007 resulting in an increase in operating margin as compared to last year. Even though weather was 4% warmer than last year, retail energy operations' use of weather derivatives largely offset the $2 million decline in operating margin due to warmer weather.

Wholesale services' operating margin decreased $62 million or 45%. This decrease is due to a $36 million reduction in reported hedge gains and a $46 million reduction in commercial activity, due in part to reduced inventory storage spreads and lower volatility in the marketplace. These decreases were partially offset by a $20 million reduction in the required LOCOM adjustments to natural gas inventories for the year ended December 31, 2007, net of $3 million and $22 million in estimated hedging recoveries during 2007 and 2006, respectively. These are indicated in the following table.

In millions	2007	2006	2005
Gain (loss) on storage hedges	$12	$41	$(7)
Gain on transportation hedges	5	12	-
Commercial activity	61	107	102
Inventory LOCOM, net of hedging recoveries	(1)	(21)	(3)
Operating margin	$77	$139	$92

The following graph presents the NYMEX forward natural gas prices as of December 31, 2007, September 30, 2007 and December 31, 2006, for the period of January 2008 through December 2008, and reflects the prices at which wholesale services could buy natural gas at the Henry Hub for delivery in the same time period.



Wholesale services' expected natural gas withdrawals from physical salt dome and reservoir storage are presented in the following table along with the operating revenues expected at the time of withdrawal. Wholesale services' expected operating revenues are net of the impact of regulatory sharing and reflect the amounts that it would expect to realize in future periods based on the inventory withdrawal schedule and forward natural gas prices at December 31, 2007. Wholesale services' storage inventory is economically hedged with futures contracts, which results in an overall locked-in margin, timing notwithstanding. Wholesale services' physical salt dome and reservoir volumes are presented in NYMEX equivalent contract units of 10,000 million British thermal units (MMBtu's).

	Three months ended			
	Mar. 31, 2008	June 30, 2008	Dec.31, 2008	Total
Salt dome (WACOG $6.70)	33	-	94	127
Reservoir (WACOG $6.20)	773	24	-	797
Total volumes	806	24	94	924
Expected operating revenues from physical inventory *(in millions)*	$9	$-	$2	$11

Energy investments' operating margin increased $4 million or 11% primarily due to a $2 million increase in revenues at Jefferson Island as a result of increased interruptible margin opportunities and a $2 million increase at AGL Networks as a result of a larger customer base.

Operating expenses Our operating expenses in 2007 decreased $15 million or 2% from 2006. The following table indicates the significant changes in our operating expenses.

In millions	
Operating expenses for year ended Dec. 31, 2006	$651
Decreased incentive compensation costs at distribution operations due to not achieving AIP earnings goals	(14)
Decreased incentive compensation costs at wholesale services due to lower operating margin	(13)
Decreased bad debt expense at retail energy operations	(3)
Increased incentive compensation costs due to growth and improved operations at retail energy operations	3
Increased depreciation and amortization	6
Increased payroll and other operating costs at wholesale services due to continued expansion	7
Increased costs at retail energy operations due to customer care, marketing costs and higher payroll in support of customer and market growth initiatives	5
Other, net primarily at distribution operations due to pension, outside services and reduction in customer service expense	(6)
Operating expenses for year ended Dec. 31, 2007	$636

Our other income increased by $5 million. This was primarily due to lower charitable contributions in 2007 at distribution operations and retail energy operations.

Interest expense The increased interest expense of $2 million or 2% in 2007 was due primarily to higher short-term interest rates and a $3 million premium paid for the early redemption of the $75 million notes payable to AGL Capital Trust I, which was recorded as interest expense in 2007. As indicated in the following table, this was partially offset by lower average debt, primarily from reduced commercial paper borrowings for most of 2007.

In millions	2007	2006	Change
Interest expense	$125	$123	$2
Average debt outstanding (1)	$1,967	$2,023	$(56)
Average rate (2)	6.4%	6.1%	0.3%

(1) Daily average of all outstanding debt.
(2) Excluding $3 million premium paid for early redemption of debt, average rate in 2007 would have been 6.2%.

Income tax expense The decrease in income tax expense of $2 million or 2% in 2007, compared to the same period in 2006 was primarily due to lower consolidated earnings and a slightly lower effective tax rate of 37.6% in 2007 compared to an effective tax rate of 37.8% in 2006. The decrease in our effective tax rate was primarily a result of our 2007 investment in a guaranteed affordable housing tax credit fund. We expect our effective tax rate in 2008 to remain consistent with our 2007 rate. For more information on our income taxes, including a reconciliation between the statutory federal income tax rate and the effective rate, see Note 8.

2006 compared to 2005

In 2006 our net income increased by $19 million or 10%, our basic earnings per share increased by $0.23 or 9% and our diluted earnings per share increased by $0.24. This was primarily due to increased EBIT of $41 million in wholesale services which primarily reflected the recognition of unrealized hedge gains during 2006, as forward NYMEX prices declined significantly. In contrast, NYMEX price increases experienced during 2005 had the opposite effect, but to a lesser extent. In the distribution operations segment, EBIT improved by $11 million, due to reduced operating expenses of $19 million, offset by lower operating margin of $7 million. Our retail energy operations segment's EBIT was flat compared to 2005. The energy investments segment's EBIT was down $9 million primarily due to the loss of EBIT contributions as the result of the sale in 2005 of certain assets that were originally acquired with the 2004 acquisition of NUI.

Operating margin Our operating margin increased $47 million or 4% from 2005. This was primarily due to increases at wholesale services and retail energy operations offset by declines at distribution operations.

Wholesale services increased its operating margin $47 million or 51% as compared to 2005 due to significant arbitrage opportunities brought on by natural gas price volatility and periods of extreme weather. Forward NYMEX prices decreased during 2006, especially during the third and fourth quarters, and this resulted in the wholesale services segment recognizing $41 million of storage hedge gains in 2006, compared to the recognition of $7 million of storage hedge losses in 2005. In addition, wholesale services recognized $12 million in gains associated with the financial instruments used to hedge its transportation capacity. There were no significant gains or losses associated with transportation hedges recognized in the prior period. Consequently, wholesale services experienced a net change of $60 million from its hedging activities for 2006 compared to 2005.

In addition, as a result of decreasing NYMEX prices the wholesale services segment evaluated the weighted average cost of its natural gas inventory and recorded LOCOM adjustments totaling $43 million in 2006; however, as inventory was physically withdrawn from storage during the year, $22 million of the 2006 adjustments were recovered and reflected in 2006 operating revenues when the original economic results were realized as the related hedging derivatives were settled. In 2005, wholesale services recorded LOCOM adjustments of $3 million.

The results of the wholesale services segment also reflect improved commercial activities of approximately $5 million associated with larger seasonal storage spreads during the first half of 2006 and above average temperatures during the late summer months. These conditions offset the impacts of mild weather during the winter and early summer and the lower level of market volatility that we experienced compared to the hurricane activity in the Gulf of Mexico in 2005.

Retail energy operation's operating margin increased by $10 million or 7% principally driven by improved retail price spreads, higher contributions from the optimization of storage and transportation assets and effective risk management, and an increase of approximately 2,000 average customers in 2006 as compared to 2005. These factors contributed $34 million in operating margin contributions, but was offset by $16 million in lower operating margin from customer conservation and lower consumption due to weather that was approximately 10% warmer than 2005, net of $5 million in net gains on weather derivatives. Operating margin was further negatively impacted by an adjustment in 2006 of $6 million to reduce inventory to market for which no LOCOM adjustment was recorded in 2005, and from $2 million in lower late payment fees and interruptible operating margin contributions.

Operating margin for the distribution operations segment decreased $7 million or 1% primarily from warmer weather affecting customer usage and from our exiting the New Jersey and Florida appliance businesses. The operating margin at Elizabethtown Gas decreased $3 million with 17% warmer weather than in 2005. Virginia Natural Gas' operating margin decreased $4 million with 17% warmer weather, and the operating margin at Florida City Gas decreased $2 million with 15% warmer weather. Further, our exiting of the New Jersey and Florida appliance businesses reduced operating margin by $3 million. This reduction was partially offset by a net increase in operating margin at Atlanta Gas Light of $6 million consisting of $5 million in gas storage carrying costs from higher average inventory balances and $2 million in PRP revenues from the continuing expenditures under the program, offset primarily by $2 million as a result of the effect of the Georgia Commission's June 2005 Rate Order.

Operating margin at energy investments decreased $4 million or 10% largely due to the loss of $9 million of operating margin contributions from certain assets we acquired with the 2004 acquisition of NUI but sold in 2005. Jefferson Island's operating margin increased by $1 million compared to the prior year, in part due to increases in both firm and interruptible operating margin opportunities. AGL Networks' operating margin increased by $1 million compared to the prior year due to a larger customer base. Pivotal Propane contributed a $2 million increase primarily in the first quarter of 2006 as it did not become operational until April 2005.

Operating expenses Our operating expenses increased $1 million or 0.2% from the same period in 2005. The following table sets forth the significant components of operating expenses:

In millions	
Operating expenses for 2005	$650
Increased payroll, incentive compensation and corporate overhead allocated costs at wholesale services to support growth	7
Increased bad debt expenses at retail energy operations and distribution operations	4
Lower expenses resulting from energy investment assets sold in 2005	(8)
Lower expenses at distribution operations related to workforce and facilities restructurings in 2005 and 2006	(15)
Increased depreciation and amortization	5
Other	8
Operating expenses for 2006	$651

Interest expense Interest expense for 2006 increased by $14 million or 13% as compared to 2005. As indicated in the following table, higher short-term interest rates and higher debt outstanding combined to increase our interest expense in 2006 relative to the previous year. The increase of $200 million in average debt outstanding for 2006 compared to 2005 was due to additional debt incurred as a result of higher working capital requirements.

In millions	**2006**	**2005**	**Change**
Total interest expense	$123	$109	$14
Average debt outstanding (1)	2,023	1,823	200
Average interest rate	6.1%	6.0%	0.1%

(1) Daily average of all outstanding debt.

Income tax expense The increase in income tax expense of $12 million or 10% for 2006 compared to 2005 reflected additional income taxes primarily due to higher corporate earnings year over year.

Liquidity and Capital Resources

Our primary sources of liquidity are cash provided by operating activities, short term borrowings under our commercial paper program (which is supported by our Credit Facility) and borrowings under lines of credit. Additionally from time to time, we raise funds from the public debt and equity capital markets through our existing shelf registration statement to fund our liquidity and capital resource needs. We believe these sources will continue to allow us to meet our needs for working capital, construction expenditures, anticipated debt redemptions, interest payments on debt obligations, dividend payments, common share repurchases and other cash needs.

Our issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by state and federal regulatory bodies including state public service commissions and the SEC. Furthermore, a substantial portion of our consolidated assets, earnings and cash flow is derived from the operation of our regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to us is subject to regulation.

We will continue to evaluate our need to increase available liquidity based on our view of working capital requirements, including the impact of changes in natural gas prices, liquidity requirements established by rating agencies and other factors. See Item 1A, "Risk Factors," for additional information on items that could impact our liquidity and capital resource requirements. The following table provides a summary of our operating, investing and financing activities for the last three years.

In millions	2007	2006	2005
Net cash provided by (used in):			
Operating activities	$376	$354	$80
Investing activities	(253)	(248)	(194)
Financing activities	(122)	(118)	97
Net increase (decrease) in cash and cash equivalents	$1	$(12)	$(17)

Cash Flow from Operating Activities We prepare our statement of cash flows using the indirect method. Under this method, we reconcile net income to cash flows from operating activities by adjusting net income for those items that impact net income but may not result in actual cash receipts or payments during the period. These reconciling items include depreciation and amortization, changes in risk management assets and liabilities, undistributed earnings from equity investments, deferred income taxes and changes in the consolidated balance sheet for working capital from the beginning to the end of the period.

Our operations are seasonal in nature, with the business depending to a great extent on the first and fourth quarters of each year. As a result of this seasonality, our natural gas inventories, which usually peak on November 1 and largely are drawn down in the heating season, provide a source of cash as this asset is used to satisfy winter sales demand. The establishment and price fluctuations of our natural gas inventories which meet customer demand during the winter heating season can cause significant variations in our cash flow from operations from period to period and are reflected in changes to our working capital.

Year-over-year changes in our operating cash flows are attributable primarily to working capital changes within our distribution operations, retail energy operations and wholesale services segments resulting from the impact of weather, the price of natural gas, the timing of customer collections, payments for natural gas purchases and deferred gas cost recoveries as our business has grown and prices for natural gas have increased. The increase in natural gas prices directly impacts the cost of gas stored in inventory.

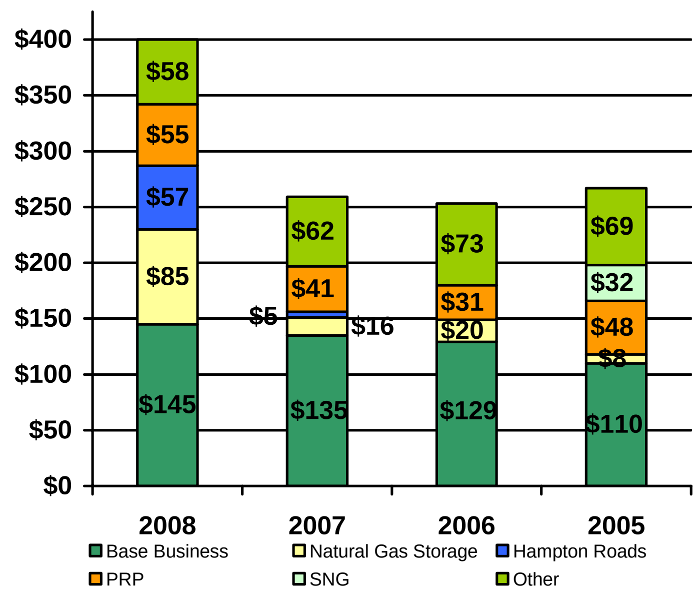
2007 compared to 2006 In 2007, our net cash flow provided from operating activities was $376 million, an increase of $22 million or 6% from 2006. The increase was due to higher realized gains on our energy marketing and risk management assets and liabilities and lower cash requirements for our natural gas inventories due to price and inventory volume fluctuations. This was offset by increased cash payments for income taxes due to realized gains on our energy marketing and risk management activities and higher working capital requirements.

2006 compared to 2005 In 2006, our net cash flow provided from operating activities was $354 million, an increase of $274 million or 343% from 2005. The increase was primarily a result of higher earnings in 2006 of $19 million and the recovery of working capital during 2006 that was deployed in late 2005 due to higher natural gas commodity prices and colder weather in the 2005 heating season. A primary contributor to the recovery of working capital was a $157 million decrease in the amount of natural gas inventory purchases by Sequent and our utilities.

Cash Flow from Investing Activities Our investing activities consisted primarily of property, plant and equipment (PP&E) expenditures. The majority of our PP&E expenditures are within our distribution operations segment, which includes our investments in new construction and infrastructure improvements.

Our estimated PP&E expenditures of approximately $400 million in 2008 and actual PP&E expenditures of $259 million in 2007, $253 million in 2006 and $267 million in 2005 are presented in the following chart. Our estimated expenditures in 2008 include discretionary spending for capital projects principally within the base business and natural gas storage categories. In determining whether to proceed with these projects, we evaluate such discretionary capital projects in relation to a number of factors including our authorized returns on rate base, other returns on invested capital for projects of a similar nature, capital structure and credit ratings, among others. As such, we will make adjustments to these discretionary expenditures as necessary based upon these factors. Our estimated and actual PP&E expenditures are shown within the following categories.

- **Base business** – new construction and infrastructure improvements at our distribution operations segment
- **Natural gas storage** – salt-dome cavern expansions at Golden Triangle and Jefferson Island
- **Hampton Roads** – Virginia Natural Gas' pipeline project, which will connect its northern and southern systems
- **PRP** – Atlanta Gas Light's program to replace all bare steel and cast iron pipe in its system in Georgia
- **SNG** – a 250-mile pipeline in Georgia acquired from Southern Natural Gas (SNG) in 2005
- **Other** – primarily includes information technology, building and leasehold improvements and AGL Networks' telecommunication expenditures



In 2007, our PP&E expenditures were $6 million or 2% higher than in 2006. This was primarily due to an increase in PRP expenditures of $10 million as we replaced larger-diameter pipe in more densely populated areas and $5 million in expenditures for the Hampton Roads project. This was offset by decreased expenditures of $4 million on our storage projects.

The decrease of $14 million or 5% in PP&E expenditures in 2006 compared to 2005 was primarily due to the SNG pipeline acquisition of $32 million, which occurred in 2005, and $17 million in reduced PRP expenditures, primarily as a result of the June 2005 agreement with the Georgia Commission, which extended the PRP program by five years. This was offset by increased base business expenditures of $19 million, primarily as our utilities expanded their new construction investments. We also incurred higher information technology expenditures of $13 million, which included $5 million at retail energy operations, primarily due to the implementation of a new energy trading and risk management system and enhancements to the retail billing system. Additionally in 2006, we spent $12 million in additional PP&E expenditures at Jefferson Island as it began work on a salt-dome storage expansion project which would add a third and fourth storage cavern. In 2005, our cash flows from investing activities were positively impacted as we sold our 50% interest in Saltville Gas Storage Company (Saltville) and associated subsidiaries for $66 million to a subsidiary of Duke Energy Corporation. We acquired Saltville through our acquisition of NUI in 2004.

Cash Flow from Financing Activities Our financing activities are primarily composed of borrowings and payments of short-term debt, payments of medium-term notes, and notes payable to AGL Capital Trust I and II, borrowings of senior notes, distributions to minority interests, cash dividends on our common stock issuances, purchases and issuances of treasury shares and the use of interest rate swaps for the purpose of hedging interest rate risk. 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 of the percentage of total debt relative to total capitalization, appropriate mix of debt with fixed to floating interest rates (our variable debt target is 20% to 45% of total debt), as well as the term and interest rate profile of our debt securities.

As of December 31, 2007, our variable rate debt was $840 million or 37% of our total debt, compared to $733 million or 34% as of December 31, 2006. The increased variable-rate debt was principally due to higher commercial paper borrowings. As of December 31, 2007, our commercial paper borrowings were $58 million or 11% higher than the same time last year, primarily a result of a $42 million increase in common share repurchases in 2007 and slightly higher working capital needs. For more information on our debt, see Note 6.

Credit Ratings We also work to maintain or improve our credit ratings on our debt to 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 agreements that would require us to issue equity based on credit ratings or other trigger events.

Improvements in our operating performance led to our credit outlook being raised from negative to stable by S&P in late 2007. The following table summarizes our credit ratings as of December 31, 2007.

	S&P	Moody's	Fitch
Corporate rating	A-		
Commercial paper	A-2	P-2	F-2
Senior unsecured	BBB+	Baa1	A-
Ratings outlook	Stable	Stable	Stable

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.

Default Events 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 a maximum leverage ratio, insolvency events, nonpayment of scheduled principal or interest payments, and acceleration of other financial obligations and change of control provisions.

Our Credit Facility's financial covenant requires 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%. We are currently in compliance with all existing debt provisions and covenants. We believe that accomplishing these capitalization objectives and maintaining sufficient cash flow are necessary to maintain our investment-grade credit ratings and to allow us access to capital at reasonable costs. The components of our capital structure, as of the dates indicated, are summarized in the following table.

In millions	Dec. 31, 2007		Dec. 31, 2006	
Short-term debt	$580	15%	$539	14%
Long-term debt (1)	1,674	43	1,622	43
Total debt	2,254	58	2,161	57
Common shareholders' equity	1,661	42	1,609	43
Total capitalization	$3,915	100%	$3,770	100%

(1) Net of interest rate swaps.

Short-term Debt Our short-term debt is composed of borrowings under our commercial paper program, lines of credit at Sequent, SouthStar and Pivotal Utility, the current portion of our medium-term notes (for 2006) and the current portion of our capital leases. 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. 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 June and August 2007 we extended Sequent's $45 million unsecured lines of credit through June ($25 million) and August ($20 million) 2008. Sequent's lines of credit are used solely for the posting of margin deposits for NYMEX transactions. In August 2007, we extended Pivotal Utility's $20 million unsecured line of credit through August 2008. This line of credit supports Elizabethtown Gas' New Jersey Commission mandated hedging program and is used solely for the posting of margin deposits. These lines of credit bear interest at the federal funds effective rate plus 0.4% and are unconditionally guaranteed by us.

Under the terms of our Credit Facility, which expires in August 2011, the aggregate principal amount available is $1 billion and we can request an option to increase the aggregate principal amount available for borrowing to $1.25 billion on not more than three occasions during each calendar year.

As of December 31, 2007 and 2006, we had no outstanding borrowings under the Credit Facility. However, the availability of borrowings and unused credit under our Credit Facility is limited and subject to conditions specified within the Credit Facility, which we currently meet. These conditions include:

- the maintenance of a ratio of total debt to total capitalization of no greater than 70%. As of December 31, 2007, our ratio of total debt of 58% to total capitalization was within our targeted and required ranges, and was consistent with our ratio of 57% at December 31, 2006
- the continued accuracy of representations and warranties contained in the agreement

Long-term Debt Our long-term debt matures more than one year from the balance sheet date and consists of medium-term notes, senior notes, gas facility revenue bonds, and capital leases. The following represents our long-term debt activity in 2007.

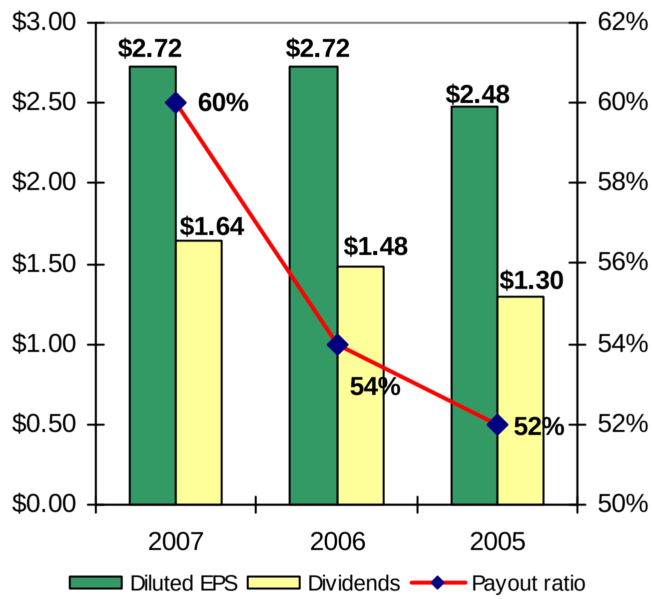
- In January 2007, we used proceeds from the sale of commercial paper to redeem $11 million of 7% medium-term notes previously scheduled to mature in January 2015.
- In June 2007 we refinanced $55 million of our gas facility revenue bonds due June 2032.The original bonds had a fixed interest rate of 5.7% per year and were refinanced with $55 million of adjustable-rate gas facility revenue bonds. The maturity date of these bonds remains June 2032 and there is a 35-day auction period where the interest rate adjusts every 35 days. The interest rate at December 31, 2007, was 4.7%.
- In July 2007, we used the proceeds from the sale of commercial paper to pay to AGL Capital Trust I the $75 million principal amount of 8.17% junior subordinated debentures plus a $3 million premium for early redemption of the junior subordinated debentures, and to pay a $2 million note representing our common securities interest in AGL Capital Trust I.
- In December 2007, AGL Capital issued $125 million of 6.375% senior notes. The senior notes are part of a series of notes issued by AGL Capital in June 2006. Both sets of notes are now part of a single series with an aggregate of $300 million in principal outstanding. The proceeds of the note issuance, equal to approximately $123 million, were used to pay down short-term indebtedness incurred under our commercial paper program.

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 in our consolidated balance sheets. A cash distribution of $23 million in 2007, $22 million in 2006 and $19 million in 2005 for SouthStar's dividend distributions to Piedmont were recorded in our consolidated statement of cash flows as a financing activity.

Dividends on Common Stock Our $12 million or 11% increase in common stock dividend payments in

2007 compared to 2006, and $11 million or 11% increase in payments in 2006 compared to 2005, resulted from increases in the amount of our quarterly common stock dividends per share.

In 2007, our dividend payout ratio was 60%. This is an increase of 11% from our payout ratio of 54% in 2006. We expect that our dividend payout ratio will remain consistent with the dividend payout ratios of our peer companies, which is currently in a range of 60% to 65%. Our diluted earnings per share and dividends declared per share along with our payout ratio for the last three years are presented in the following chart.



For information about restrictions on our ability to pay dividends on our common stock, see Note 5 "Common Shareholders' Equity".

Share Repurchases In March 2001 our Board of Directors approved the purchase of up to 600,000 shares of our common stock to be used for issuances under the Officer Incentive Plan. During 2007, we purchased 10,667 shares. As of December 31, 2007, we had purchased a total 297,234 shares, leaving 302,766 shares available for purchase.

In February 2006, our Board of Directors authorized a plan to purchase up to 8 million shares of our outstanding common stock over a five-year period. These purchases are intended principally to offset share issuances under our employee and non-employee director incentive compensation plans and our dividend reinvestment and stock purchase plans. Stock purchases under this program may be made in the open market or in private transactions at times and in amounts that we deem appropriate. There is no guarantee as to the exact number of shares that we will purchase, and we can terminate or limit the program at any time.

For the year ended December 31, 2007, we purchased approximately 2 million shares of our common stock at an average cost of $39.56 per share and an aggregate cost of $80 million. During the same period in 2006, we purchased approximately 1 million shares of our common stock at a weighted average cost of $36.67 per share and an aggregate cost of $38 million. This represented an increase of $42 million or 111% from last year. We hold the purchased shares as treasury shares. For more information on our share repurchases see Item 5 "Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities."

Shelf Registration In August 2007, we filed a new shelf registration with the SEC. The debt securities and related guarantees will be issued by AGL Capital under an indenture dated as of February 20, 2001, as supplemented and modified, as necessary, among AGL Capital, AGL Resources and The Bank of New York Trust Company, N.A., as trustee. The indenture provides for the issuance from time to time of debt securities in an unlimited dollar amount and an unlimited number of series subject to our Credit Facility's financial covenants related to total debt to total capitalization. The debt securities will be guaranteed by AGL Resources. This replaces the previous shelf registration, filed in October 2004, which had $782 million available to be issued.

Contractual Obligations and Commitments We have incurred various contractual obligations and financial commitments in the normal course of our operating and financing activities that are reasonably likely to have a material effect on liquidity or the availability of requirements for capital resources. 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. The following table illustrates our expected future contractual obligation payments such as debt and lease agreements, and commitments and contingencies as of December 31, 2007.

In millions	Total	2008	2009 & 2010	2011 & 2012	2013 & thereafter
Recorded contractual obligations:					
Long-term debt	$1,674	$-	$2	$315	$1,357
Short-term debt	580	580	-	-	-
ERC (1)	107	10	34	53	10
PRP costs (1)	245	55	112	60	18
Total	$2,606	$645	$148	$428	$1,385

(1) Includes charges recoverable through rate rider mechanisms.

In millions	Total	2008	2009 & 2010	2011 & 2012	2013 & thereafter
Unrecorded contractual obligations and commitments (1)**:**					
Interest charges (2)	$1,176	$100	$200	$157	$719
Pipeline charges, storage capacity and gas supply (3)	1,792	456	637	348	351
Operating leases	154	26	50	34	44
Standby letters of credit, performance / surety bonds	30	24	6	-	-
Asset management agreements (4)	24	8	8	8	-
Total	$3,176	$614	$901	$547	$1,114

(1) In accordance with generally accepted accounting principles, these items are not reflected in our consolidated balance sheet.
(2) Floating rate debt is based on the interest rate as of December 31, 2007 and the maturity of the underlying debt instrument. As of December 31, 2007 we have $39 million of accrued interest on our consolidated balance sheet that will be paid in 2008.
(3) Charges recoverable through a PGA mechanism or alternatively billed to Marketers. Also includes demand charges associated with Sequent.
(4) Represent fixed-fee payments for Sequent's asset management agreements between Atlanta Gas Light ($4 million) and Elizabethtown Gas ($4 million). As of December 31, 2007, we have $1 million of fixed-fee payments are accrued on our consolidated balance sheet, which will be paid in 2008.

Pipeline Charges, Storage Capacity and Gas Supply Contracts. A subsidiary of NUI entered into two 20-year agreements for the firm transportation and storage of natural gas during 2003 with annual aggregate demand charges of approximately $5 million. As a result of our acquisition of NUI and accordance with SFAS 141, we valued the contracts at fair value and established a long-term liability for the excess liability that will be amortized over the remaining lives of the contracts. The gas supply amount includes SouthStar gas commodity purchase commitments of 1.3 Bcf at floating gas prices calculated using forward natural gas prices as of December 31, 2007, and is valued at $98 million.

Operating leases. We have certain operating leases with provisions for step rent or escalation payments and certain lease concessions. We account for these leases by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms, in accordance with SFAS 13. However, this accounting treatment does not affect the future annual operating lease cash obligations as shown herein. We expect to fund these obligations with cash flow from operating and financing activities.

Standby letters of credit and surety bonds. 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. We would expect to fund these contingent financial commitments with operating and financing cash flows.

Pension and Postretirement Obligations We calculate any required pension contributions using the projected unit credit cost method. Under this method, we were not required to and did not make any pension contribution during 2007. During 2006, we voluntarily contributed $5 million to the AGL Resources Inc. Retirement Plan.

The state regulatory commissions have phase-ins that defer a portion of the postretirement benefit expense for future recovery. We recorded a regulatory asset for these future recoveries of $12 million as of December 31, 2007 and $13 million as of December 31, 2006. In addition, we recorded a regulatory liability of $4 million as of December 31, 2007 and $4 million as of December 31, 2006 for our expected expenses under the AGL Postretirement

Plan. See Note 3 “Employee Benefit Plans,” for additional information about our pension and postretirement plans.

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, and we evaluate our estimates on an ongoing basis. Our actual results may differ from our 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.

Pipeline Replacement Program Liabilities Atlanta Gas Light was ordered by the Georgia Commission (through a joint stipulation and a subsequent settlement agreement between Atlanta Gas Light and the Commission staff) to undertake a PRP that would replace all bare steel and cast iron pipe in its system. Approximately 103 miles of cast iron and 533 miles of bare steel pipe still require replacement. If Atlanta Gas Light does not perform in accordance with the initial and amended PRP stipulation, it can be assessed certain nonperformance penalties. However to date, Atlanta Gas Light is in full compliance.

The stipulation also provides for recovery of all prudent costs incurred under 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 associated with our PRP involves judgment. Factors that must be considered in estimating the future expected costs are projected capital expenditure spending, including labor and material costs, and the remaining infrastructure footage to be replaced for the remaining years of the program. We recorded a long-term liability of $190 million as of December 31, 2007 and $202 million as of December 31, 2006, which represented engineering estimates for remaining capital expenditure costs in the PRP. As of December 31, 2007, we had recorded a current liability of $55 million, representing expected PRP expenditures for the next 12 months. We report these estimates on an undiscounted basis. If Atlanta Gas Light’s PRP expenditures, subject to future recovery, were $10 million higher or lower its incremental expected annual revenues would have changed by approximately $1 million.

Environmental Remediation Liabilities We 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, we are increasingly able to provide conventional engineering estimates of the likely costs of many elements of the remediation program. These estimates contain various engineering uncertainties, and we continuously attempt to refine and update these engineering estimates.

Our latest available estimate as of December 31, 2007 for those elements of the remediation program with in-place contracts or engineering cost estimates is $15 million for Atlanta Gas Light’s Georgia and Florida sites. This is an increase of $2 million from the December 31, 2006 estimate of projected engineering and in-place contracts, resulting from increased cost estimates during 2007. 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 $20 million, which includes approximately $1 million in estimates of certain other costs it pays related to administering the remediation program and remediation of sites currently in the investigation phase. Beyond 2009, these costs cannot be estimated. As of December 31, 2007, we have recorded a liability of $35 million.

Atlanta Gas Light’s environmental remediation liability is included in its corresponding regulatory asset. 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 recovery of environmental remediation costs is subject to review by the Georgia Commission, which may seek to disallow the recovery of some expenses.

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 $61 million to $119 million. As of December 31, 2007, we have recorded a liability of $61 million.

The New Jersey Commission has authorized Elizabethtown Gas to recover prudently incurred remediation costs for the New Jersey properties through its remediation adjustment clause. As a result, Elizabethtown Gas has recorded a regulatory asset of approximately $66 million, inclusive of interest, as of December 31, 2007, 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, 2007, the variation between the amounts of the environmental remediation cost liability recorded in 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 Environment and Natural Resources. Preliminary estimates for investigation and remediation costs range from $11 million to $20 million. As of December 31, 2007, we had recorded a liability of $11 million related to this site. There is one other 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 manage our remediation costs so as to mitigate the impact of such costs on both ratepayers and shareholders.

Derivatives and Hedging Activities SFAS 133, as updated by 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 OCI until maturity in the case of a cash flow hedge. Additionally, SFAS 133 requires that a company formally designate a derivative as a hedge as well as document and assess the effectiveness of derivatives associated with transactions that receive hedge accounting treatment. SFAS 133 applies to treasury locks and interest rate swaps executed by AGL Capital and gas commodity contracts executed by Sequent and SouthStar. SFAS 133 also applies to gas commodity contracts executed by Elizabethtown Gas under a New Jersey Commission authorized hedging program that requires gains and losses on these derivatives are reflected in purchased gas costs and ultimately billed to customers. Our derivative and hedging activities are described in further detail in Note 2 "Financial Instruments and Risk Management" and Item 1 "Business."

Commodity-related Derivative Instruments We are exposed to risks associated with changes in the market price of natural gas. Through Sequent and SouthStar, we use derivative instruments to reduce our exposure impact to our results of operations due to the risk of changes in the price of natural gas.

Sequent recognizes the change in value of a derivative instrument as an unrealized gain or loss in revenues in the period when the market value of the instrument changes. Sequent recognizes cash inflows and outflows associated with the settlement of its risk management activities in operating cash flows, and reports these settlements as receivables and payables in the balance sheet separately from the risk management activities reported as energy marketing receivables and trade payables.

We attempt to mitigate substantially all our commodity price risk associated with Sequent's natural gas storage portfolio and lock in the economic margin at the time we enter into purchase transactions for our stored natural gas. We purchase natural gas for storage when the current market price we pay plus storage costs is less than the market price we could receive in the future. We lock in the economic margin by selling NYMEX futures contracts or other over-the-counter derivatives in the forward months corresponding with our withdrawal periods. We use contracts to sell natural gas at that future price to lock in the operating margin we will ultimately realize when the stored natural 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. That difference in accounting can result in volatility in our reported operating margin, even though the economic margin is essentially unchanged from the date we entered into the transactions. We do not currently use hedge accounting under SFAS 133 to account for this activity.

Natural gas that we purchase and inject into storage is accounted for at the lower of average cost or market value. Under current accounting guidance, we recognize a loss in any period when the market price for natural gas is lower than the carrying amount of our purchased natural gas inventory. Costs to store the natural gas are recognized in the period the costs are incurred. We recognize revenues and cost of natural 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 operating margin upon the sale of stored natural 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 lower of average cost or market basis for our storage inventory versus the fair value accounting for the derivatives used to mitigate commodity price risk - can and does result in volatility in our reported earnings.

Over time, gains or losses on the sale of storage inventory will be substantially offset by losses or gains on the derivatives, resulting in realization of the economic profit margin we expected when we entered into the transactions. This accounting difference causes Sequent's earnings on its storage positions to be affected by natural gas price changes, even though the economic profits remain essentially unchanged.

SouthStar also uses derivative instruments to manage exposures arising from changing commodity prices. SouthStar's objective for holding these derivatives is to minimize volatility in wholesale commodity natural gas prices. A 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 the underlying hedged item is reflected in the income statement. As of December 31, 2007, the ending balance in OCI for derivative transactions designated as cash flow hedges under SFAS 133 was a gain of $3 million, net of minority interest and taxes. Any hedge ineffectiveness, defined as when the gains or losses on the hedging instrument do not 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 are not designated as hedges under SFAS 133. Therefore, changes in their fair value are recorded in earnings in the period of change.

SouthStar also enters into weather derivative instruments in order to preserve operating margins in the event of warmer-than-normal weather in the winter months. These contracts are accounted for using the intrinsic value method under the guidance of EITF 99-02. Changes in the fair value of these derivatives are recorded in earnings in the period of change. The weather derivative contracts contain strike amount provisions based on cumulative heating degree days for the covered periods. In 2007 and 2006, SouthStar entered into weather derivatives (swaps and options) for the respective winter heating seasons, primarily from November through March. As of December 31, 2007, SouthStar recorded a current asset of $5 million for this hedging activity.

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 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.

Pension and Other Postretirement Plans Our pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and current demographic and actuarial mortality data. We annually review the estimates and assumptions underlying our pension and other postretirement plan costs and liabilities. The assumed discount rate and the expected return on plan assets are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rate, the assumed health care cost trend rate and the assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

The discount rate is used principally to calculate the actuarial present value of our pension and postretirement obligations and net pension and postretirement cost. When establishing our discount rate which we have determined to be 6.4% at December 31, 2007, we consider high quality corporate bond rates based on Moody’s Corporate AA long-term bond rate of 5.9% and the Citigroup Pension Liability rate of 6.5% at December 31, 2007. We further use these market indices as a comparison to a single equivalent discount rate derived with the assistance of our actuarial advisors. This analysis as of December 31, 2007 produced a single equivalent discount rate of 6.5%.

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.

The expected long-term rate of return on assets is used to calculate the expected return on plan assets component of our annual pension and postretirement plan cost. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider guidance from our investment advisors in making a final determination of our expected rate of return on assets. To the extent the actual rate of return on assets realized over the course of a year is greater than or less than the assumed rate, that year’s annual pension or postretirement plan cost is not affected. Rather, this gain or loss reduces or increases future pension or postretirement plan costs.

Prior to 2006, we estimated the assumed health care cost trend rate used in determining our postretirement net expense based on our actual health care cost experience, the effects of recently enacted legislation and general economic conditions. However, starting in 2006, our postretirement plans have been capped at 2.5% for increases in health care costs. Consequently, a one-percentage-point increase or decrease in the assumed health care trend rate does not materially affect the periodic benefit cost for our postretirement plans. A one percentage-point increase in the assumed health care cost trend rate would increase our accumulated projected benefit obligation by $4 million. A one percentage-point decrease in the assumed health care cost trend rate would decrease our accumulated projected benefit obligation by $4 million. Our assumed rate of retirement is estimated based upon an annual review of participant census information as of the measurement date.

At December 31, 2007, our pension and postretirement liability decreased by approximately $45 million, primarily resulting from an after-tax gain to OCI of $24 million ($40 million before tax), $9 million in benefit payments that we funded offset by $4 million in net pension and postretirement benefit costs we recorded in 2007. These changes reflect our funding contributions to the plan, benefit payments out of the plans, and updated valuations for the projected benefit obligation (PBO) and plan assets.

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 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.

See “Note 3, Employee Benefit Plans,” for additional information on our pension and postretirement plans, which includes our investment policies and strategies, target allocation ranges and weighted average asset allocations for 2007 and 2006.

The actual return on our pension plan assets compared to the expected return on plan assets of 9% will have an impact on our ABO as of December 31, 2008 and our pension expense for 2008. We are unable to determine how this actual return on plan assets will affect future ABO 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, 2008. Our actual returns may also be positively or negatively impacted as a result of future performance in the equity and bond markets. The following tables illustrate the effect of changing the critical actuarial assumptions, as discussed previously, while holding all other assumptions constant.

AGL Resources Inc. Retirement and Postretirement Plans

In millions		Pension Benefits		Health and Life Benefits	
Actuarial assumptions	Percentage-point change in assumption	Increase (decrease) in ABO	Increase (decrease) in cost	Increase (decrease) in obligation	Increase (decrease) in cost
Expected long-term return on plan assets	+/- 1%	$- / -	$(3) / 3		
Discount rate	+/- 1%	(40) / 45	(4) / 4		
Healthcare cost trend rate	+/- 1%			$4 / (4)	$- / -

NUI Corporation Retirement Plan

In millions			Pension Benefits
Actuarial assumptions	Percentage-point change in assumption	Increase (decrease) in ABO	Increase (decrease) in cost
Expected long-term return on plan assets	+/- 1%	$- / -	$(1) / 1
Discount rate	+/- 1%	(5) / 5	- / (1)

Differences between actuarial assumptions and actual plan results are deferred and amortized into cost when the accumulated differences exceed 10% of the greater of the PBO or the MRVPA. If necessary, the excess is amortized over the average remaining service period of active employees.

In addition to the assumptions listed above, the measurement of the plans' obligations and costs depend on other factors such as employee demographics, the level of contributions made to the plans, earnings on the plans' assets and mortality rates.

Income Taxes We account for income taxes in accordance with SFAS 109 and FIN 48 which require that deferred tax assets and liabilities be recognized using enacted tax rates for the effect of temporary differences between the book and tax basis of recorded assets and liabilities. SFAS 109 and FIN 48 also requires that deferred tax assets be reduced by a valuation if it is more likely than not that some portion or all of the deferred tax asset will not be realized. We adopted the provisions of FIN 48 on January 1, 2007. At the date of adoption and as of December 31, 2007, we did not have a liability for unrecognized tax benefits.

Our net long-term deferred tax liability totaled $566 million at December 31, 2007 (see Note 8 "Income Taxes"). This liability is estimated based on the expected future tax consequences of items recognized in the financial statements. After application of the federal statutory tax rate to book income, judgment is required with respect to the timing and deductibility of expense in our income tax returns. For state income tax and other taxes, judgment is also required with respect to the apportionment among the various jurisdictions. A valuation allowance is recorded if we expect that it is more likely than not that our deferred tax assets will not be realized. We had a $3 million valuation allowance on $53 million of deferred tax assets as of December 31, 2007, reflecting the expectation that most of these assets will be realized. In addition, we operate within multiple taxing jurisdictions and we are subject to audit in these jurisdictions. These audits can involve complex issues, which may require an extended period of time to resolve. We maintain a liability for the estimate of potential income tax exposure and in our opinion adequate provisions for income taxes have been made for all years.

Accounting Developments

SFAS 157 In September 2006, the FASB issued SFAS 157, which establishes a framework for measuring fair value and requires expanded disclosures regarding fair value measurements. SFAS 157 does not require any new fair value measurements. However, it eliminates inconsistencies in the guidance provided in previous accounting pronouncements.

SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. Earlier application is encouraged, provided that the reporting entity has not yet issued financial statements for that fiscal year, including financial statements for an interim period within that fiscal year. All valuation adjustments will be recognized as cumulative-effect adjustments to the opening balance of retained earnings for the fiscal year in which SFAS 157 is initially applied. In December 2007, the FASB provided a one year deferral of SFAS 157 for nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value on a recurring basis, at least annually. We will adopt SFAS 157 on January 1, 2008, for our financial assets and liabilities, which primarily consists of derivatives we record in accordance with SFAS 133, and on January 1, 2009, for our non-financial assets and liabilities. For our financial assets and liabilities, we expect that our adoption of SFAS 157 will primarily impact our disclosures and not have a material impact on our consolidated results of operations, cash flows or financial position. We are currently evaluating the impact with respect to our non-financial assets and liabilities.

SFAS 159 In February 2007, the FASB issued SFAS 159 which is effective for fiscal years beginning after November 15, 2007, but is not required to be adopted. SFAS 159 establishes a framework for measuring fair value for eligible financial assets and liabilities with the intention of reducing earnings volatility. We currently have no financial assets or liabilities eligible for this treatment and have no plans to adopt SFAS 159.

SFAS 160 In December 2007, the FASB issued SFAS 160, which is effective for fiscal years beginning after December 15, 2008. Early adoption is prohibited. SFAS 160 will require us to present our minority interest, to be referred to as a noncontrolling interest, separately within the capitalization section of our consolidated balance sheet. We will adopt SFAS 160 as of January 1, 2009.

FIN 39 was issued in March 1992 and provides guidance related to offsetting payable and receivable amounts related to certain contracts, including derivative contracts. It was effective for financial statements issued for periods beginning after December 15, 1993.

FSP FIN 39-1 was issued in April 2007 and is effective for us on January 1, 2008. FIN 39-1 amends FIN 39 and allows a company to elect to report certain derivative assets and liabilities subject to master netting agreements on either a gross basis or net basis on the balance sheet. The guidance also addresses reporting of collateral amounts relating to the netting agreements. We enter into derivative contracts, but FSP FIN 39-1 will not have a material effect on our consolidated financial condition.

ITEM 7A. 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 natural gas. 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 establishing the overall risk management policies and monitoring compliance with, and adherence to, the terms within these policies, including approval and authorization levels and delegation of these levels. Our RMC consists of members of senior management who monitor open commodity price risk positions and other types of risk, corporate exposures, credit exposures and overall results of our risk management activities. It 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 2, Financial Instruments and Risk Management.

Commodity Price Risk

Retail Energy Operations SouthStar's use of derivatives is governed by a risk management policy, approved and monitored by its Risk and Asset Management Committee, which prohibits the use of derivatives for speculative purposes.

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

We have designated a portion of SouthStar's derivative transactions as cash flow hedges in accordance with SFAS 133. We record derivative gains or losses arising from cash flow hedges in OCI and reclassify them into earnings in the same period as the underlying hedged item occurs and is recorded in earnings. We record any hedge ineffectiveness, defined as when the gains or losses on the hedging instrument do not offset and are greater than the losses or gains on the hedged item, in cost of gas in our consolidated statement of income in the period in which the ineffectiveness occurs. SouthStar currently has minimal hedge ineffectiveness. We have not designated the remainder of SouthStar's derivative instruments as hedges under SFAS 133 and, accordingly, we record changes in their fair value in earnings in the period of change.

SouthStar recorded a net unrealized loss related to changes in the fair value of derivative instruments utilized in its energy marketing and risk management activities of $7 million during 2007, $14 million of unrealized gains during 2006 and unrealized losses of $4 million during 2005. The following tables illustrate the change in the net fair value of the derivative instruments and energy-trading contracts during 2007, 2006 and 2005 and provide details of the net fair value of contracts outstanding as of December 31, 2007, 2006 and 2005.

In millions	**2007**	**2006**	**2005**
Net fair value of contracts outstanding at beginning of period	$17	$3	$7
Contracts realized or otherwise settled during period	(16)	(3)	(7)
Change in net fair value of contracts	9	17	3
Net fair value of contracts outstanding at end of period	$10	$17	$3

The sources of SouthStar's net fair value at December 31, 2007, are as follows.

In millions	**Prices actively quoted** (1)	**Prices provided by other external sources** (2)
Mature through 2008	$5	$5
Matures after 2008	-	-
Total net fair value	$5	$5

(1) Valued using NYMEX futures prices.
(2) Values primarily related to weather derivative transactions that are valued on an intrinsic basis in accordance with EITF 99-02 as based on heating degree days.

SouthStar routinely utilizes various types of financial and other instruments to mitigate certain commodity price and weather risks inherent in the natural gas industry. These instruments include a variety of exchange-traded and over-the-counter energy contracts, such as forward contracts, futures contracts, options contracts and swap agreements. The following table includes the fair values and average values of SouthStar's energy marketing and risk management assets and liabilities as of December 31, 2007 and 2006. SouthStar bases the average values on monthly averages for the 12 months ended December 31, 2007 and 2006.

	Average values at December 31,	
In millions	**2007**	**2006**
Asset	$11	$11
Liability	4	6

	Fair value at December 31,	
In millions	**2007**	**2006**
Asset	$12	$30
Liability	2	13

Value-at-risk A 95% confidence interval is used to evaluate VaR exposure. A 95% confidence interval means there is a 5% confidence that the actual loss 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 distribution, 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. SouthStar's portfolio of positions for 2007 and 2006, had annual average 1-day holding period VaRs of less than $100,000, and its high, low and period end 1-day holding period VaR were immaterial.

Wholesale Services Sequent routinely uses various types of financial and other instruments to mitigate certain commodity price risks inherent in the natural gas industry. These instruments include a variety of exchange-traded and over-the-counter energy contracts, such as forward contracts, futures contracts, options contracts and financial swap agreements.

Energy Marketing and Risk Management Activities We account for derivative transactions in connection with Sequent's energy marketing activities on a fair value basis in accordance with SFAS 133. We record 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.

Sequent's energy-trading contracts are recorded on an accrual basis as required under the EITF 02-03 rescission of EITF 98-10, unless they are derivatives that must be recorded at fair value under SFAS 133.

Sequent recorded a net unrealized loss related to changes in the fair value of derivative instruments utilized in its energy marketing and risk management activities and contract settlement of $62 million during 2007, $132 million of unrealized gains during 2006 and unrealized losses of $30 million during 2005. The following tables illustrate the change in the net fair value of Sequent's derivative instruments and energy-trading contracts during 2007, 2006 and 2005 and provide details of the net fair value of contracts outstanding as of December 31, 2007, 2006 and 2005.

In millions	**2007**	**2006**	**2005**
Net fair value of contracts outstanding at beginning of period	$119	$(13)	$17
Contracts realized or otherwise settled during period	(102)	17	(47)
Change in net fair value of contracts	40	115	17
Net fair value of contracts outstanding at end of period	$57	$119	$(13)

The sources of Sequent's net fair value at December 31, 2007, are as follows.

In millions	**Prices actively quoted** (1)	**Prices provided by other external sources** (2)
Mature through 2008	$19	$31
Mature 2009 – 2010	1	2
Mature 2011 – 2013	-	3
Mature after 2013	-	1
Total net fair value	$20	$37

(1) Valued using NYMEX futures prices.
(2) Valued using basis transactions that represent the cost to transport the commodity from a NYMEX delivery point to the contract delivery point. These transactions are based on quotes obtained either through electronic trading platforms or directly from brokers.

The following table includes the fair values and average values of Sequent's energy marketing and risk management assets and liabilities as of December 31, 2007 and 2006. Sequent bases the average values on monthly averages for the 12 months ended December 31, 2007 and 2006.

	Average values at December 31,	
In millions	**2007**	**2006**
Asset	$63	$95
Liability	16	43

	Fair value at December 31,	
In millions	**2007**	**2006**
Asset	$70	$133
Liability	13	14

Value-at-risk Sequent employs a systematic approach to evaluating and managing the risks associated with contracts related to wholesale marketing and risk management, including VaR. Similar to SouthStar, Sequent uses a 1-day holding period and a 95% confidence interval to evaluate its VaR exposure.

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

Sequent's management actively monitors open commodity positions and the resulting VaR. Sequent continues to maintain a relatively matched book, where its total buy volume is close to its sell volume, with minimal open commodity risk. Based on a 95% confidence interval and employing a 1-day holding period for all positions, Sequent's portfolio of positions for the 12 months ended December 31, 2007, 2006 and 2005 had the following 1-day holding period VaRs.

In millions	**2007**	**2006**	**2005**
Period end	$1.2	$1.3	$0.6
12-month average	1.3	1.2	0.4
High	2.3	2.5	1.1
Low (1)	0.7	0.7	0.0

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

Interest Rate Risk

Interest rate fluctuations expose our variable-rate debt to changes in interest expense and cash flows. We manage interest expense using a combination of fixed-rate and variable-rate debt. Based on $840 million of variable-rate debt, which includes $579 million of our variable-rate short-term debt, $100 million of variable-rate senior notes and $161 million of variable-rate gas facility revenue bonds outstanding at December 31, 2007, a 100 basis point change in market interest rates from 5.56% to 6.56% would have resulted in an increase in pretax interest expense of $8 million on an annualized basis.

To facilitate the achievement of desired fixed-rate to variable-rate debt ratios, AGL Capital entered into interest rate swaps whereby it agreed to exchange, fixed rate debt for floating-rate debt. The swaps exchange at specified intervals, the difference between fixed and variable amounts calculated by reference to agreed-on notional principal amounts. These swaps are designated to hedge the fair values of $100 million of the $300 million senior notes due in 2011.

In August 2007, we executed a treasury-lock agreement covering a notional amount totaling $125 million to hedge the interest rate risk associated with our $125 million senior notes offering in December 2007. The 10-year treasury interest rate was locked in at a weighted average rate of 4.5%. The treasury-lock agreements settled and we paid $5 million in December 2007 in connection with our issuance of $125 million in senior notes. The $5 million is included within OCI (net of $2 million in income taxes) and will be amortized over the remaining life of the senior notes (through July 2016) as interest expense.

Credit Risk

Distribution Operations Atlanta Gas Light has a concentration of credit risk as it bills only 12 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. 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 2007, the four largest Marketers based on customer count, one of which was SouthStar, accounted for approximately 38% of our consolidated operating margin and 52% 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 on a monthly basis the adequacy of credit support coverage, credit rating profiles of credit support providers and payment status of each Marketer. 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 of interstate pipeline transportation and storage capacity to Marketers. 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.

Retail Energy Operations SouthStar obtains credit scores for its firm residential and small commercial customers using a national credit reporting agency, enrolling only those customers that meet or exceed SouthStar's credit threshold.

SouthStar considers potential interruptible and large commercial customers based on a review of publicly available financial statements and review of commercially available credit reports. Prior to entering into a physical transaction, SouthStar also assigns physical wholesale counterparties an internal credit rating and credit limit based on the counterparties' Moody's, S&P and Fitch ratings, commercially available credit reports and audited financial statements.

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

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

Sequent, which provides services to retail 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, 2007, Sequent's top 20 counterparties represented approximately 53% of the total counterparty exposure of $366 million, derived by adding together the top 20 counterparties' exposures and dividing by the total of Sequent's counterparties' exposures.

As of December 31, 2007, Sequent's counterparties, or the counterparties' guarantors, had a weighted average S&P equivalent credit rating of A-, which is consistent with the prior year. The S&P equivalent credit rating is determined by a process of converting the lower of the S&P or Moody's ratings to an internal rating ranging from 9 to 1, with 9 being equivalent to AAA/Aaa by S&P and Moody's and 1 being D or Default by S&P and Moody's. A counterparty that does not have an external rating is assigned an internal rating based on the strength of the financial ratios of that counterparty. To arrive at the weighted average credit rating, each counterparty's assigned internal rating is multiplied by the counterparty's credit exposure and summed for all counterparties. That sum is divided by the aggregate total counterparties' exposures, and this numeric value is then converted to an S&P equivalent.

The following table shows Sequent's commodity receivable and payable positions as of December 31, 2007 and 2006.

	As of December 31,			
	Gross receivables		**Gross payables**	
In millions	**2007**	**2006**	**2007**	**2006**
Netting agreements in place:				
Counterparty is investment grade	$437	$359	$356	$297
Counterparty is non-investment grade	24	62	18	52
Counterparty has no external rating	135	75	204	156
No netting agreements in place:				
Counterparty is investment grade	3	9	-	5
Amount recorded on balance sheet	$599	$505	$578	$510

Sequent has certain trade and credit contracts that have explicit minimum credit rating requirements. These credit rating requirements typically give counterparties the right to suspend or terminate credit if our credit ratings are downgraded to non-investment grade status. Under such circumstances, Sequent would need to post collateral to continue transacting business with some of its counterparties. Posting collateral would have a negative effect on our liquidity. If such collateral were not posted, Sequent's ability to continue transacting business with these counterparties would be impaired. If at December 31, 2007, Sequent's credit ratings had been downgraded to non-investment grade status, the required amounts to satisfy potential collateral demands under such agreements between Sequent and its counterparties would have totaled $26 million.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

AGL Resources Inc.
Consolidated Balance Sheets - Assets

In millions	As of December 31, 2007	As of December 31, 2006
Current assets		
Cash and cash equivalents	$21	$20
Receivables		
Energy marketing	599	505
Gas	212	197
Unbilled revenues	179	172
Other	13	21
Less allowance for uncollectible accounts	(14)	(15)
Total receivables	989	880
Inventories		
Natural gas stored underground	521	568
Other	30	29
Total inventories	551	597
Energy marketing and risk management assets	78	159
Unrecovered PRP costs – current portion	31	27
Unrecovered environmental remediation costs – current portion	23	27
Other current assets	118	112
Total current assets	1,811	1,822
Property, plant and equipment		
Property, plant and equipment	5,177	4,976
Less accumulated depreciation	1,611	1,540
Property, plant and equipment – net	3,566	3,436
Deferred debits and other assets		
Goodwill	420	420
Unrecovered PRP costs	254	247
Unrecovered environmental remediation costs	135	143
Other	82	79
Total deferred debits and other assets	891	889
Total assets	$6,268	$6,147

See Notes to Consolidated Financial Statements.

AGL Resources Inc.
Consolidated Balance Sheets - Liabilities and Capitalization

In millions, except share amounts	As of December 31, 2007	December 31, 2006
Current liabilities		
Short-term debt	$580	$539
Energy marketing trade payable	578	510
Accounts payable – trade	172	213
Accrued PRP costs – current portion	55	35
Accrued interest	39	37
Customer deposits	35	42
Deferred purchased gas adjustment	28	24
Accrued wages and salaries	24	50
Energy marketing and risk management liabilities – current portion	18	41
Accrued environmental remediation costs – current portion	10	13
Other current liabilities	106	162
Total current liabilities	1,645	1,666
Accumulated deferred income taxes	566	505
Long-term liabilities (excluding long-term debt)		
Accrued PRP costs	190	202
Accumulated removal costs	169	162
Accrued environmental remediation costs	97	83
Accrued pension obligations	43	78
Accrued postretirement benefit costs	24	32
Other long-term liabilities	152	146
Total long-term liabilities (excluding long-term debt)	675	703
Commitments and contingencies (see Note 7)		
Minority interest	47	42
Capitalization		
Long-term debt	1,674	1,622
Common shareholders' equity, $5 par value; 750 million shares authorized; 76.4 million and 77.7 million shares outstanding at December 31, 2007 and 2006	1,661	1,609
Total capitalization	3,335	3,231
Total liabilities and capitalization	$6,268	$6,147

See Notes to Consolidated Financial Statements.

AGL Resources Inc.
Statements of Consolidated Income

In millions, except per share amounts	Years ended December 31, 2007	2006	2005
Operating revenues	$2,494	$2,621	$2,718
Operating expenses			
Cost of gas	1,369	1,482	1,626
Operation and maintenance	451	473	477
Depreciation and amortization	144	138	133
Taxes other than income taxes	41	40	40
Total operating expenses	2,005	2,133	2,276
Operating income	489	488	442
Other income (expenses)	4	(1)	(1)
Minority interest	(30)	(23)	(22)
Interest expense	(125)	(123)	(109)
Earnings before income taxes	338	341	310
Income taxes	127	129	117
Net income	$211	$212	$193
Per common share data			
Basic earnings per common share	$2.74	$2.73	$2.50
Diluted earnings per common share	$2.72	$2.72	$2.48
Cash dividends declared per common share	$1.64	$1.48	$1.30
Weighted average number of common shares outstanding			
Basic	77.1	77.6	77.3
Diluted	77.4	78.0	77.8

See Notes to Consolidated Financial Statements.

AGL Resources Inc.
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 loss	Shares held in treasury and trust	Total
Balance as of December 31, 2004	76.7	384	632	415	(46)	-	1,385
Comprehensive income:							
Net income	-	-	-	193	-	-	193
OCI - loss resulting from unfunded pension and postretirement obligation (net of tax of $3)	-	-	-	-	(5)	-	(5)
Unrealized loss from hedging activities (net of tax of $1)	-	-	-	-	(2)	-	(2)
Total comprehensive income							186
Dividends on common stock ($1.30 per share)	-	-	-	(100)	-	-	(100)
Issuance of common shares:							
Benefit, stock compensation, dividend reinvestment and stock purchase plans (net of tax of $9)	1.1	5	23	-	-	-	28
Balance as of December 31, 2005	77.8	389	655	508	(53)	-	1,499
Comprehensive income:							
Net income	-	-	-	212	-	-	212
OCI - gain resulting from unfunded pension and postretirement obligation (net of tax of $7)	-	-	-	-	11	-	11
Unrealized gain from hedging activities (net of tax of $7)	-	-	-	-	10	-	10
Total comprehensive income							233
Dividends on common stock ($1.48 per share)	-	-	1	(115)	-	3	(111)
Benefit, stock compensation, dividend reinvestment and stock purchase plans	0.3	1	2	-	-	-	3
Issuance of treasury shares	0.6	-	(3)	(4)	-	21	14
Purchase of treasury shares	(1.0)	-	-	-	-	(38)	(38)
Stock-based compensation expense (net of tax of $5)	-	-	9	-	-	-	9
Balance as of December 31, 2006	77.7	390	664	601	(32)	(14)	1,609
Comprehensive income:							
Net income	-	-	-	211	-	-	211
OCI - gain resulting from unfunded pension and postretirement obligation (net of tax of $16)	-	-	-	-	24	-	24
Unrealized gain from hedging activities (net of tax of $3)	-	-	-	-	(5)	-	(5)
Total comprehensive income							230
Dividends on common stock ($1.64 per share)	-	-	-	(127)	-	4	(123)
Issuance of treasury shares	0.7	-	(6)	(5)	-	27	16
Purchase of treasury shares	(2.0)	-	-	-	-	(80)	(80)
Stock-based compensation expense (net of tax of $3)	-	-	9	-	-	-	9
Balance as of December 31, 2007	76.4	$390	$667	$680	$(13)	$(63)	$1,661

See Notes to Consolidated Financial Statements.

AGL Resources Inc.
Statements of Consolidated Cash Flows

In millions	Years ended December 31, 2007	2006	2005
Cash flows from operating activities			
Net income	$211	$212	$193
Adjustments to reconcile net income to net cash flow provided by operating activities			
Depreciation and amortization	144	138	133
Change in energy marketing and risk management assets and liabilities	69	(130)	27
Minority interest	30	23	22
Deferred income taxes	30	133	17
Changes in certain assets and liabilities			
Inventories	46	(54)	(211)
Gas, unbilled and other receivables	(15)	170	(170)
Energy marketing receivables and energy marketing trade payables, net	(26)	(95)	93
Accrued expenses	(34)	15	12
Trade payables	(41)	(53)	57
Other – net	(38)	(5)	(93)
Net cash flow provided by operating activities	376	354	80
Cash flows from investing activities			
Expenditures for property, plant and equipment	(259)	(253)	(267)
Sale of Saltville	-	-	66
Other	6	5	7
Net cash flow used in investing activities	(253)	(248)	(194)
Cash flows from financing activities			
Dividends paid on common shares	(123)	(111)	(100)
Purchase of treasury shares	(80)	(38)	-
Payments of trust preferred securities	(75)	(150)	-
Distribution to minority interest	(23)	(22)	(19)
Payments of medium-term notes	(11)	-	-
Issuances of senior notes	125	175	-
Net payments and borrowings of short-term debt	52	6	188
Issuance of treasury shares	16	14	-
Sale of common stock	-	3	28
Other	(3)	5	-
Net cash flow (used in) provided by financing activities	(122)	(118)	97
Net increase (decrease) in cash and cash equivalents	1	(12)	(17)
Cash and cash equivalents at beginning of period	20	32	49
Cash and cash equivalents at end of period	$21	$20	$32
Cash paid during the period for			
Interest	$127	$109	$115
Income taxes	118	37	89

See Notes to Consolidated Financial Statements.

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,” the “company”, or “AGL Resources” mean consolidated AGL Resources Inc. and its subsidiaries. We have prepared the accompanying consolidated financial statements under the rules of the SEC. For a glossary of key terms and referenced accounting standards, see page 4.

Basis of Presentation

Our consolidated financial statements as of and for the period ended December 31, 2007, 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. We have eliminated any intercompany profits and transactions in consolidation; however, we have not eliminated intercompany profits when such amounts are probable of recovery under the affiliates’ rate regulation process. Certain amounts from prior periods have been reclassified and revised to conform to the current period presentation.

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. We record the earnings allocated to Piedmont as a minority interest in our consolidated statements of income and we record Piedmont’s portion of SouthStar’s capital as a minority interest in our consolidated balance sheets.

We are the primary beneficiary of SouthStar’s activities and have determined that SouthStar is a variable interest entity as defined by FIN 46 revised in December 2003, FIN 46R. We determined that SouthStar was a variable interest entity because our equal voting rights with Piedmont are not proportional to our economic obligation to absorb 75% of any losses or residual returns from SouthStar, except those losses and returns related to customers in Ohio and Florida. Earnings related to SouthStar’s customers in Ohio and Florida are allocated 70% to us and 30% to Piedmont. In addition, SouthStar obtains substantially all its transportation capacity for delivery of natural gas through our wholly owned subsidiary, Atlanta Gas Light.

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

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. We bill customers 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. We write off accounts once we deem them to be uncollectible.

Inventories

For our distribution operations subsidiaries, we record natural gas stored underground at weighted average costs. For Sequent and SouthStar, we account for natural gas inventory at the lower of weighted average cost or market.

Sequent and SouthStar evaluate the average cost of their natural gas inventories against market prices to determine whether any declines in market prices below the average cost are other than temporary. For any declines considered to be other than temporary, adjustments are recorded to reduce the weighted average cost of the natural gas inventory to market. Consequently, as a result of declining natural gas prices, Sequent recorded an adjustment against cost of gas to reduce the value of its inventories to market value of $4 million in 2007, $43 million in 2006 and $3 million in 2005. SouthStar recorded a $6 million adjustment in 2006, but was not required to make a similar adjustment in 2007 or 2005.

For volumes of gas stored under park and loan arrangements that are payable or to be repaid at predetermined dates to third parties, we record the inventory at fair value. Materials and supplies inventories are stated at the lower of average cost or market.

In Georgia's competitive environment, Marketers including SouthStar, our marketing subsidiary, 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

A summary of our PP&E by classification as of December 31, 2007 and 2006 is provided in the following table.

In millions	2007	2006
Transmission and distribution	$4,193	$4,047
Storage	285	267
Other	509	454
Construction work in progress	190	208
Total gross PP&E	5,177	4,976
Accumulated depreciation	(1,611)	(1,540)
Total net PP&E	$3,566	$3,436

Distribution Operations PP&E expenditures consist of property and equipment that is in use, being held for future use and under construction. We report PP&E at its original cost, which includes:

- material and labor
- contractor costs
- construction overhead costs
- an allowance for funds used during construction (AFUDC) which represents the estimated cost of funds used to finance the construction of major projects and is capitalized in rate base for ratemaking purposes when the completed projects are placed in service

We charge property retired or otherwise disposed of to accumulated depreciation since such costs are recovered in rates.

Retail Energy Operations, Wholesale Services, Energy Investments and Corporate PP&E expenditures include property that is in use and under construction, and we report it at cost. We record a gain or loss for retired or otherwise disposed-of property. Natural gas in storage at Jefferson Island that is retained as pad gas (volumes of non-working natural gas used to maintain the operational integrity of the cavern facility) is classified as non-depreciable property, plant and equipment and is valued at cost.

Depreciation Expense

We compute depreciation expense for distribution operations by applying composite, straight-line rates (approved by the state regulatory agencies) to the investment in depreciable property. The composite straight-line depreciation rate for depreciable property -- excluding transportation equipment for Atlanta Gas Light, Virginia Natural Gas and Chattanooga Gas -- was approximately 2.5% during 2007, 2.5% during 2006 and 2.6% during 2005. The composite, straight-line rate for Elizabethtown Gas, Florida City Gas and Elkton Gas was approximately 3.2 % for 2007, 3.0% during 2006 and 3.1% in 2005. 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 up to 35 years based on the useful life of the asset.

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 8.53%, and the Tennessee Commission has authorized a rate of 7.89%.Prior to January 1, 2007, the Tennessee Commission had authorized a rate of 7.43%. The New Jersey Commission has authorized a variable rate based on the FERC method of accounting for AFUDC. At December 31, 2007 the rate was 5.2%. The total AFUDC for 2007 was $4 million, 2006 was $5 million and 2005 was $4 million. The capital expenditures of our other regulated utilities do not qualify for AFUDC treatment.

Goodwill

We have included $420 million of goodwill in our consolidated balance sheets as of December 31, 2007, of which $229 million is related to our acquisition of NUI in November 2004; $170 million is related to our acquisition of Virginia Natural Gas in 2000; $14 million is related to our acquisition of Jefferson Island in October 2004 and $7 million is related to our acquisition of Chattanooga Gas in 1988.

SFAS 142 requires us to perform an annual goodwill impairment test at a reporting unit level which generally equates to our operating segments as discussed in Note 9 "Segment Information." We have not recognized any impairment charges in 2007, 2006 or 2005. We also assess goodwill for impairment if events or changes in circumstances may indicate an impairment of goodwill exists. When such events or circumstances are present, we assess the recoverability of long-lived assets by determining whether the carrying value will be recovered through the expected future cash flows. In the event the sum of the expected future cash flows resulting from the use of the asset is less than the carrying value of the asset, we record an impairment loss equal to the excess of the asset's carrying value over its fair value. We conduct this assessment principally through a review of financial results, changes in state and federal legislation and regulation, regulatory and legal proceedings and the periodic regulatory filings for our regulated utilities.

Taxes

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 we generally depreciate assets for tax purposes over a shorter period of time than for book purposes. The determination of our provision for income taxes requires significant judgment, the use of estimates, and the interpretation and application of complex tax laws. Significant judgment is required in assessing the timing and amounts of deductible and taxable items. We report the tax effects of depreciation and other differences in those items as deferred income tax assets or liabilities in our consolidated balance sheets in accordance with SFAS 109 and FIN 48. Investment tax credits of approximately $16 million previously deducted for income tax purposes for Atlanta Gas Light, Elizabethtown Gas, Florida City Gas and Elkton Gas 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.

State and local taxes We collect and remit various taxes on behalf of various governmental authorities. We record these amounts in our consolidated balance sheets except taxes in the state of Florida which we are required to include in revenues and operating expenses. These Florida related taxes are not material for any periods presented.

Revenues

Distribution operations We record revenues when services are provided to customers. Those revenues are based on rates approved by the state regulatory commissions of our utilities.

As required by the Georgia Commission, in July 1998, Atlanta Gas Light began billing Marketers in equal monthly installments for each residential, commercial and industrial customer's distribution costs. 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, 2007 and 2006 (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 Elizabethtown Gas, Virginia Natural Gas, Florida City Gas, Chattanooga Gas and Elkton 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. Revenues from residential and certain commercial and industrial customers are recognized 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 last 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 on actual deliveries to the end of the period.

The tariffs for Elizabethtown Gas, Virginia Natural Gas and Chattanooga Gas contain WNA's that partially 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.

Retail energy operations We record retail energy operations' revenues when services are provided to customers. Revenues from sales and transportation services are recognized in the same period in which the related volumes are delivered to customers. Sales revenues from residential and certain commercial and industrial customers are recognized 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 most recent 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 on actual deliveries to the end of the period.

Wholesale services We record wholesale services' revenues when services are provided to customers. 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 133 are recorded at fair value with changes in fair value recognized in earnings in the period of change and characterized as unrealized gains or losses.

Energy investments We record operating revenues at Jefferson Island in the period in which actual volumes are transported and storage services are provided. The majority of our storage services are covered under medium to long-term contracts at a fixed market rate.

We record operating revenues at AGL Networks from leases of dark fiber pursuant to indefeasible rights-of-use (IRU) agreements as services are provided. Dark fiber IRU agreements generally require the customer to make a down payment upon execution of the agreement; however in some cases AGL Networks receives up to the entire lease payment at the inception of the lease and recognizes ratably over the lease term. AGL Networks had deferred revenue in our consolidated balance sheet of $38 million at December 31, 2007 and $37 million at December 31, 2006. In addition, AGL Networks recognizes sales revenues upon the execution of certain sales-type agreements for dark fiber when the agreements provide for the transfer of legal title to the dark fiber to the customer at the end of the agreement's term. This sales-type accounting treatment is in accordance with EITF 00-11 and SFAS 66, which provides that such transactions meet the criteria for sales-type lease accounting if the agreement obligates the lessor to convey ownership of the underlying asset to the lessee by the end of the lease term.

Cost of gas

Excluding Atlanta Gas Light, we charge our utility customers for natural gas consumed using 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 or billed to customers in a given period. The deferred amount is either billed or refunded to our customers prospectively through adjustments to the commodity rate.

Our retail energy operations customers are charged for natural gas consumed. We also include within our cost of gas amounts for fuel and lost and unaccounted for gas, adjustments to reduce the value of our inventories to market value and for gains and losses associated with derivatives.

Comprehensive Income

Our comprehensive income includes net income plus OCI, which includes other gains and losses affecting shareholders' equity that GAAP excludes from net income. Such items consist primarily of unrealized gains and losses on certain derivatives designated as cash flow hedges and overfunded or unfunded pension obligation adjustments. The following table illustrates our OCI activity during 2007, 2006 and 2005.

In millions	2007	2006	2005
Cash flow hedges:			
Net derivative unrealized gains arising during the period (net of $7 and $3 in taxes)	$-	$11	$5
Less reclassification of realized gains included in income (net of $3, $1 and $4 in taxes)	(5)	(1)	(7)
Over funded (unfunded) pension obligation (net of $16, $7 and $3 in taxes)	24	11	(5)
Total	$19	$21	$(7)

Earnings Per Common Share

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

We derive our potentially dilutive common shares by calculating the number of shares issuable under restricted stock, restricted stock units and stock options. The future issuance of shares underlying the restricted stock and restricted stock 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. There were no material antidilutive options in 2007, 2006 or 2005. The following table shows the calculation of our diluted earnings per share for the periods presented if performance units currently earned under the plan ultimately vest and if stock options currently exercisable at prices below the average market prices are exercised.

In millions	2007	2006	2005
Denominator for basic earnings per share (1)	77.1	77.6	77.3
Assumed exercise of potential common shares	0.3	0.4	0.5
Denominator for diluted earnings per share	77.4	78.0	77.8

(1) Daily weighted average shares outstanding.

Regulatory Assets and Liabilities

We have recorded regulatory assets and liabilities in our consolidated balance sheets in accordance with SFAS 71. Our regulatory assets and liabilities, and associated liabilities for our unrecovered PRP costs, unrecovered ERC and the associated assets and liabilities for our Elizabethtown Gas hedging program, are summarized in the following table.

	December 31,	
In millions	2007	2006
Regulatory assets		
Unrecovered PRP costs	$285	$274
Unrecovered ERC (1)	158	170
Elizabethtown Gas hedging program	-	16
Unrecovered postretirement benefit costs	12	13
Unrecovered seasonal rates	11	11
Unrecovered PGA	23	14
Other	23	20
Total regulatory assets	512	518
Associated assets		
Elizabethtown Gas hedging program	4	-
Total regulatory and associated assets	$516	$518
Regulatory liabilities		
Accumulated removal costs	$169	$162
Elizabethtown Gas hedging program	4	-
Unamortized investment tax credit	16	18
Deferred PGA	28	24
Regulatory tax liability	20	22
Other	19	18
Total regulatory liabilities	256	244
Associated liabilities		
PRP costs	245	237
ERC (1)	96	87
Elizabethtown Gas hedging program	-	16
Total associated liabilities	341	340
Total regulatory and associated liabilities	$597	$584

(1) For a discussion of ERC, see Note 7.

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, and be classified as an extraordinary item. Although the natural 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 preceding table are included in base rates except for the unrecovered PRP costs, unrecovered ERC and the deferred PGA, which are recovered through specific rate riders on a dollar for dollar basis. 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 ERC. The ERC 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. ERC 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. Elizabethtown Gas' hedging program asset and liability reflect unrealized losses or gains that will be recovered from or passed to rate payers through the PGA on a dollar for dollar basis, once the losses or gains are realized. Unrecovered postretirement benefit costs are recoverable through base rates over the next 6 to 25 years based on the remaining recovery period as designated by the applicable state regulatory commissions. Unrecovered seasonal rates reflect the difference between the recognition of a portion of Atlanta Gas Light's residential base rates revenues on a straight-line basis as compared to the collection of the revenues over a seasonal pattern. The unrecovered amounts are fully recoverable through base rates within one year.

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

Atlanta Gas Light The PRP, ordered by the Georgia Commission to be administered by Atlanta Gas Light, requires, among other things, that Atlanta Gas Light 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 320 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.

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 straight fixed variable 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

On June 10, 2005, Atlanta Gas Light and the Georgia Commission entered into a Settlement Agreement that, among other things, extends Atlanta Gas Light's PRP by five years to require that all replacements be completed by December 2013. The timing of replacements was subsequently specified in an amendment to the PRP stipulation. This amendment, which was approved by the Georgia Commission on December 20, 2005, requires Atlanta Gas Light to replace all cast iron pipe and 70% of all bare steel pipe by December 2010. The remaining 30% of bare steel pipe is required to be replaced by December 2013.

Under the Settlement Agreement, base rates charged to customers will remain unchanged through April 30, 2010, but Atlanta Gas Light will recognize reduced base rate revenues of $5 million on an annual basis through April 30, 2010. The five-year total reduction in recognized base rate revenues of $25 million will be applied to the allowed amount of costs incurred to replace pipe, which will reduce the amounts recovered from customers under the PRP rider. The Settlement Agreement also set the per customer fixed PRP rate that Atlanta Gas Light will charge at $1.29 per customer per month from May 2005 through September 2008 and at $1.95 from October 2008 through December 2013 and includes a provision that allows for a true-up of any over- or under-recovery of PRP revenues that may result from a difference between PRP charges collected through fixed rates and actual PRP revenues recognized through the remainder of the program.

The Settlement Agreement also allows Atlanta Gas Light to recover through the PRP $4 million of the $32 million capital costs associated with its March 2005 purchase of 250 miles of pipeline in central Georgia from Southern Natural Gas Company, a subsidiary of El Paso Corporation. The remaining capital costs are included in Atlanta Gas Light's rate base and collected through base rates.

Atlanta Gas Light has recorded a long-term regulatory asset of $254 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 $31 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:

- $27 million in 2007
- $27 million in 2006
- $26 million in 2005

As of December 31, 2007, Atlanta Gas Light had recorded a current liability of $55 million, representing expected program expenditures for the next 12 months and a long-term liability of $190 million, representing expected program expenditures starting in 2009 through the end of the program in 2013.

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.

Elizabethtown Gas In August 2006, the New Jersey Commission issued an order adopting a pipeline replacement cost recovery rider program for the replacement of certain 8" cast iron main pipes and any unanticipated 10"-12" cast iron main pipes integral to the replacement of the 8" main pipes. The order allows Elizabethtown Gas to recognize revenues under a deferred recovery mechanism for costs to replace the pipe that exceeds a baseline amount of $3 million. Elizabethtown Gas' recognition of these revenues could be disallowed by the New Jersey Commission if its return on equity exceeds the authorized rate of 10%. The term of the stipulation is from the date of the order through December 31, 2008. Total replacement costs through December 31, 2008 are expected to be $17 million, of which $14 million will be eligible for the deferred recovery mechanism. Revenues recognized and deferred for recovery under the stipulation are estimated to be approximately $1 million. All costs incurred under the program will be included in Elizabethtown Gas' next rate case to be filed in 2009.

Use of Accounting Estimates

The preparation of our financial statements in conformity with GAAP 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, and we evaluate our estimates on an ongoing basis. Each of our estimates involve complex situations requiring a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our financial statements. The most significant estimates include our PRP accruals, environmental liability accruals, uncollectible accounts and other allowance for contingencies, pension and postretirement obligations, derivative and hedging activities and provision for income taxes. Our actual results could differ from our estimates.

Accounting Developments

SFAS 157 In September 2006, the FASB issued SFAS 157, which establishes a framework for measuring fair value and requires expanded disclosures regarding fair value measurements. SFAS 157 does not require any new fair value measurements. However, it eliminates inconsistencies in the guidance provided in previous accounting pronouncements.

SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. Earlier application is encouraged, provided that the reporting entity has not yet issued financial statements for that fiscal year, including financial statements for an interim period within that fiscal year. All valuation adjustments will be recognized as cumulative-effect adjustments to the opening balance of retained earnings for the fiscal year in which SFAS 157 is initially applied. In December 2007, the FASB provided a one year deferral of SFAS 157 for nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value on a recurring basis, at least annually. We will adopt SFAS 157 on January 1, 2008, for our financial assets and liabilities, which primarily consists of derivatives we record in accordance with SFAS 133, and on January 1, 2009, for our non-financial assets and liabilities. For our financial assets and liabilities, we expect that our adoption of SFAS 157 will primarily impact our disclosures and not have a material impact on our consolidated results of operations, cash flows and financial position. We are currently evaluating the impact with respect to our non-financial assets and liabilities.

SFAS 159 In February 2007, the FASB issued SFAS 159 which is effective for fiscal years beginning after November 15, 2007 but is not required to be adopted. SFAS 159 establishes a framework for measuring fair value for eligible financial assets and liabilities with the intention of reducing earnings volatility. We currently have no financial assets or liabilities eligible for this treatment and have no plans to adopt SFAS 159.

SFAS 160 In December 2007, the FASB issued SFAS 160, which is effective for fiscal years beginning after December 15, 2008. Early adoption is prohibited. SFAS 160 will require us to present our minority interest, now to be referred to as a noncontrolling interest, separately within the capitalization section of our consolidated balance sheet. We will adopt SFAS 160 as of January 1, 2009.

FIN 39 was issued in March 1992 and provides guidance related to offsetting payable and receivable amounts related to certain contracts, including derivative contracts. It was effective for financial statements issued for periods beginning after December 15, 1993.

FSP FIN 39-1 was issued in April 2007 and is effective for us on January 1, 2008. FIN 39-1 amends FIN 39 and allows a company to elect to report certain derivative assets and liabilities subject to master netting agreements on either a gross basis or net basis on the balance sheet. The guidance also addresses reporting of collateral amounts relating to the netting agreements. We enter into derivative contracts, but FSP FIN 39-1 will not have a material effect on our consolidated financial condition.

Note 2 – Financial Instruments and Risk Management

Financial Instruments

The carrying value of cash and cash equivalents, receivables, accounts payable, other current liabilities, derivative assets, derivative liabilities and accrued interest approximate fair value. The following table shows the carrying amounts and fair values of our long-term debt including any current portions included in our consolidated balance sheets.

In millions	Carrying amount (1)	Estimated fair value
As of December 31, 2007	$1,674	$1,710
As of December 31, 2006	1,633	1,716

(1) Includes $11 million of medium-term notes reported as short-term debt in our December 31, 2006, consolidated balance sheets.

The estimated fair values are determined based on interest rates that are currently available for issuance of debt with similar terms and remaining maturities. 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, 2007.

Risk Management

Our risk management activities are monitored by our Risk Management Committee (RMC). The RMC consists of members of senior management and is charged with reviewing and enforcing 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, interest rate, weather and foreign currency risks:

- forward contracts
- futures contracts
- options contracts
- financial swaps
- treasury locks
- weather derivative contracts
- storage and transportation capacity transactions
- foreign currency forward contracts

Interest Rate Swaps

To maintain an effective capital structure, our policy is to borrow funds using a mix of fixed-rate and variable-rate debt. We entered into interest rate swap agreements for the purpose of managing the appropriate mix of risk associated with our fixed-rate and variable-rate debt obligations. We designated these interest rate swaps as fair value hedges in accordance with SFAS 133. 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 interest rate risk being hedged.

As of December 31, 2007, a notional principal amount of $100 million of these interest rate swap agreements effectively converted the interest expense associated with a portion of our senior notes from fixed rates to variable rates based on an interest rate equal to the LIBOR plus a 3.4% spread. The floating rate for our interest rate swap as of December 31, 2007 was 8.8% and was 9.0% as of December 31, 2006. The fair values of our interest rate swaps were reflected as a long-term liability of $2 million at December 31, 2007, and $6 million at December 31, 2006. For more information on our senior notes, see Note 6.

Treasury Locks

In August 2007, we executed a treasury-lock agreement covering a notional amount totaling $125 million to hedge the interest rate risk associated with our $125 million senior notes offering in December 2007. The 10-year treasury interest rate was locked in at a weighted average rate of 4.5%.

In December 2007, this treasury-lock agreement settled and we paid $5 million with our $125 million senior note issuance. The $5 million is included in our OCI, net of $2 million of income taxes, and will be amortized over the remaining life of the senior notes (through July 2016) as interest expense.

Commodity-related Derivative Instruments

Elizabethtown Gas In accordance with a directive from the New Jersey Commission, Elizabethtown Gas enters into derivative transactions to hedge the impact of market fluctuations in natural gas prices. Pursuant to SFAS 133, such derivative transactions are marked to market each reporting period. In accordance with regulatory requirements, realized gains and losses related to these derivatives are reflected in purchased gas costs and ultimately included in billings to customers. As of December 31, 2007, Elizabethtown Gas had entered into NYMEX futures contracts to purchase approximately 1.2 Bcf of natural gas and over the counter swap contracts with 3 counterparties to purchase approximately 8.1 Bcf of natural gas. Approximately 84% of these contracts have durations of one year or less, and none of these contracts extends beyond October 2009. The fair values of these derivative instruments were reflected as a current asset and liability of $4 million at December 31, 2007 and $16 million at December 31, 2006. For more information on our regulatory assets and liabilities see Note 1.

SouthStar Commodity-related derivative financial instruments (futures, options and swaps) are used by SouthStar to manage exposures arising from changing commodity prices. SouthStar's objective for holding these derivatives is to utilize the most effective method to reduce or eliminate the impact of this exposure. We have designated a portion of SouthStar's derivative transactions as cash flow hedges under SFAS 133. We record derivative gains or losses arising from cash flow hedges in OCI and reclassify them into earnings in the same period as the settlement of the underlying hedged item. We record any hedge ineffectiveness, defined as when the gains or losses on the hedging instrument do not offset and are greater than the losses or gains on the hedged item, in cost of gas in our statement of consolidated income in the period in which it occurs. SouthStar currently has minimal hedge ineffectiveness. We have not designated the remainder of SouthStar's derivative instruments as hedges under SFAS 133 and, accordingly, we record changes in their fair value in earnings in the period of change.

At December 31, 2007, the fair values of these derivatives were reflected in our consolidated financial statements as a current asset of $12 million and a current liability of $2 million representing a net position of 0.1 Bcf.

SouthStar also enters into both exchange and over-the-counter derivative transactions to hedge commodity price risk. Credit risk is mitigated for exchange transactions through the backing of the NYMEX member firms. For over-the-counter transactions, SouthStar utilizes master netting arrangements to reduce overall credit risk. As of December 31, 2007, SouthStar's maximum exposure to any single over-the-counter counterparty was $14 million.

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 use.

We mitigate substantially all the commodity price risk associated with Sequent's natural gas portfolio by locking in the economic margin at the time we enter into natural gas purchase transactions for our stored natural gas. We purchase natural gas for storage when the difference in the current market price we pay to buy and transport natural gas plus the cost to store the natural gas is less than the market price we can receive in the future, resulting in a positive net operating margin. We use NYMEX futures contracts and other over-the-counter derivatives to sell natural gas at that future price to substantially lock in the operating margin we will ultimately realize when the stored natural gas is actually sold. These futures contracts meet the definition of derivatives under SFAS 133 and are recorded at fair value and marked to market in our consolidated balance sheets, with changes in fair value recorded in earnings in the period of change. The purchase, transportation, storage and sale of natural gas are accounted for on a weighted average cost or accrual basis, as appropriate 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 can result in volatility in our reported earnings, even though the economic margin is essentially unchanged from the date the transactions were consummated.

At December 31, 2007, Sequent's commodity-related derivative financial instruments represented purchases (long) of 605 Bcf and sales (short) of 576 Bcf with approximately 91% of purchase instruments and 93% of the sales instruments are scheduled to mature in less than 2 years and the remaining 9% and 7%, respectively, in 3 to 9 years. At December 31, 2007, the fair values of these derivatives were reflected in our consolidated financial statements as an asset of $70 million and a liability of $13 million. Sequent recorded net unrealized losses related to changes in the fair value of derivative instruments utilized in its energy marketing and risk management activities and contract settlement of $62 million during 2007, $132 million of unrealized gains during 2006 and $30 million of unrealized losses during 2005.

Weather Derivatives

In 2007 and 2006, SouthStar entered into weather derivative contracts as economic hedges of operating margins in the event of warmer-than-normal weather in the heating season, primarily from November through March. SouthStar accounts for these contracts using the intrinsic value method under the guidelines of EITF 99-02. SouthStar recorded current assets for this hedging activity of $5 million at December 31, 2007 and $7 million at December 31, 2006.

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 12 Marketers in Georgia. The credit risk exposure to Marketers varies seasonally, with the lowest exposure in the nonpeak summer months and the 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 month's estimated bill from Atlanta Gas Light.

Wholesale Services Sequent has a concentration of credit risk for services it provides to marketers and to utility and industrial counterparties. This credit risk is measured by 30-day receivable exposure plus forward exposure, which is generally concentrated in 20 of its counterparties. Sequent evaluates the credit risk of its counterparties using a S&P equivalent credit rating, which is determined by a process of converting the lower of the S&P or 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. For a customer without an external rating, Sequent assigns an internal rating based on Sequent's analysis of the strength of its financial ratios. At December 31, 2007, Sequent's top 20 counterparties represented approximately 53% of the total credit exposure of $366 million, derived by adding together 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 rating of A- at December 31, 2007.

The weighted average credit rating is obtained by multiplying each customer's assigned internal rating by its credit exposure and then adding the individual results for all counterparties. That total is divided by the aggregate total exposure. This numeric value is converted to an S&P equivalent.

Sequent has established credit policies to determine and monitor the creditworthiness of counterparties, including requirements for posting of collateral or other credit security, as well as the quality of pledged collateral. Collateral or credit security is most often in the form of cash or letters of credit from an investment-grade financial institution, but may also include cash or U.S. Government Securities held by a trustee. When Sequent is engaged in more than one outstanding derivative transaction with the same counterparty and it also has a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of Sequent's credit risk. Sequent also uses other netting agreements with certain counterparties with which it conducts significant transactions.

All activities associated with price risk management activities and derivative instruments are included as a component of cash flows from operating activities in our consolidated statements of cash flows. Our derivatives not designated as hedges under SFAS 133, included within operating cash flows as a source (use) of cash was $62 million in 2007, $(132) million in 2006, and $30 million in 2005.

Note 3 - Employee Benefit Plans

Pension Benefits

We sponsor two tax-qualified defined benefit retirement plans for our eligible employees, the AGL Resources Inc. Retirement Plan (AGL Retirement Plan) and the Employees' Retirement Plan of NUI Corporation (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 AGL Retirement Plan is a career average earnings formula, except for participants who were employees as of July 1, 2000, and who were at least 50 years of age as of that date. For those participants, we use a final average earnings benefit formula, and will continue to use this benefit formula for such participants until June 2010, at which time any of those participants who are still active will accrue future benefits under the career average earnings formula.

The NUI Retirement Plan covers substantially all of NUI's employees who were employed on or before December 31, 2005, except Florida City Gas union employees, who participate in a union-sponsored multiemployer plan. Pension benefits are based on years of credited service and final average compensation.

Effective with our acquisition of NUI in November 2004, we became sponsor of the NUI Retirement Plan. Throughout 2005, we maintained existing benefits for NUI employees, including participation in the NUI Retirement Plan. Beginning in 2006, eligible participants in the NUI Retirement Plan became eligible to participate in the AGL Retirement Plan and the benefits of those participants under the NUI Retirement Plan were frozen as of December 31, 2005, resulting in a $15 million reduction to the NUI Retirement Plan's projected benefit obligation as of December 31, 2005. Participants in the NUI Retirement Plan have the option of receiving a lump sum distribution upon retirement for all benefits earned through December 31, 2005. This resulted in settlement payments of $12 million and an immaterial settlement loss. This option is not permitted under the AGL Retirement Plan, except for accrued benefits valued at less than $10,000.

SFAS 158 In September 2006, the FASB issued SFAS 158, which we adopted prospectively on December 31, 2006. SFAS 158 requires that we recognize all obligations related to defined benefit pensions and other postretirement benefits. This statement requires that we quantify the plans' funding status as an asset or a liability on our consolidated balance sheets.

SFAS 158 further requires that we measure the plans' assets and obligations that determine our funded status as of the end of the fiscal year. We are also required to recognize as a component of OCI the changes in funded status that occurred during the year that are not recognized as part of net periodic benefit cost as explained in SFAS 87, or SFAS 106.

Based on the funded status of our defined benefit pension and postretirement benefit plans as of December 31, 2007, we reported a gain to our OCI of $24 million, a net decrease of $40 million to accrued pension and postretirement obligations and an increase of $16 million to accumulated deferred income taxes. Our adoption of SFAS 158 on December 31, 2006, had no impact on our earnings. The following tables present details about our pension plans.

In millions	AGL Retirement Plan Dec. 31, 2007	AGL Retirement Plan Dec. 31, 2006	NUI Retirement Plan Dec. 31, 2007	NUI Retirement Plan Dec. 31, 2006
Change in benefit obligation				
Benefit obligation at beginning of year	$368	$359	$86	$105
Service cost	7	7	-	-
Interest cost	21	20	5	5
Settlement loss	-	-	-	1
Settlement payments	-	-	-	(12)
Actuarial loss (gain)	(23)	2	(9)	(7)
Benefits paid	(20)	(20)	(8)	(6)
Benefit obligation at end of year	$353	$368	$74	$86
Change in plan assets				
Fair value of plan assets at beginning of year	$303	$286	$72	$85
Actual return on plan assets	30	31	6	4
Employer contribution	-	6	-	1
Settlement payments	-	-	-	(12)
Benefits paid	(20)	(20)	(8)	(6)
Fair value of plan assets at end of year	$313	$303	$70	$72
Amounts recognized in the statement of financial position consist of				
Prepaid benefit cost	$-	$-	$-	$-
Accrued benefit liability	(40)	(65)	(4)	(14)
Accumulated OCI	-	-	-	-
Net amount recognized at year end (1)	$(40)	$(65)	$(4)	$(14)

(1) As of December 31, 2007, the AGL Retirement Plan had current liabilities of $1 million, noncurrent liabilities of $39 million and no noncurrent assets. The NUI Retirement Plan had $4 million of noncurrent liabilities and no noncurrent assets or current liabilities. As of December 31, 2006, the AGL Retirement Plan had current liabilities of $1 million, non-current liabilities of $64 million and no non-current assets. The NUI Retirement Plan had $14 million of non-current liabilities and non-current assets or current liabilities as of December 31, 2006.

The accumulated benefit obligation (ABO) and other information for the AGL Retirement Plan and the NUI Retirement Plan are set forth in the following table.

In millions	AGL Retirement Plan Dec. 31, 2007	AGL Retirement Plan Dec. 31, 2006	NUI Retirement Plan Dec. 31, 2007	NUI Retirement Plan Dec. 31, 2006
Projected benefit obligation	$353	$368	$74	$86
ABO	337	352	74	86
Fair value of plan assets	313	303	70	72
Increase in minimum liability included in OCI	n/a	13	n/a	-
Components of net periodic benefit cost				
Service cost	$7	$7	$-	$-
Interest cost	21	20	5	5
Expected return on plan assets	(25)	(24)	(6)	(7)
Net amortization	(1)	(1)	(1)	(1)
Recognized actuarial loss	7	9	-	-
Net annual pension cost	$9	$11	$(2)	$(3)

There were no other changes in plan assets and benefit obligations recognized for the AGL and NUI Retirement Plans for the year ended December 31, 2007.

The 2008 estimated OCI amortization and expected refunds for the AGL and NUI Retirement Plans are set forth in the following table.

In millions	Retirement Plan AGL	Retirement Plan NUI
Amortization of transition obligation	$-	$-
Amortization of prior service cost	(1)	(1)
Amortization of net loss	3	-
Refunds expected	-	-

The following table sets forth the assumed weighted average discount rates and rates of compensation increase used to determine benefit obligations at December 31.

	AGL and NUI Retirement Plans	
	2007	2006
Discount rate	6.4%	5.8%
Rate of compensation increase	3.7%	4.0%

We consider a number of factors in determining and selecting assumptions for 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, and 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.

The following tables present the assumed weighted average discount rate, expected return on plan assets and rate of compensation increase used to determine net periodic benefit cost at the beginning of the period, which was January 1.

	AGL Retirement Plan		
	2007	2006	2005
Discount rate	5.8%	5.5%	5.8%
Expected return on plan assets	9.0%	8.8%	8.8%
Rate of compensation increase	3.7%	4.0%	4.0%

	NUI Retirement Plan		
	2007	2006	2005
Discount rate	5.8%	5.5%	5.8%
Expected return on plan assets	9.0%	8.8%	8.5%
Rate of compensation increase	-%	-%	4.0%

We consider a variety of factors in determining and selecting our assumptions for the discount rate at December 31. We consider certain market indices, including Moody's Corporate AA long-term bond rate, the Citigroup Pension Liability rate our actuaries model and our own payment stream based on these indices to develop our rate. Consequently, we selected a discount rate of 6.4% as of December 31, 2007, following our review of these various factors.

Our actual retirement plans' weighted average asset allocations at December 31, 2007 and 2006 and our target asset allocation ranges are as follows:

	Target Range Asset Allocation	AGL Retirement Plan 2007	2006
Equity	30%-80%	68%	67%
Fixed income	10%-40%	25%	25%
Real estate and other	10%-35%	3%	8%
Cash	0%-10%	4%	-

	Target Range Asset Allocation	NUI Retirement Plan 2007	2006
Equity	30%-80%	71%	68%
Fixed income	10%-40%	27%	26%
Real estate and other	10%-35%	2%	3%
Cash	0%-10%	-%	3%

The Retirement Plan Investment Committee (the Committee) appointed by our Board of Directors is responsible for overseeing the investments of the retirement plans. Further, we have an Investment Policy (the Policy) for the retirement plans that aims to preserve the retirement plans' capital and maximize investment earnings in excess of inflation within acceptable levels of capital market volatility. To accomplish this goal, the retirement plans' assets are actively managed to optimize 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 diversify retirement plan investments 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 preceding tables, but the Committee can vary allocations between various classes or investment managers in order to improve 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 difference 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 plans. We fund the plans by contributing at least the minimum amount required by applicable regulations and as recommended by our actuary. However, we may also contribute in excess of the minimum required amount. We calculate the minimum amount of funding using the projected unit credit cost method. The Pension Protection Act (the Act) of 2006 contains new funding requirements for single employer defined benefit pension plans. The Act establishes a 100% funding target for plan years beginning after December 31, 2007. However, a delayed effective date of 2011 may apply if the pension plan meets the following targets: 92% funded in 2008; 94% funded in 2009; and 96% funded in 2010. In October 2006 we made a voluntary contribution of $5 million to the AGL Resources Inc. Retirement Plan. No contribution was required for the qualified plans in 2007, and we did not make a contribution. Further, no contribution is required for the qualified plans in 2008.

Postretirement Benefits

Until January 1, 2006, we sponsored 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), which we acquired upon our acquisition of NUI. Eligibility for these benefits is based on age and years of service.

The NUI Postretirement Plan provided certain medical and dental health care benefits to retirees, other than retirees of Florida City Gas, depending on their age, years of service and start date. The NUI Postretirement Plan was contributory, and NUI funded a portion of these future benefits through a Voluntary Employees' Beneficiary Association. Effective July 2000, NUI no longer offered postretirement benefits other than pension 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. At the beginning of 2006, eligible participants in the NUI Postretirement Plan became eligible to participate in the AGL Postretirement Plan and all participation in this plan ceased, effective January 1, 2006.

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. 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 for these future recoveries of $12 million as of December 31, 2007 and $13 million as of December 31, 2006. In addition, we recorded a regulatory liability of $4 million as of December 31, 2007 and $4 million as of December 31, 2006 for our expected expenses under the AGL Postretirement Plan. We expect to pay $7 million of insurance claims for the postretirement plan in 2008, but we do not anticipate making any additional contributions.

Effective December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 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.

On July 1, 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 through some period of time. Medicare-eligible participants receive prescription drug benefits through a Medicare Part D plan offered by a third party and to which AGL subsidizes participant premiums. Medicare-eligible retirees who opt out of the AGL Postretirement Plan are eligible to receive a cash subsidy which may be used towards eligible prescription drug expenses. The following tables present details about our postretirement benefits.

	AGL Postretirement Plan	
In millions	Dec. 31, 2007	Dec. 31, 2006
Change in benefit obligation		
Benefit obligation at beginning of year	$95	$107
Service cost	1	1
Interest cost	6	5
Actuarial (gain) loss	-	(9)
Benefits paid	(8)	(9)
Benefit obligation at end of year	$94	$95
Change in plan assets		
Fair value of plan assets at beginning of year	$63	$59
Actual return on plan assets	7	5
Employer contribution	8	8
Benefits paid	(8)	(9)
Fair value of plan assets at end of year	$70	$63
Amounts recognized in the statement of financial position consist of		
Prepaid benefit cost	$-	$-
Accrued benefit liability	(24)	(32)
Accumulated OCI	-	-
Net amount recognized at year end (1)	$(24)	$(32)

(1) As of December 31, 2007 and 2006, the AGL Postretirement Plan had $24 million and $32 million of noncurrent liabilities, respectively, and no noncurrent assets or current liabilities.

The following table presents details on the components of our net periodic benefit cost for the AGL Postretirement Plan at the balance sheet dates.

In millions	2007	2006
Service cost	$1	$1
Interest cost	6	5
Expected return on plan assets	(5)	(4)
Amortization of prior service cost	(4)	(4)
Recognized actuarial loss	1	1
Net periodic postretirement benefit cost	$(1)	$(1)

There were no other changes in plan assets and benefit obligations recognized for the AGL Postretirement Plan for the year ended December 31, 2007. The 2008 estimated OCI amortization and refunds expected for the AGL Postretirement Plan are set forth in the following table.

In millions	2008
Amortization of transition obligation	$-
Amortization of prior service cost	(4)
Amortization of net loss	-
Refunds expected	-

The following table sets forth the assumed weighted average discount rates and rates of compensation increase used to determine benefit obligations for the AGL postretirement plans at December 31.

	2007	2006 (1)
Discount rate	6.4%	5.8%
Rate of compensation increase	3.7%	4.0%

The following table presents our weighted average assumed rates used to determine benefit obligations at the beginning of the period, January 1 for the AGL Postretirement Plan and December 1 for the NUI Postretirement Plan, and our weighted average assumed rates used to determine net periodic benefit cost at the beginning of this same period.

	AGL Postretirement Plan			NUI Postretirement Plan
	2007	2006	2005	2005 (1)
Discount rate – benefit obligation	6.4%	5.8%	5.5%	5.5%
Discount rate – net periodic benefit cost	5.8%	5.5%	5.8%	5.8%
Expected return on plan assets	9.0%	8.5%	8.8%	3.0%
Rate of compensation increase	3.7%	4.0%	4.0%	-

(1) The NUI postretirement plan was terminated and eligible former participants became eligible to participate in the AGL postretirement plan on January 1, 2006.

For information on the discount rate assumptions used for our postretirement plans, see the discussion contained in this Note 3 under the caption "Pension Benefits."

We consider the same factors in determining and selecting our assumptions for the overall expected long-term rate of return on plan assets as those considered in determining and selecting the overall expected long-term rate of return on plan assets for our retirement plans. For purposes of measuring our accumulated postretirement benefit obligation, the assumed pre-Medicare and post-Medicare health care inflation rates are as follows:

	AGL Postretirement Plan			
	Pre-medicare cost (pre-65 years old)		Post-medicare cost (post-65 years old)	
Assumed health care cost trend rates at December 31,	2007	2006	2007	2006
Health care costs trend rate assumed for next year	2.5%	2.5%	2.5%	2.5%
Rate to which the cost trend rate gradually declines	2.5%	2.5%	2.5%	2.5%
Year that the rate reaches the ultimate trend rate	N/A	N/A	N/A	N/A

Effective January 2006, our health care trend rates for the AGL Postretirement Plan was capped at 2.5%. This cap limits the increase in our contributions to the annual change in the consumer price index (CPI). An annual CPI rate of 2.5% was assumed for future years.

Assumed health care cost trend rates impact 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 for the AGL Postretirement Plan and the NUI Postretirement Plan.

	AGL Postretirement Plan One-Percentage-Point	
In millions	Increase	Decrease
Effect on total of service and interest cost	$-	$-
Effect on accumulated postretirement benefit obligation	4	(4)

Our investment policies and strategies for our postretirement plans, including target allocation ranges, are similar to those for our retirement plans. We fund the plans annually; retirees contribute 20% of medical premiums, 50% of the medical premium for spousal coverage and 100% of the dental premium. Our postretirement plans weighted average asset allocations for 2007 and 2006 and our target asset allocation ranges are as follows.

In millions	Target Asset allocation ranges	2007	2006
Equity	30%-80%	73%	66%
Fixed income	10%-40%	26%	32%
Real estate and other	10%-35%	-%	-%
Cash	0%-10%	1%	2%

The following table presents expected benefit payments covering the periods 2008 through 2017 for our retirement plans and postretirement health care plans. There will be benefit payments under these plans beyond 2017.

For the years ended Dec. 31, *(in millions)*	AGL Retirement Plan	NUI Retirement Plan	AGL Postretirement Plan
2008	$20	$6	$7
2009	20	6	7
2010	20	6	7
2011	20	6	7
2012	21	6	7
2013-2017	116	29	36

The following table presents the amounts not yet reflected in net periodic benefit cost and included in accumulated OCI as of December 31, 2007.

In millions	AGL Retirement Plan	NUI Retirement Plan	AGL Postretirement Plan
Transition obligation	$-	$-	$1
Prior service credit	(8)	(13)	(21)
Net loss (gain)	70	(7)	13
Accumulated OCI	62	(20)	(7)
Net amount recognized in statement of financial position.	(40)	(4)	(24)
Cumulative employer contributions in excess of net periodic benefit cost (accrued) prepaid	$22	$(24)	$(31)

There were no other changes in plan assets and benefit obligations recognized in the AGL and NUI Retirement Plans or the AGL Postretirement Plan for the year ended December 31, 2007.

Employee Savings Plan Benefits

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

- $6 million in 2007
- $6 million in 2006
- $5 million in 2005

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 have not been significant in any year.

Note 4 - Stock-based and Other Incentive Compensation Plans and Agreements

General

We currently sponsor the following stock-based and other incentive compensation plans and agreements:

	Shares issuable upon exercise of outstanding stock options and / or SARs (1)	Shares issuable and / or SARs available for issuance (1)	Details
2007 Omnibus Performance Incentive Plan	44,500	4,806,086	Grants of incentive and nonqualified stock options, stock appreciation rights (SARs), shares of restricted stock, restricted stock units and performance cash awards to key employees.
Long-Term Incentive Plan (1999) (2)	2,249,812	-	Grants of incentive and nonqualified stock options, shares of restricted stock and performance units to key employees.
Long-Term Stock Incentive Plan of 1990 (3)	91,061	-	Grants of incentive and nonqualified stock options, SARs and shares of restricted stock to key employees.
Officer Incentive Plan	87,064	215,702	Grants of nonqualified stock options and shares of restricted stock to new-hire officers.
2006 Non-Employee Directors Equity Compensation Plan	not applicable	189,107	Grants of stock to non-employee directors in connection with non-employee director compensation (for annual retainer, chair retainer and for initial election or appointment).
1996 Non-Employee Directors Equity Compensation Plan	45,061	14,180	Grants of nonqualified stock options and stock to non-employee directors in connection with non-employee director compensation (for annual retainer and for initial election or appointment). The plan was amended in 2002 to eliminate the granting of stock options.
Employee Stock Purchase Plan	not applicable	388,159	Nonqualified, broad-based employee stock purchase plan for eligible employees
Stand-alone SARs	2,761	-	Represents SARs that have been granted to key employees under individual agreements and are settled in cash.

(1) As of December 31, 2007
(2) Following shareholder approval of the Omnibus Performance Incentive Plan, no further grants will be made except for reload options that may be granted under the plan's outstanding options.
(3) Following shareholder approval of the Long-Term Incentive Plan (1999), no further grants will be made except for reload options that may be granted under the plan's outstanding options.

Accounting Treatment and Compensation Expense

Effective January 1, 2006, we adopted SFAS 123R, using the modified prospective application transition method. Financial results for the prior periods presented were not retroactively adjusted to reflect the effects of SFAS 123R.

Prior to January 1, 2006, we accounted for our share-based payment transactions in accordance with SFAS 123, as amended by SFAS 148. This allowed us to rely on APB 25 and related interpretations in accounting for our stock-based compensation plans under the intrinsic value method. SFAS 123R requires us to measure and recognize stock-based compensation expense in our financial statements based on the estimated fair value at the date of grant for our stock-based awards, which include:

- stock options
- stock awards, and
- performance units (restricted stock units and performance cash units)

Performance-based stock awards and performance units contain market conditions. Stock options, restricted stock awards and performance units also contain a service condition. In accordance with SFAS 123R, we recognize compensation expense over the requisite service period for:

- awards granted on or after January 1, 2006 and
- unvested awards previously granted and outstanding as of January 1, 2006

In addition, we estimate forfeitures over the requisite service period when recognizing compensation expense. These estimates are adjusted to the extent that actual forfeitures differ, or are expected to materially differ, from such estimates.

In 2005, we did not record compensation expense related to our stock option grants in our financial statements, which is consistent with the APB 25 requirements. However, at the end of each reporting period, we recorded compensation expense over the requisite service period for our other stock-based and performance cash unit awards. The following table provides additional information on compensation costs and income tax benefits related to our stock-based compensation awards. We recorded these amounts in our consolidated statements of income for the years ended December 31, 2007, 2006 and 2005.

In millions	2007	2006	2005
Compensation costs	$9	$9	$5
Income tax benefits	3	3	8

Prior to our adoption of SFAS 123R, benefits of tax deductions in excess of recognized compensation costs were reported as operating cash flows. SFAS 123R requires excess tax benefits to be reported as a financing cash inflow rather than as a reduction of taxes paid. In 2007 and 2006, our cash flows from financing activities included an immaterial amount for recognized compensation costs in excess of the benefits of tax deductions. In 2005, we included $8 million of such benefits in cash flow provided by operating activities.

If stock-based compensation expense for the year ended December 31, 2005 had been recorded based on the fair value of the awards at the grant dates consistent with the method prescribed by SFAS 123, which has been superseded by SFAS 123R, our net income and earnings per share for the year ended December 31, 2005 would have been reduced to the amounts shown in the following table.

In millions, except per share amounts	2005
Net income, as reported	$193
Deduct: Total stock-based employee compensation expense determined under fair value-based method for all awards, net of related tax effect	1
Pro-forma net income	$192
Earnings per share:	
Basic – as reported	$2.50
Basic – pro-forma	$2.48
Diluted – as reported	$2.48
Diluted – pro-forma	$2.47

Incentive and Nonqualified Stock Options

We grant incentive and nonqualified stock options with a strike price equal to the fair market value on the date of the grant. “Fair market value” is defined under the terms of the applicable plans as the most recent closing price per share of AGL Resources common stock as reported in *The Wall Street Journal*. Stock options generally have a three-year vesting period. Nonqualified options generally expire 10 years after the date of grant. Participants realize value from option grants only to the extent that the fair market value of our common stock on the date of exercise of the option exceeds the fair market value of the common stock on the date of the grant. Compensation expense associated with stock options is generally recorded over the option vesting period; however, for unvested options that are granted to employees who are retirement-eligible, the remaining compensation expense is recorded in the current period rather than over the remaining vesting period.

As of December 31, 2007, we had $4 million of total unrecognized compensation costs related to stock options. These costs are expected to be recognized over the remaining average requisite service period of approximately 2 years. Cash received from stock option exercises for 2007 was $10 million, and the income tax benefit from stock option exercises was $3 million. The following tables summarize activity related to stock options for key employees and non-employee directors.

Stock Options

	Number of options	Weighted average exercise price	Weighted average remaining life (in years)	Aggregate intrinsic value (in millions)
Outstanding – December 31, 2004	2,174,072	$23.23		
Granted	1,014,121	33.80		
Exercised	(846,465)	22.60		
Forfeited	(120,483)	32.38		
Outstanding – December 31, 2005	2,221,245	$27.79		
Granted	914,216	35.81		
Exercised	(543,557)	24.69		
Forfeited	(266,418)	34.93		
Outstanding – December 31, 2006	2,325,486	$30.85	7.2	
Granted	735,196	39.11	9.1	
Exercised	(361,385)	27.78	5.1	
Forfeited	(181,799)	36.75	8.3	
Outstanding – December 31, 2007	2,517,498	$33.28	7.1	$12
Exercisable – December 31, 2007	1,102,536	$28.48	5.4	$10

Unvested Stock Options

	Number of unvested options	Weighted average exercise price	Weighted average remaining vesting period (in years)	Weighted average fair value
Outstanding – December 31, 2006	1,311,814	$35.03	1.8	$4.75
Granted	735,196	39.11	2.1	4.90
Forfeited	(181,799)	36.75	1.3	4.88
Vested	(450,249)	34.73	-	4.73
Outstanding – December 31, 2007	1,414,962	$37.02	1.6	$4.82

Information about outstanding and exercisable options as of December 31, 2007, 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
$16.25 to $20.85	84,399	1.5	$19.98	84,399	$19.98
$20.86 to $25.45	275,719	3.4	21.65	275,719	21.65
$25.46 to $30.05	251,357	5.4	27.06	251,357	27.06
$30.06 to $34.65	441,047	7.0	33.20	270,609	33.17
$34.66 to $39.25	1,408,591	8.5	37.17	212,367	35.93
$39.26 to $43.85	56,385	8.6	41.29	8,085	41.14
Outstanding - Dec. 31, 2007	2,517,498	7.1	$33.28	1,102,536	$28.48

Summarized below are outstanding options that are fully exercisable.

Exercisable at:	Number of options	Weighted average exercise price
December 31, 2005	1,275,689	$23.46
December 31, 2006	1,013,672	$25.45
December 31, 2007	1,102,536	$28.48

In accordance with the fair value method of determining compensation expense, we use the Black-Scholes pricing model. Below are the ranges for per share value and information about the underlying assumptions used in developing the grant date value for each of the grants made during 2007, 2006 and 2005.

	2007	2006	2005
Expected life (years)	7	7	7
Risk-free interest rate % (1)	3.87 – 5.05	4.5 – 5.1	3.9 – 4.5
Expected volatility % (2)	13.2 – 14.3	14.2 – 15.9	17.1 – 17.3
Dividend yield % (3)	3.8 – 4.2	3.7 – 4.2	3.2 – 3.8
Fair value of options granted (4)	$3.55 – $5.98	$4.55– $6.18	$4.57 – $6.01

(1) US Treasury constant maturity - 7 years
(2) Volatility is measured over 7 years, the expected life of the options; weighted average volatility %'s for 2007 was 14.2%, 2006 was 15.8% and in 2005 was 17.3%.
(3) Weighted average dividend yields for 2007 was 4.2%, 2006 was 4.1% and in 2005 was 3.7%
(4) Represents per share value.

Intrinsic value for options is defined as the difference between the current market value and the grant price. Total intrinsic value of options exercised during 2007 was $5 million. With the implementation of our share repurchase program in 2006, we use shares purchased under this program to satisfy share-based exercises to the extent that repurchased shares are available. Otherwise, we issue new shares from our authorized common stock.

Performance Units

In general, a performance unit is an award of the right to receive (i) an equal number of shares of our common stock, which we refer to as a restricted stock unit or (ii) cash, subject to the achievement of certain pre-established performance criteria, which we refer to as a performance cash unit. Performance units are subject to certain transfer restrictions and forfeiture upon termination of employment. The dollar value of restricted stock unit awards is equal to the grant date fair value of the awards, over the requisite service period, determined pursuant to FAS 123R. The dollar value of performance cash unit awards is equal to the grant date fair value of the awards measured against progress towards the performance measure, over the requisite service period, determined pursuant to FAS 123R. No other assumptions are used to value these awards.

Restricted Stock Units In general, a restricted stock unit is an award that represents the opportunity to receive a specified number of shares of our common stock, subject to the achievement of certain pre-established performance criteria. In 2007, we granted to a select group a total of 127,400 restricted stock units (the 2007 restricted stock units), of which 113,700 of these units were outstanding as of December 31, 2007. These restricted stock units had a performance measurement period that ended December 31, 2007, and a performance measure related to a basic earnings per share goal. In February 2008, these restricted stock units were forfeited for failure to meet the performance criteria.

Performance Cash Units In general, a performance cash unit is an award that represents the opportunity to receive a cash award, subject to the achievement of certain pre-established performance criteria. In 2007, we granted performance cash awards to a select group of officers. These awards have a performance measure that is related to annual growth in basic earnings per share, plus the average dividend yield, as adjusted to reflect the effect of economic value created during the performance measurement period by our wholesale services segment. In 2007, the basic earnings per share growth target was not achieved with respect to the 2007 awards. Accruals in connection with these grants are as follows:

Dollars in millions	Units	Measurement period end date	Accrued at Dec. 31, 2007	Maximum aggregate payout
Year of grant				
2005 (1)	23	Dec. 31, 2007	$2	$3
2006	15	Dec. 31, 2008	1	2
2007	23	Dec. 31, 2009	-	3

(1) In February 2008, the 2005 performance cash units vested and resulted in an aggregate payout of $2 million.

Stock and Restricted Stock Awards

In general, we refer to a stock award as an award of our common stock that is 100% vested and not forfeitable as of the date of grant. We refer to restricted stock as an award of our common stock that is subject to time-based vesting or achievement of performance measures. Restricted stock awards are subject to certain transfer restrictions and forfeiture upon termination of employment. The dollar value of both stock awards and restricted stock awards are equal to the grant date fair value of the awards, over the requisite service period, determined pursuant to FAS 123R. No other assumptions are used to value the awards.

Stock Awards – ***Non-Employee Directors*** Non-employee director compensation may be paid in shares of our common stock in connection with initial election, the annual retainer, and chair retainers, as applicable. Stock awards for non-employee directors are 100% vested and nonforfeitable as of the date of grant. The following table summarizes activity during 2007, related to stock awards for our non-employee directors.

Restricted Stock Awards	Shares of restricted stock	Weighted average fair value
Issued	10,893	43.85
Forfeited	-	-
Vested	10,893	43.85
Outstanding	-	-

Restricted Stock Awards – ***Employees*** From time to time, we may give restricted stock awards to our key employees. The following table summarizes activity during the year ended December 31, 2007, related to restricted stock awards for our key employees.

Restricted Stock Awards	Shares of restricted stock	Weighted average remaining vesting period (in years)	Weighted average fair value
Outstanding – December 31, 2006 (1)	232,431	2.4	$35.49
Issued	224,649	2.4	39.72
Forfeited	(51,583)	1.3	36.55
Vested	(56,461)	-	34.93
Outstanding – December 31, 2007 (1)	349,036	2.1	$38.15

(1) Subject to restriction

Employee Stock Purchase Plan

Under the ESPP, employees may purchase shares of our common stock in quarterly intervals at 85% of fair market value. Employee contributions under the ESPP may not exceed $25,000 per employee during any calendar year.

	2007	2006	2005
Shares purchased on the open market	52,299	45,361	40,927
Average per-share purchase price	$34.69	$31.40	$30.52
Purchase price discount	$313,584	$252,752	$220,847

Stand-alone SARs

We recognize the intrinsic value of the SARs as compensation expense over the vesting period. Compensation expense for 2007, 2006 and 2005 was not material to our consolidated results of operations. A total of 2,761 SARs at a weighted average exercise price of $23.97 were vested and outstanding as of December 31, 2007.

Note 5 - Common Shareholders' Equity

Share Repurchases

In March 2001, our Board of Directors approved the purchase of up to 600,000 shares of our common stock to be used for issuances under the Officer Incentive Plan. In 2007, we purchased 10,667 shares under this plan. As of December 31, 2007, we had purchased a total 297,234 shares, leaving 302,766 shares available for purchase.

In February 2006, our Board of Directors authorized a plan to purchase up to 8 million shares of our outstanding common stock over a five-year period. These purchases are intended to offset share issuances under our employee and non-employee director incentive compensation plans and our dividend reinvestment and stock purchase plans. Stock purchases under this program may be made in the open market or in private transactions at times and in amounts that we deem appropriate. There is no guarantee as to the exact number of shares that we will purchase, and we can terminate or limit the program at any time. We will hold the purchased shares as treasury shares. As of December 31, 2007, we had repurchased 3,049,049 shares at a weighted average price of $38.58.

Dividends

We derive a substantial portion of our consolidated assets, earnings and cash flow from the operation of regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to us is subject to regulation. Our common shareholders may receive dividends when declared at the discretion of our Board of Directors. Dividends may be paid in cash, stock or other form of payment, and payment of future dividends will depend on our future earnings, cash flow, financial requirements and other factors, some of which are noted below. In certain cases, our ability to pay dividends to our common shareholders is limited by the following:

- our ability to satisfy our obligations under certain financing agreements, including debt-to-capitalization and total shareholders' equity covenants
- our ability to satisfy our obligations to any preferred shareholders

Note 6 - Debt

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, the SEC and the FERC as granted by the Energy Policy Act of 2005. The following table provides more information on our various securities.

In millions	Year(s) due	Interest rate (1)	Weighted average interest rate (1)	Outstanding as of December 31, 2007	2006
Short-term debt					
Commercial paper	2008	5.6%	5.4%	$566	$508
Pivotal Utility line of credit	2008	4.5	5.4	12	17
Sequent line of credit	2008	4.5	5.4	1	2
Capital leases	2008	4.9	4.9	1	1
Current portion of long-term debt	2008	-	-	-	11
Total short-term debt		**5.6%**	**5.4%**	**$580**	**$539**
Long-term debt - net of current portion					
Senior notes	2011-2034	4.5 – 7.1%	5.8%	$1,275	$1,150
Gas facility revenue bonds	2022-2033	3.8 – 5.3	4.3	199	199
Medium-term notes	2012-2027	6.6 – 9.1	7.8	196	196
Capital leases	2013	4.9	4.9	6	6
Notes payable to Trusts	-	-	-	-	77
AGL Capital interest rate swaps	2011	8.8	8.8	(2)	(6)
Total long-term debt		**6.0%**	**6.1%**	**$1,674**	**$1,622**
Total debt		**5.9%**	**5.9%**	**$2,254**	**$2,161**

(1) As of December 31, 2007.

Short-term Debt

Our short-term debt at December 31, 2007 and 2006 was composed of borrowings under our commercial paper program; current portions of our capital lease obligations and the current portion of our long-term medium-term notes; and lines of credit for Sequent and Pivotal Utility.

Commercial Paper Our commercial paper consists of short-term, unsecured promissory notes with maturities ranging from 2 to 46 days. These unsecured promissory notes are supported by our $1 billion Credit Facility which expires in August 2011. We have the option to increase the aggregate principal amount available for borrowing under the Credit Facility to $1.25 billion on not more than three occasions during each calendar year. As of December 31, 2007 or 2006 we did not have any amounts outstanding under the Credit Facility.

SouthStar Credit Facility SouthStar's five-year $75 million unsecured credit facility expires in November 2011. SouthStar will use this line of credit for working capital and its general corporate needs. On December 31, 2007 and 2006, there were no outstanding borrowings on this line of credit. We do not guarantee or provide any other form of security for the repayment of this credit facility.

Sequent Line of Credit In 2007, we extended Sequent's two lines of credit through June 2008 and August 2008. These unsecured lines of credit, which total $45 million and bear interest at the federal funds effective rate plus 0.4%, are used solely for the posting of margin deposits for NYMEX transactions and are unconditionally guaranteed by us.

Pivotal Utility Line of Credit In August 2007, we extended the Pivotal Utility $20 million line of credit through August 2008. This line of credit supports Elizabethtown Gas' hedging program and bears interest at the federal funds effective rate plus 0.4%, is used solely for the posting of deposits and is unconditionally guaranteed by us. For more information on Elizabethtown Gas' hedging program, see Note 2.

Long-term Debt

Our long-term debt at December 31, 2007 and 2006 matures more than one year from the balance sheet date 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:

Year	Amount (in millions)
2011	$300 (1)
2012	15
2013	230
2015	200
2016	300
2017	22
2021	30
2022	93
2024	20
2026	69
2027	54
2032	55
2033	40
2034	250
Total	$1,678 (2)

(1) Excludes the fair value of $2 million related to our interest rate swaps.
(2) Excludes $2 million of unamortized issuance costs related to our gas facility revenue bonds.

Medium-term notes The following table provides more information on our medium-term notes, which were issued to refinance portions of our existing short-term debt and for general corporate purposes. Our annual maturities of our medium-term notes are as follows:

Issue Date	Amount (in millions)	Interest rate	Maturity
June 1992	$5	8.4%	June 2012
June 1992	5	8.3	June 2012
June 1992	5	8.3	July 2012
July 1997	22	7.2	July 2017
Feb. 1991	30	9.1	Feb. 2021
April 1992	5	8.55	April 2022
April 1992	25	8.7	April 2022
April 1992	6	8.55	April 2022
May 1992	10	8.55	May 2022
Nov. 1996	30	6.55	Nov. 2026
July 1997	53	7.3	July 2027
Total	$196		

Senior Notes The following table provides more information on our senior notes, which were issued to refinance portions of our existing short-term and long-term debt, to finance acquisitions and for general corporate purposes.

Issue date	Amount (in millions)	Interest rate	Maturity
Feb. 2001 (1)	$300	7.125%	Jan 2011
July 2003	225	4.45	Apr 2013
Dec. 2004	200	4.95	Jan 2015
June 2006	175	6.375	Jul 2016
Dec. 2007	125	6.375	Jul 2016
Sep. 2004	250	6.0	Oct 2034
Total	$1,275		

(1) $100 million has been converted to a variable-rate obligation through an interest rate swap we entered into in March 2003. We pay a variable rate determined with a six-month LIBOR plus 3.4%, which was 8.8% at December 31, 2007 and 9.0% at December 31, 2006. The interest rate swap expires in January 2011.

In December 2007, we issued $125 million of senior notes which were part of a series originally issued by us in June 2006 in the amount of $175 million at an interest rate of 6.375%, for a total amount outstanding of $300 million at December 31, 2007. We used $123 million in net proceeds with the issuance to repay commercial paper.

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 of our senior notes.

Gas Facility Revenue Bonds Pivotal Utility is party to a series of loan agreements with the New Jersey Economic Development Authority (NJEDA) pursuant to which the NJEDA has issued a series of gas facility revenue bonds as shown in the following table. We do not guarantee or provide any other form of security for the repayment of this indebtedness.

Issue Date	Amount (in millions)	Interest rate	Maturity
July 1994 (1)	$47	3.8%	Oct. 2022
July 1994 (1)	20	4.9	Oct. 2024
June 1992 (1)	39	3.8	June 2026
June 1992 (1)	55	4.7	June 2032
July 1997	40	5.25	Nov. 2033
Unamortized issuance costs	(2)		
Total	$199		

(1) Interest rate is adjusted every 35 days. Rates indicated are as of December 31, 2007.

In June 2007, we refinanced $55 million of our gas facility revenue bonds due June 2032. The original bonds had a fixed interest rate of 5.7% per year and were refinanced with $55 million of adjustable-rate gas facility revenue bonds. The maturity date of these bonds remains June 2032. The bonds were issued at an initial annual interest rate of 3.8% and have a 35-day auction period where the interest rate will adjust every 35 days.

The variable bonds contain a provision whereby the holder can "put" the bonds back to the issuer. In 1996, Pivotal Utility executed a long-term Standby Bond Purchase Agreement (SBPA) with a syndicate of banks, which was amended and restated in June 2005. Under the terms of the SBPA, as further amended, the participating banks are 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 participating banks would remain in effect until the June 2010 expiration of the SBPA, unless it is extended or earlier terminated.

Notes Payable to Trusts In June 1997, we established AGL Capital Trust I (Trust I), a Delaware business trust, of which we own 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 were subject to mandatory redemption at the time of the repayment of the junior subordinated debentures in June 2037, or the optional prepayment by us after May 2007.

In July 2007, we used the proceeds from the sale of commercial paper to pay Trust I the $75 million principal amount plus a $3 million premium in connection with the early redemption of the junior subordinated debentures, and to pay the $2 million note with respect to our common securities interest in AGL Capital Trust I. The $3 million premium was recorded as interest expense in 2007.

Preferred Securities As of December 31, 2007, we had 10 million shares of authorized, unissued Class A junior participating preferred stock, no par value, and 10 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 City 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 City Gas is required to insure the leased equipment during the lease term. In addition, at the expiration of the lease term, Florida City Gas has the option to purchase the leased meters from the lessor at their fair market value.

Default Events

Our Credit Facility financial covenant requires us to maintain a ratio of total debt to total capitalization of no greater than 70%. As of December 31, 2007, this ratio was 58% and was 57% as of December 31, 2006. 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
- 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 7 - Commitments and Contingencies

We have incurred various contractual obligations and financial commitments in the normal course of our operating and financing activities that are reasonably likely to have a material affect on liquidity or the availability of requirements for capital resources. 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. The following table illustrates our expected future contractual payments such as debt and lease agreements, and commitment and contingencies as of December 31, 2007.

In millions	Total	2008	2009 & 2010	2011 & 2012	2013 & thereafter
Recorded contractual obligations:					
Long-term debt	$1,674	$-	$2	$315	$1,357
Short-term debt	580	580	-	-	-
ERC (1)	107	10	34	53	10
PRP costs (1)	245	55	112	60	18
Total	$2,606	$645	$148	$428	$1,385

(1) Includes charges recoverable through rate rider mechanisms

In millions	Total	2008	2009 & 2010	2011 & 2012	2013 & thereafter
Unrecorded contractual obligations and commitments (1):					
Interest charges (2)	$1,176	$100	$200	$157	$719
Pipeline charges, storage capacity and gas supply (3)	1,792	456	637	348	351
Operating leases (4)	154	26	50	34	44
Standby letters of credit, performance/ surety bonds	30	24	6	-	-
Asset management agreements (5)	24	8	8	8	-
Total	$3,176	$614	$901	$547	$1,114

(1) In accordance with generally accepted accounting principles, these items are not reflected in our consolidated balance sheet

(2) Floating rate debt is based on the interest rate as of December 31, 2007 and the maturity of the underlying debt instrument. As of December 31, 2007, we have $39 million of accrued interest on our consolidated balance sheet that will be paid in 2008.

(3) Charges recoverable through a PGA mechanism or alternatively billed to Marketers. Also includes demand charges associated with Sequent. SouthStar also includes gas commodity purchase commitments of 1.3 Bcf at floating gas prices calculated using forward natural gas prices as of December 31, 2007, and valued at $98 million.

(4) We have certain operating leases with provisions for step rent or escalation payments and certain lease concessions. We account for these leases by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms, in accordance with SFAS 13. However, this lease accounting treatment does not affect the future annual operating lease cash obligations as shown herein.

(5) Represent fixed-fee payments for Sequent's asset management agreements between Atlanta Gas Light ($4 million) and Elizabethtown Gas ($4 million). As of December 31, 2007, we have $1 million of accrued payments on our consolidated balance sheet, which will be paid in 2008.

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 10 former Atlanta Gas Light operating sites in Georgia and at 3 sites of predecessor companies in Florida. Atlanta Gas Light has active environmental remediation or monitoring programs in effect at 10 of these sites. Two sites in Florida are currently in the investigation or preliminary engineering design phase, and one Georgia site has been deemed compliant with state standards.

Atlanta Gas Light has customarily 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 better able to provide conventional engineering estimates of the likely costs of remediation at its former sites. These estimates contain various engineering uncertainties, but Atlanta Gas Light continuously attempts to refine and update these engineering estimates.

Atlanta Gas Light's current estimate for the remaining cost of future actions at its former operating sites is $35 million, which may change depending on whether future measures for groundwater will be required. As of December 31, 2007, we have recorded a liability equal to the low end of that range of $35 million, of which $6 million is expected to be incurred over the next 12 months.

These liabilities do 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 for which it cannot reasonably estimate an amount.

The ERC liability is included as a corresponding regulatory asset, which is a combination of accrued ERC 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 ERC recovery rider. The ERC 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 $21 million in revenues over the next 12 months under the ERC recovery rider, which is reflected as a current asset. The amounts recovered from the ERC recovery rider during the last three years were:

- $26 million in 2007
- $29 million in 2006
- $28 million in 2005

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 2007, 2006 or 2005.

The third way to recover costs is from the receipt of net profits from the sale of remediated property.

Elizabethtown Gas In New Jersey, Elizabethtown Gas is currently conducting remediation activities with oversight from the New Jersey Department of Environmental Protection. Although we cannot estimate the actual total cost of future environmental investigation and remediation efforts with precision, based on probabilistic models similar to those used at Atlanta Gas Light's former operating sites, the range of reasonably probable costs is $61 million to $119 million. As of December 31, 2007, we have recorded a liability equal to the low end of that range, or $61 million, of which $4 million in expenditures are expected to be incurred over the next 12 months.

Prudently incurred remediation costs for the New Jersey properties have been authorized by the New Jersey Commission to be recoverable in rates through a remediation adjustment clause. As a result, Elizabethtown Gas has recorded a regulatory asset of approximately $66 million, inclusive of interest, as of December 31, 2007, reflecting the future recovery of both incurred costs and accrued carrying charges. Elizabethtown Gas expects to collect $1 million in revenues over the next 12 months. 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.

We own a former NUI remediation site in Elizabeth City, North Carolina that is subject to a remediation order by the North Carolina Department of Energy and Natural Resources. We had recorded liabilities of $11 million and $10 million as of December 31, 2007 and 2006, respectively, related to this site.

There is one other site in North Carolina where investigation and remediation is likely, although no remediation 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, and accordingly we have not accrued any remediation liability. There are currently no cost recovery mechanisms for the environmental remediation sites in North Carolina.

Rental Expense

We incurred rental expense in the amounts of $21 million in 2007, $19 million in 2006 and $25 million in 2005.

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.

In August 2006, the Office of Mineral Resources of the Louisiana DNR informed Jefferson Island that its mineral lease – which authorizes salt extraction to create two new storage caverns – at Lake Peigneur had been terminated. The Louisiana DNR identified two bases for the termination: (1) failure to make certain mining leasehold payments in a timely manner, and (2) the absence of salt mining operations for six months.

In September 2006, Jefferson Island filed suit against the State of Louisiana to maintain its lease to complete an ongoing natural gas storage expansion project in Louisiana. The project would add two salt dome storage caverns under Lake Peigneur to the two caverns currently owned and operated by Jefferson Island. In its suit, Jefferson Island alleges that the Louisiana DNR accepted all leasehold payments without reservation and never provided Jefferson Island with notice and opportunity to cure, as required by state law. In its answer to the suit, the State denied that anyone with proper authority approved the late payments. As to the second basis for termination, the suit contends that Jefferson Island's lease with the State of Louisiana was amended in 2004 so that mining operations are no longer required to maintain the lease. The State's answer denies that the 2004 amendment was properly authorized. If we are unable to reach a settlement, we are not able to predict the outcome of the litigation. As of January 2008, our current estimate of costs incurred that would be considered unusable if the Louisiana DNR was successful in terminating our lease and causing us to cease the expansion project is approximately $6 million.

Note 8 - 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 and Other Tax Credits

Deferred investment tax credits associated with distribution operations are included as a regulatory liability in our consolidated balance sheets (see Note 1, "Accounting Policies and Methods of Application"). These investment tax credits are being amortized over the estimated life of the related properties as credits to income in accordance with regulatory requirements. In 2007, we invested in a guaranteed affordable housing tax credit fund. 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, including the affordable housing credits. Components of income tax expense shown in the statements of consolidated income are shown in the following table.

Income Tax Expense The relative split between current and deferred taxes is due to a variety of factors including true ups of prior year tax returns, and most importantly, the timing of our property-related deductions.

In millions	2007	2006	2005
Current income taxes			
Federal	$86	$(4)	$84
State	12	2	18
Deferred income taxes			
Federal	23	115	17
State	7	18	-
Amortization of investment tax credits	(1)	(2)	(2)
Total	$127	$129	$117

The reconciliations between the statutory federal income tax rate, the effective rate and the related amount of tax for the years ended December 31, 2007, 2006 and 2005 are presented in the following tables.

In millions	2007 Amount	2007 % of pretax income	2006 Amount	2006 % of pretax income	2005 Amount	2005 % of pretax income
Computed tax expense at statutory rate	$118	35.0%	$119	35.0%	$109	35.0%
State income tax, net of federal income tax benefit	13	3.8	12	3.6	11	3.7
Amortization of investment tax credits	(1)	(0.3)	(2)	(0.5)	(2)	(0.6)
Affordable housing credits	(1)	(0.3)	-	-	-	-
Flexible dividend deduction	(2)	(0.6)	(2)	(0.5)	(2)	(0.6)
Other – net	-	-	2	0.2	1	0.2
Total income tax expense at effective rate	$127	37.6%	$129	37.8%	$117	37.7%

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. We report the tax effects of the differences in those items as deferred income tax assets or liabilities in our consolidated balance sheets. We measure the assets and liabilities using income tax rates that are currently in effect. Because of the regulated nature of the utilities' business, we recorded a regulatory tax liability in accordance with SFAS 109, which we are amortizing over approximately 30 years (see Note 1 "Accounting Policies and Methods of Application"). Our deferred tax assets include $35 million related to an unfunded pension and postretirement benefit obligation and did not change from 2006.

As indicated in the following table, 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 reduce 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 December 31, 2007	As of December 31, 2006
Accumulated deferred income tax liabilities		
Property – accelerated depreciation and other property-related items	$568	$520
Mark to market	4	7
Other	44	22
Total accumulated deferred income tax liabilities	616	549
Accumulated deferred income tax assets		
Deferred investment tax credits	6	7
Unfunded pension and postretirement benefit obligation	35	35
Net operating loss – NUI (1)	5	5
Other	7	-
Total accumulated deferred income tax assets	53	47
Valuation allowances (2)	(3)	(3)
Total accumulated deferred income tax assets, net of valuation allowance	50	44
Net accumulated deferred tax liability	$566	$505

(1) Expire in 2021.
(2) Valuation allowance is due to the net operating losses on NUI headquarters that are not usable in New Jersey.

In June 2006, the FASB issued FIN 48, which addressed the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under FIN 48, we may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties on income taxes, accounting in interim periods and requires increased disclosures. We adopted the provisions of FIN 48 on January 1, 2007. At the date of adoption, and as of December 31, 2007, we did not have a liability for unrecognized tax benefits. Based on current information, we do not anticipate that this will change materially in 2008.

We recognize accrued interest and penalties related to uncertain tax positions in operating expenses in the consolidated statements of income, which is consistent with the recognition of these items in prior reporting periods. As of December 31, 2007, we did not have a liability recorded for payment of interest and penalties associated with uncertain tax positions.

We file a U.S. federal consolidated income tax return and various state income tax returns. We are no longer subject to income tax examinations by the Internal Revenue Service or any state for years before 2002.

Note 9 - Segment Information

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. We generate nearly all our operating revenues through the sale, distribution, transportation and storage of natural gas. We are involved in several related and complementary businesses, including retail natural gas marketing to end-use customers primarily in Georgia; natural gas asset management and related logistics activities for each of our utilities as well as for nonaffiliated companies; natural gas storage arbitrage and related activities; and the development and operation of high-deliverability natural gas storage assets. We manage these businesses through four operating segments – distribution operations, retail energy operations, wholesale services and energy investments and a nonoperating corporate segment which includes intercompany eliminations.

We evaluate segment performance based primarily on the non-GAAP measure of EBIT, which includes the effects of corporate expense allocations. EBIT is a non-GAAP measure that includes operating income, other income and expenses and minority interest. Items we do not include in EBIT are financing costs, including interest and debt expense and income taxes, each of which we evaluate on a consolidated level. We believe EBIT is a useful measurement of our performance because it provides information that can be used to evaluate the effectiveness of our businesses from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which 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 2007, 2006 and 2005 are presented below.

In millions	2007	2006	2005
Operating revenues	$2,494	$2,621	$2,718
Operating expenses	2,005	2,133	2,276
Operating income	489	488	442
Minority interest	(30)	(23)	(22)
Other income (expense)	4	(1)	(1)
EBIT	463	464	419
Interest expense	125	123	109
Earnings before income taxes	338	341	310
Income taxes	127	129	117
Net income	$211	$212	$193

Summarized income statement, balance sheet and capital expenditure information by segment as of and for the years ended December 31, 2007, 2006 and 2005 is shown in the following tables.

2007

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intercompany eliminations	Consolidated AGL Resources
Operating revenues from external parties	$1,477	$892	$83	$42	$-	$2,494
Intercompany revenues (1)	188	-	-	-	(188)	-
Total operating revenues	1,665	892	83	42	(188)	2,494
Operating expenses						
Cost of gas	845	704	6	2	(188)	1,369
Operation and maintenance	330	69	38	19	(5)	451
Depreciation and amortization	122	5	4	5	8	144
Taxes other than income taxes	33	1	1	1	5	41
Total operating expenses	1,330	779	49	27	(180)	2,005
Operating income (loss)	335	113	34	15	(8)	489
Minority interest	-	(30)	-	-	-	(30)
Other income	3	-	-	-	1	4
EBIT	$338	$83	$34	$15	$(7)	$463
Identifiable and total assets	$4,831	$284	$900	$287	$(34)	$6,268
Goodwill	$406	$-	$-	$14	$-	$420
Capital expenditures	$201	$2	$2	$26	$28	$259

2006

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intercompany eliminations	Consolidated AGL Resources
Operating revenues from external parties	$1,467	$930	$182	$41	$1	$2,621
Intercompany revenues (1)	157	-	-	-	(157)	-
Total operating revenues	1,624	930	182	41	(156)	2,621
Operating expenses						
Cost of gas	817	774	43	5	(157)	1,482
Operation and maintenance	350	64	46	20	(7)	473
Depreciation and amortization	116	3	2	5	12	138
Taxes other than income taxes	33	1	1	1	4	40
Total operating expenses	1,316	842	92	31	(148)	2,133
Operating income (loss)	308	88	90	10	(8)	488
Minority interest	-	(23)	-	-	-	(23)
Other income (expense)	2	(2)	-	-	(1)	(1)
EBIT	$310	$63	$90	$10	$(9)	$464
Identifiable and total assets	$4,565	$298	$849	$373	$62	$6,147
Goodwill	$406	$-	$-	$14	$-	$420
Capital expenditures	$174	$9	$2	$23	$45	$253

2005

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intercompany eliminations	Consolidated AGL Resources
Operating revenues from external parties	$1,571	$996	$95	$56	$-	$2,718
Intercompany revenues (1)	182	-	-	-	(182)	-
Total operating revenues	1,753	996	95	56	(182)	2,718
Operating expenses						
Cost of gas	939	850	3	16	(182)	1,626
Operation and maintenance	372	58	39	17	(9)	477
Depreciation and amortization	114	2	2	5	10	133
Taxes other than income taxes	32	1	1	1	5	40
Total operating expenses	1,457	911	45	39	(176)	2,276
Operating income (loss)	296	85	50	17	(6)	442
Minority interest	-	(22)	-	-	-	(22)
Other income (expense)	3	-	(1)	2	(5)	(1)
EBIT	$299	$63	$49	$19	$(11)	$419
Identifiable and total assets	$4,788	$343	$1,058	$350	$(219)	$6,320
Goodwill	$406	$-	$-	$14	$-	$420
Capital expenditures	$215	$4	$1	$9	$38	$267

(1) Intercompany revenues – Wholesale services records its energy marketing and risk management revenue on a net basis. Wholesale services total operating revenues include intercompany revenues of $638 million in 2007, $531 million in 2006 and $792 million in 2005.

Note 10 - Quarterly Financial Data (Unaudited)

Our quarterly financial data for 2007, 2006 and 2005 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	March 31	June 30	Sept. 30	Dec. 31
2007				
Operating revenues	$973	$467	$369	$685
Operating income	216	78	55	140
Net income	102	30	13	66
Basic earnings per share	1.31	0.40	0.17	0.86
Diluted earnings per share	1.30	0.40	0.17	0.86
2006				
Operating revenues	$1,044	$436	$434	$707
Operating income	228	60	90	110
Net income	110	19	36	47
Basic earnings per share	1.42	0.25	0.46	0.60
Diluted earnings per share	1.41	0.25	0.46	0.60
2005				
Operating revenues	$908	$430	$387	$993
Operating income	181	66	54	141
Net income	88	24	15	66
Basic earnings per share	1.15	0.31	0.19	0.86
Diluted earnings per share	1.14	0.30	0.19	0.85

Our basic and 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 diluted earnings per share shown in 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.

Report of Independent Registered Public Accounting Firm

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

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of AGL Resources Inc. and its subsidiaries at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Notes 4 and 3, respectively, to the consolidated financial statements, AGL Resources Inc. and subsidiaries changed its method of accounting for stock based compensation plans as of January 1, 2006 and its method of accounting for defined benefit pension and other postretirement plans as of December 31, 2006. In addition, as discussed in Note 8, effective January 1, 2007, the Company changed its method of accounting for uncertain tax positions.

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.

/s/ PricewaterhouseCoopers LLP
Atlanta, Georgia
February 5, 2008

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

None

ITEM 9A. CONTROLS AND PROCEDURES

Conclusions Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act). Based on this evaluation, our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2007, in providing a reasonable level of assurance that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods in SEC rules and forms, including a reasonable level of assurance that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our principal executive officer and our principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

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).

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, 2007, in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

February 5, 2008

/s/ John W Somerhalder II
John W. Somerhalder II
Chairman, President and Chief Executive Officer

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

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting identified in connection with the above-referenced evaluation by management of the effectiveness of our internal control over financial reporting that occurred during the fourth quarter ended December 31, 2007, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION.

None

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item with respect to directors will be set forth under the captions "Proposal I -Election of Directors", - "Corporate Governance - Ethics and Compliance Program," – "Committees of the Board" and "- Audit Committee" in the Proxy Statement for our 2008 Annual Meeting of Shareholders or in a subsequent amendment to this report. The information required by this item with respect to the executive officers is set forth at Part I, Item 4 of this report under the caption "Executive Officers of the Registrant." The information required by this item with respect to Section 16(a) beneficial ownership reporting compliance will be set forth under the caption "Section 16(a) Beneficial Ownership Reporting Compliance" in the Proxy Statement or subsequent amendment referred to above. All such information that is provided in the Proxy Statement is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item will be set forth under the captions "Compensation and Management Development Committee Report," "Compensation and Management Development Committee Interlocks and Insider Participation," "Director Compensation," "Compensation Discussion and Analysis" and "Executive Compensation" in the Proxy Statement or subsequent amendment referred to in Item 10 above.

All such information that is provided in the Proxy Statement is incorporated herein by reference, except for the information under the caption "Compensation and Management Development Committee Report" which is specifically not so incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this item will be set forth under the captions "Share Ownership" and "Executive Compensation -- Equity Compensation Plan Information" in the Proxy Statement or subsequent amendment referred to in Item 10 above. All such information that is provided in the Proxy Statement is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information required by this item will be set forth under the captions "Corporate Governance – Director Independence" and "- Policy on Related Person Transactions" and "Certain Relationships and Related Transactions" in the Proxy Statement or subsequent amendment referred to in Item 10 above. All such information that is provided in the Proxy Statement is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this item will be set forth under the caption "Proposal 2 – Ratification of the Appointment of PricewaterhouseCoopers LLP as Our Independent Registered Public Accounting Firm for 2008" in the Proxy Statement or subsequent amendment to referred to in Item 10 above. All such information that is provided in the Proxy Statement is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents Filed as Part of This Report.

(1) Financial Statements Included in Item 8 are the following financial statements:

- Consolidated Balance Sheets as of December 31, 2007 and 2006
- Statements of Consolidated Income for the years ended December 31, 2007, 2006, and 2005
- Statements of Consolidated Common Shareholders' Equity for the years ended December 31, 2007, 2006 and 2005
- Statements of Consolidated Cash Flows for the years ended December 31, 2007, 2006, and 2005
- Notes to Consolidated Financial Statements
- Report of Independent Registered Public Accounting Firm

(2) Financial Statement Schedules

Financial Statement Schedule II. Valuation and Qualifying Accounts - Allowance for Uncollectible Accounts and Income Tax Valuations for Each of the Three Years in the Period Ended December 31, 2007.

Schedules other than those referred to above are omitted and are not applicable or not required, or the required information is shown in the financial statements or notes thereto.

(3) Exhibits

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

3.1	Amended and Restated Articles of Incorporation filed November 2, 2005, with the Secretary of State of the state of Georgia (Exhibit 3.1, AGL Resources Inc. Form 8-K dated November 2, 2005).
3.2a	Bylaws, as amended on October 26, 2006 (Exhibit 3.2, AGL Resources, Inc. Form 8-K dated November 1, 2006).
3.2b	Bylaws, as amended on October 31, 2007 (Exhibit 3.2, AGL Resources, Inc. Form 8-K dated October 31, 2007).
4.1.a	Specimen form of Common Stock certificate (Exhibit 4.1, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 1999).
4.1.b	Specimen AGL Capital Corporation 6.00% Senior Notes due 2034 (Exhibit 4.1, AGL Resources Inc. Form 8-K dated September 27, 2004).
4.1.c	Specimen AGL Capital Corporation 4.95% Senior Notes due 2015. (Exhibit 4.1, AGL Resources Inc. Form 8-K dated December 21, 2004).
4.1.d	Specimen form of Right certificate (Exhibit 1, AGL Resources Inc. Form 8-K filed March 6, 1996).

4.1.e Specimen AGL Capital Corporation 6.375% Senior Secured Notes due 2016. (Exhibit 4.1, AGL Resources Inc. Form 8-K dated December 11, 2007).

4.1.f Specimen AGL Capital Corporation 7.125% Senior Secured Notes due 2011.

4.1.g Specimen AGL Capital Corporation 4.45% Senior Secured Notes due 2013.

4.2.a Indenture, dated as of December 1, 1989, between Atlanta Gas Light Company and Bankers Trust Company, as Trustee (Exhibit 4(a), Atlanta Gas Light Company registration statement on Form S-3, No. 33-32274).

4.2.b First Supplemental Indenture dated as of March 16, 1992, between Atlanta Gas Light Company and NationsBank of Georgia, National Association, as Successor Trustee (Exhibit 4(a), Atlanta Gas Light Company registration statement on Form S-3, No. 33-46419).

4.2.c Indenture, dated February 20, 2001 among AGL Capital Corporation, AGL Resources Inc. and The Bank of New York, as Trustee (Exhibit 4.2, AGL Resources Inc. registration statement on Form S-3, filed on September 17, 2001, No. 333-69500).

4.3.a Form of Guarantee of AGL Resources Inc. dated as of December 14, 2007 regarding the AGL Capital Corporation 6.375% Senior Note due 2016 (Exhibit 4.2, AGL Resources Inc. Form 8-K dated December 11, 2007).

4.3.b Form of Guarantee of AGL Resources Inc. dated as of September 27, 2004 regarding the AGL Capital Corporation 6.00% Senior Note due 2034 (Exhibit 4.1, AGL Resources Inc. Form 8-K dated September 27, 2004).

4.3.c Form of Guarantee of AGL Resources Inc. dated as of December 20, 2004 regarding the AGL Capital Corporation 4.95% Senior Note due 2015 (Exhibit 4.1, AGL Resources Inc. Form 8-K dated December 21, 2004).

4.3.d Form of Guarantee of AGL Resources Inc. dated as of March 31, 2001 regarding the AGL Capital Corporation 7.125% Senior Note due 2011.

4.3.e Form of Guarantee of AGL Resources Inc. dated as of July 2, 2003 regarding the AGL Capital Corporation 4.45% Senior Note due 2011.

4.4.a Rights Agreement dated as of March 6, 1996 between AGL Resources Inc. and Wachovia Bank of North Carolina, N.A. as Rights Agent (Exhibit 1, AGL Resources Inc. Form 8-A dated March 6, 1996).

4.4.b Second Amendment to Rights Agreement dated as of June 5, 2002 between AGL Resources Inc. and Equiserve Trust Company, N.A. (Exhibit 1, AGL Resources Inc. Amendment No. 1 to Form 8-A dated June 2, 2002).

10.1 Director and Executive Compensation Contracts, Plans and Arrangements.

Director Compensation Contracts, Plans and Arrangements

10.1.a AGL Resources Inc. Amended and Restated 1996 Non-Employee Directors Equity Compensation Plan (Exhibit 10.1, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2002).

10.1.b First Amendment to the AGL Resources Inc. Amended and Restated 1996 Non-Employee Directors Equity Compensation Plan (Exhibit 10.1.o, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2002).

10.1.c Second Amendment to the AGL Resources Inc. Amended and Restated 1996 Non-Employee Directors Equity Compensation Plan (Exhibit 10.1.k, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

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

10.1.e First Amendment to the AGL Resources Inc. 2006 Non-Employee Directors Equity Compensation Plan (Exhibit 10.1.i, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.f AGL Resources Inc. 1998 Common Stock Equivalent Plan for Non-Employee Directors (Exhibit 10.1.b, AGL Resources Inc. Form 10-Q for the quarter ended December 31, 1997).

10.1.g First Amendment to the AGL Resources Inc. 1998 Common Stock Equivalent Plan for Non-Employee Directors (Exhibit 10.5, AGL Resources Inc. Form 10-Q for the quarter ended March 31, 2000).

10.1.h Second Amendment to the AGL Resources Inc. 1998 Common Stock Equivalent Plan for Non-Employee Directors (Exhibit 10.4, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2002).

10.1.i Third Amendment to the AGL Resources Inc. 1998 Common Stock Equivalent Plan for Non-Employee Directors (Exhibit 10.5, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2002).

10.1.j Fourth Amendment to the AGL Resources Inc. 1998 Common Stock Equivalent Plan for Non-Employee Directors (Exhibit 10.1.m, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.k Description of Directors' Compensation (Exhibit 10.1, AGL Resources Inc. Form 8-K dated December 1, 2004).

10.1.l Description of Director's Compensation with respect to the annual retainer and description of Director non-employee share-ownership guidelines (Item 1.01, AGL Resources Inc. Form 8-K dated December 7, 2005).

10.1.m Description of Director's Compensation with respect to the annual retainer and description of Director non-employee share-ownership guidelines (Item 1.01, AGL Resources Inc. Form 8-K dated October 26, 2006).

10.1.n Form of Stock Award Agreement for Non-Employee Directors (Exhibit 10.1.aj, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2004).

10.1.o Form on Nonqualified Stock Option Agreement for Non-Employee Directors (Exhibit 10.1.ak, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2004).

10.1.p Form of Director Indemnification Agreement, dated April 28, 2004, between AGL Resources Inc., on behalf of itself and the Indemnities named therein (Exhibit 10.3, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2004).

Executive Compensation Contracts, Plans and Arrangements

10.1.q AGL Resources Inc. Long-Term Stock Incentive Plan of 1990 (Exhibit 10(ii), Atlanta Gas Light Company Form 10-K for the fiscal year ended September 30, 1991).

10.1.r First Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan of 1990 (Exhibit B to the Atlanta Gas Light Company Proxy Statement for the Annual Meeting of Shareholders held February 5, 1993).

10.1.s Second Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan of 1990 (Exhibit 10.1.d, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 1997).

10.1.t Third Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan of 1990 (Exhibit C to the Proxy Statement and Prospectus filed as a part of Amendment No. 1 to Registration Statement on Form S-4, No. 33-99826).

10.1.u Fourth Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan of 1990 (Exhibit 10.1.f, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 1997).

10.1.v Fifth Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan of 1990 (Exhibit 10.1.g, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 1997).

10.1.w Sixth Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan of 1990 (Exhibit 10.1.a, AGL Resources Inc. Form 10-Q for the quarter ended March 31, 1998).

10.1.x Seventh Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan of 1990 (Exhibit 10.1, AGL Resources Inc. Form 10-Q for the quarter ended December 31, 1998).

10.1.y Eighth Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan of 1990 (Exhibit 10.1, AGL Resources Inc. Form 10-Q for the quarter ended March 31, 2000).

10.1.z Ninth Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan 1990 (Exhibit 10.6, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2002).

10.1.aa Tenth Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan 1990 (Exhibit 10.1.n, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.ab AGL Resources Inc. Long-Term Incentive Plan (1999), as amended and restated as of January 1, 2002 (Exhibit 99.2, AGL Resources Inc. Form 10-Q for the quarter ended March 31, 2002).

10.1.ac First amendment to the AGL Resources Inc. Long-Term Incentive Plan (1999), as amended and restated (Exhibit 10.1.b, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2004).

10.1.ad Second amendment to the AGL Resources Inc. Long-Term Incentive Plan (1999), as amended and restated (Exhibit 10.1.l, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.ae AGL Resources Inc. Officer Incentive Plan (Exhibit 10.2, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2001).

10.1.af First amendment to the AGL Resources Inc. Officer Incentive Plan (Exhibit 10.1.j, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.ag AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Annex A of AGL Resources Inc.'s Schedule 14A, File No. 001-14174, filed with the Securities and Exchange Commission on March 19, 2007).

10.1.ah Form of Incentive Stock Option Agreement - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.b, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.ai Form of Nonqualified Stock Option Agreement - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.c, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.aj Form of Performance Cash Award Agreement - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.d, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.ak Form of Restricted Stock Agreement (performance based) - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.e, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.al Form of Restricted Stock Agreement (time based) - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.f, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.am Form of Restricted Stock Unit Agreement - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan. (Exhibit 10.1.g, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007)

10.1.an Form of Stock Appreciation Rights Agreement - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.h, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.ao Form of Incentive Stock Option Agreement, Nonqualified Stock Option Agreement and Restricted Stock Agreement for key employees (Exhibit 10.1, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2004).

10.1.ap Form of Performance Unit Agreement for key employees (Exhibit 10.1.e, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2004).

10.1.aq Forms of Nonqualified Stock Option Agreement without the reload provision (LTIP and Officer Plan) (Exhibit 10.1, AGL Resources Inc. Form 8-K dated March 15, 2005).

10.1.ar Form of Nonqualified Stock Option Agreement with the reload provision (Officer Plan) (Exhibit 10.2, AGL Resources Inc. Form 8-K dated March 15, 2005).

10.1.as Form of Restricted Stock Unit Agreement and Performance Cash Unit Agreement for key employees (Exhibit 10.1 and 10.2, respectively, AGL Resources Inc. Form 8-K dated February 24, 2006).

10.1.at AGL Resources Inc. Nonqualified Savings Plan as amended and restated as of January 1, 2007 (Exhibit 10.1.af, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2006).

10.1.au AGL Resources Inc. Executive Performance Incentive Plan dated February 2, 2002 (Exhibit 99.1, AGL Resources Inc. Form 10-Q for the quarter ended March 31, 2002).

10.1.av AGL Resources Inc. Annual Incentive Plan - 2006 (Exhibit 10.1, AGL Resources Inc. Form

8-K/A dated February 24, 2006).

10.1.aw AGL Resources Inc. Annual Incentive Plan - 2007 (Exhibit 10.1, AGL Resources Inc. Form 8-K dated August 6, 2007).

10.1.ax Description of Annual Incentive Compensation Arrangement for Douglas N. Schantz.

10.1.ay Continuity Agreement, dated December 1, 2003, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Kevin P. Madden (Exhibit 10.1.w, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2003).

10.1.az Amendment to Continuity Agreement, dated February 24, 2006, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Kevin P. Madden (Exhibit 10.6, AGL Resources Inc. Form 8-K/A dated February 24, 2006).

10.1.ba Continuity Agreement, dated December 1, 2003, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Paul R. Shlanta (Exhibit 10.1.z, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2003).

10.1.bb Amendment to Continuity Agreement, dated February 24, 2006, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Paul R. Shlanta (Exhibit 10.7, AGL Resources Inc. Form 8-K/A dated February 24, 2006).

10.1.bc Continuity Agreement, dated September 30, 2005, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Andrew W. Evans (Exhibit 10.1, AGL Resources Inc. Form 8-K dated September 27, 2005).

10.1.bd Amendment to Continuity Agreement, dated February 24, 2006, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Andrew W, Evans (Exhibit 10.5, AGL Resources Inc. Form 8-K/A dated February 24, 2006).

10.1.be Continuity Agreement, dated January 1, 2006, by and between AGL Resources, Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and R. Eric Martinez, Jr. (Exhibit 10.4, AGL Resources Inc. Form 8-K/A dated February 24, 2006).

10.1.bf Continuity Agreement, dated March 3, 2006, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and John W. Somerhalder II (Exhibit 10.2 AGL Resources, Inc. Form 8-K dated March 8, 2006).

10.1.bg Continuity Agreement, dated March 15, 2006, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Douglas N. Schantz (Exhibit 10.1.as AGL Resources, Inc. Form 10-K for the fiscal year ended December 31, 2006).

10.1.bh Continuity Agreement, dated December 1, 2007, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and John W. Somerhalder II (Exhibit 10.1.a AGL Resources, Inc. Form 8-K dated January 8, 2008).

10.1.bi Continuity Agreement, dated December 1, 2007, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Andrew W. Evans (Exhibit 10.1.b AGL Resources, Inc. Form 8-K dated January 8, 2008).

10.1.bj Continuity Agreement, dated December 1, 2007, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Kevin P. Madden (Exhibit 10.1.c AGL Resources, Inc. Form 8-K dated January 8, 2008).

10.1.bk Continuity Agreement, dated December 1, 2007, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Douglas N. Schantz (Exhibit 10.1.d AGL Resources, Inc. Form 8-K dated January 8, 2008).

10.1.bl Continuity Agreement, dated December 1, 2007, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Paul R. Shlanta.

10.1.bm Form of AGL Resources Inc. Executive Post Employment Medical Benefit Plan (Exhibit 10.1.d, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2003).

10.1.bn Description of Compensation Agreement for each of Kevin P. Madden, R. Eric Martinez, Jr., Paul R. Shlanta and Andrew W. Evans (Item 1.01, AGL Resources Inc. Form 8-K, dated February 1, 2006).

10.1.bo Description of Compensation Agreement for each of Andrew W. Evans and R. Eric Martinez, Jr. (Item 1.01, AGL Resources Inc. Form 8-K, dated May 2, 2006).

10.1.bp Description of compensation for each of John W. Somerhalder, Andrew W. Evans, Kevin P. Madden, R. Eric Martinez Jr. and Paul R. Shlanta (Item 1.01, AGL Resources Inc. Form 8-K, dated January 30, 2007).

10.1.bq Description of One-Time Cash Award for D. Raymond Riddle and Chairman of the Board Retainer (Item 5.02, AGL Resources Inc. Form 8-K, dated March 23, 2007).

10.1.br AGL Resources Inc. Share Repurchase Program, dated February 3, 2006 (Item 1.01 AGL Resources Inc. Form 8-K, dated February 1, 2006).

10.2 Guaranty Agreement, effective December 13, 2005, by and between Atlanta Gas Light Company and AGL Resources Inc. (Exhibit 10.2, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2006)

10.3 Form of Commercial Paper Dealer Agreement between AGL Capital Corporation, as Issuer, AGL Resources Inc., as Guarantor, and the Dealers named therein, dated September 25, 2000 (Exhibit 10.79, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 2000).

10.4 Guarantee of AGL Resources Inc., dated October 5, 2000, of payments on promissory notes issued by AGL Capital Corporation (AGLCC) pursuant to the Issuing and Paying Agency Agreement dated September 25, 2000, between AGLCC and The Bank of New York (Exhibit 10.80, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 2000).

10.5 Issuing and Paying Agency Agreement, dated September 25, 2000, between AGL Capital Corporation and The Bank of New York. (Exhibit 10.81, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 2000).

10.6 Amended and Restated Master Environmental Management Services Agreement, dated July 25, 2002 by and between Atlanta Gas Light Company and The RETEC Group, Inc. (Exhibit 10.2, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2003). (Confidential treatment pursuant to 17 CFR Sections 200.80 (b) and 240.24-b has been granted regarding certain portions of this exhibit, which portions have been filed separately with the Commission).

10.7 Credit Agreement dated as of August 31, 2006, by and among AGL Resources Inc., AGL Capital Corporation, SunTrust Bank, as administrative agent, Wachovia Bank, National Association, as syndication agent, JPMorgan Chase Bank, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd. and Calyon New York Branch, as co-documentation agents, and the several other banks and other financial institutions named therein (Exhibit 10, AGL Resources Inc. Form 8-K dated August 31, 2006).

10.8 SouthStar Energy Services LLC Agreement, dated April 1, 2004 by and between Georgia Natural Gas Company and Piedmont Energy Company (Exhibit 10, AGL Resources Inc. Form 10-Q for the quarter ended March 31, 2004).

14 AGL Resources Inc. Code of Ethics for its Chief Executive Officer and its Senior Financial Officers (Exhibit 14, AGL Resources Inc. Form 10-K for the year ended December 31, 2004).

21 Subsidiaries of AGL Resources Inc.

23 Consent of PricewaterhouseCoopers LLP, independent registered public accounting firm.

24 Powers of Attorney (included on signature page hereto).

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

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

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

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

(b) Exhibits filed as part of this report.

See Item 15(a)(3).

(c) Financial statement schedules filed as part of this report.

See Item 15(a)(2).

SIGNATURES

In accordance with Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned; thereunto duly authorized, on February 6, 2008.

AGL RESOURCES INC.

By: /s/ John W. Somerhalder II
John W. Somerhalder II
Chairman, President and Chief Executive Officer

Power of Attorney

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints John W. Somerhalder II, Andrew W. Evans, Paul R. Shlanta and Bryan E. Seas, and each of them, his or her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K for the year ended December 31, 2007, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite or necessary to be done, as fully to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated as of February 6, 2008.

Signatures	**Title**
/s/ John W. Somerhalder II John W. Somerhalder II	Chairman, President and Chief Executive Officer (Principal Executive Officer)
/s/ Andrew W. Evans Andrew W. Evans	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ Bryan E. Seas Bryan E. Seas	Vice President, Controller and Chief Accounting Officer (Principal Accounting Officer)
/s/ Thomas D. Bell, Jr. Thomas D. Bell, Jr.	Director
/s/ Charles R. Crisp Charles R. Crisp	Director
/s/ Michael J. Durham Michael J. Durham	Director
/s/ Arthur E. Johnson Arthur E. Johnson	Director
/s/ Wyck A. Knox, Jr. Wyck A. Knox, Jr.	Director
/s/ Dennis M. Love Dennis M. Love	Director
/s/ Charles H. McTier Charles H. McTier	Director
/s/ Dean R. O'Hare Dean R. O'Hare	Director
/s/ D. Raymond Riddle D. Raymond Riddle	Director
/s/ James A. Rubright James A. Rubright	Director
/s/ Felker W. Ward, Jr. Felker W. Ward, Jr.	Director
/s/ Bettina M. Whyte Bettina M. Whyte	Director
/s/ Henry C. Wolf Henry C. Wolf	Director

Schedule II

AGL Resources Inc. and Subsidiaries

VALUATION AND QUALIFYING ACCOUNTS - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS AND INCOME TAX VALUATION FOR EACH OF THE THREE YEARS IN THE PERIOD ENDED DECEMBER 31, 2007.

In millions	Allowance for uncollectible accounts	Income tax valuation
Balance at December 31, 2004	$15	$8
Provisions charged to income in 2005	17	-
Accounts written off as uncollectible, net in 2005	(17)	-
Additional valuation allowances	-	1
Balance at December 31, 2005	15	9
Provisions charged to income in 2006	22	-
Accounts written off as uncollectible, net in 2006	(22)	-
Decrease due to change in circumstances	-	(6)
Balance at December 31, 2006	15	3
Provisions charged to income in 2007	19	-
Accounts written off as uncollectible, net in 2007	(20)	-
Balance at December 31, 2007	$14	$3