AGL RESOURCES INC
Form 10-K
February 09, 2011

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2010

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

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

| Title of each 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 þ 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 þ

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 þ No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ 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, a non-accelerated filer, or a smaller reporting company

Large accelerated filer þ Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨

(Do not check if smaller reporting company)

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

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, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter, was $2,792,228,461.

The number of shares of the registrant's common stock outstanding as of January 31, 2011 was 77,999,557.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the Proxy Statement for the 2011 Annual Meeting of Shareholders ("Proxy Statement") to be held May 3, 2011, are incorporated by reference in Part III.

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GLOSSARY OF KEY TERMS

| | |
|---|---|
| AGL Capital | AGL Capital Corporation |
| AGL Networks | AGL Networks, LLC |
| Atlanta Gas Light | Atlanta Gas Light Company |
| Bcf | Billion cubic feet |
| Bridge Facility | $1.05 billion credit agreement entered into by AGL Capital to help finance a portion of the proposed merger with Nicor. |
| Chattanooga Gas | Chattanooga Gas Company |
| Credit Facility | $1 billion credit agreement entered into by AGL Capital |
| EBIT | Earnings before interest and taxes, a non-GAAP measure that includes operating income and other income and excludes financing costs, including interest and debt and income tax expense each of which we evaluate on a consolidated level; as an indicator of our operating performance, EBIT should not be considered an alternative to, or more meaningful than, earnings before income taxes, or net income attributable to AGL Resources Inc. as determined in accordance with GAAP |
| ERC | Environmental remediation costs associated with our distribution operations segment which are generally recoverable through rate mechanisms |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| Fitch | Fitch Ratings |
| Florida Commission | Florida Public Service Commission, the state regulatory agency for Florida City Gas |
| GAAP | Accounting principles generally accepted in the United States of America |
| Georgia Commission | Georgia Public Service Commission, the state regulatory agency for Atlanta Gas Light |
| GNG | Georgia Natural Gas, the name under which SouthStar does business in Georgia |
| Golden Triangle Storage | Golden Triangle Storage, Inc. |
| Hampton Roads | Virginia Natural Gas' pipeline project which connects its northern and southern pipelines |
| Heating Degree Days | A measure of the effects of weather on our businesses, calculated when the average daily temperatures are less than 65 degrees Fahrenheit |
| 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 |
| Henry Hub | A major interconnection point of natural gas pipelines in Erath, Louisiana where NYMEX natural gas future contracts are priced |
| Jefferson Island | Jefferson Island Storage & Hub, LLC |
| LNG | Liquefied natural gas |
| LOCOM | Lower of weighted average cost or current market price |
| Magnolia | Magnolia Enterprise Holdings, Inc. |
| Marketers | Marketers selling retail natural gas in Georgia and certificated by the Georgia Commission |
| Mcf | Million cubic feet |
| MGP | Manufactured gas plant |
| Moody's | Moody's Investors Service |
| New Jersey BPU | New Jersey Board of Public Utilities, the state regulatory agency for Elizabethtown Gas |
| Nicor | Nicor Inc., an Illinois corporation |

| | |
|---|---|
| NUI | NUI Corporation – an acquisition completed in November 2004 |
| NYMEX | New York Mercantile Exchange, Inc. |
| OCI | Other comprehensive income |
| Operating margin | A non-GAAP measure of income, calculated as operating 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 Consolidated Statements of Income. Operating margin should not be considered an alternative to, or more meaningful than, operating income as determined in accordance with GAAP |
| OTC | Over-the-counter |
| Piedmont | Piedmont Natural Gas Company, Inc. |
| Pivotal Utility | Pivotal Utility Holdings, Inc., doing business as Elizabethtown Gas, Elkton Gas and Florida City Gas |
| PP&E | Property, plant and equipment |
| S&P | Standard & Poor's Ratings Services |
| SEC | Securities and Exchange Commission |
| Sequent | Sequent Energy Management, L.P. |
| SouthStar | SouthStar Energy Services LLC |
| STRIDE | Atlanta Gas Light's Strategic Infrastructure Development and Enhancement program |
| Tennessee Authority | Tennessee Regulatory Authority, the state regulatory agency for Chattanooga Gas. |
| Term Loan Facility | $300 million credit agreement entered into by AGL Capital to repay the $300 million senior notes due in 2011 |
| 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, the state regulatory agency for Virginia Natural Gas |
| WACOG | Weighted average cost of gas |
| WNA | Weather normalization adjustment |

Forward-Looking Statements

Certain expectations and projections regarding our future performance referenced in this section and elsewhere in this report, as well as in other reports and proxy statements we file with the SEC or otherwise release to the public and on our website are forward-looking statements within the meaning of the U.S. federal securities laws and are subject to uncertainties and risks, as itemized in Item 1A “Risk Factors”, in this Form 10-K. Senior officers and other employees may also make verbal statements to analysts, investors, regulators, the media and others that are forward-looking.

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

Such events, risks and uncertainties include, but are not limited to, changes in price, supply and demand for natural gas and related products; the impact of changes in state and federal legislation and regulation including any changes related to climate change; actions taken by government agencies on rates and other matters; concentration of credit risk; utility and energy industry consolidation; the impact on cost and timeliness of construction projects by government and other approvals, development project delays, adequacy of supply of diversified vendors, unexpected change in project costs, including the cost of funds to finance these projects; the impact of acquisitions and divestitures; direct or indirect effects on our business, financial condition or liquidity resulting from a change in our credit ratings or the credit ratings of our counterparties or competitors; interest rate fluctuations; financial market conditions, including recent disruptions in the capital markets and lending environment and the current economic downturn; and general economic conditions; uncertainties about environmental issues and the related impact of such issues; the impact of changes in weather, including climate change, on the temperature-sensitive portions of our business; the impact of natural disasters such as hurricanes on the supply and price of natural gas; acts of war or terrorism; and other factors described in detail in our filings with the SEC.

In addition, actual results may differ materially due to the expected timing and likelihood of completion of the proposed merger with Nicor, including the timing, receipt and terms and conditions of any required governmental and regulatory approvals of the proposed merger that could reduce anticipated benefits or cause the parties to abandon the merger, the diversion of management's time and attention from our ongoing business during this time period, the ability to maintain relationships with customers, employees or suppliers as well as the ability to successfully integrate the businesses and realize cost savings and any other synergies and the risk that the credit ratings of the combined company or its subsidiaries may be different from what the companies expect.

We caution readers that the important factors described elsewhere in this report, among others, could cause our business, results of operations or financial condition to differ significantly from those expressed in any forward-looking statements. There also may be other factors that we cannot anticipate or that are not described in this report that could cause results to differ significantly from our expectations.

Forward-looking statements are only as of the date they are made. We undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of future events, new information or otherwise, except as required under U.S. federal securities law.

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. Our six utilities serve approximately 2.3 million end-use customers.

We are also involved in several related and complementary businesses, including retail natural gas marketing to end-use customers in Georgia, Ohio and Florida; natural gas asset management and related logistics activities for each of our utilities as well as for non-affiliated 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 non-operating corporate segment.

Proposed Merger with Nicor

In December 2010, we entered into an Agreement and Plan of Merger (the Merger Agreement) with Nicor. In accordance with the Merger Agreement, each share of Nicor common stock outstanding at the Effective Time (as defined in the Merger Agreement), other than shares to be cancelled, and Dissenting Shares (as defined in the Merger Agreement), will be converted into the right to receive consideration consisting of (i) $21.20 in cash and (ii) 0.8382 shares of our common stock, subject to adjustment in certain circumstances.

The completion of the proposed merger is subject to various customary conditions, including, among others (i) shareholder approval by both companies, (ii) expiration or termination of any applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, (iii) the SEC's clearance of a registration statement registering our common stock to be issued in connection with the proposed merger and (iv) receipt of all required regulatory approvals from, among others, the Illinois Commerce Commission.

The Merger Agreement contains certain termination rights for both us and Nicor, and further provides for the payment of fees and expenses upon termination under specified circumstances. The proposed merger is expected to be completed in the second half of 2011. Except for specific references to the proposed merger, the disclosures contained in this report on Form 10-K relate solely to AGL Resources.

In January 2011, we filed a joint application with Nicor to the Illinois Commerce Commission for approval of the proposed merger. The application did not request a rate increase, but did include a commitment to maintain the number of full-time equivalent employees at Nicor's natural gas utility for a period of three years following merger completion. The Illinois Commerce Commission has eleven months to act upon the application; however, we and Nicor have asked for approval of the merger by October 1, 2011.

For additional information relating to the proposed merger please see our Form 8-K filed on December 7, 2010 and the joint proxy statement / prospectus contained in the registration statement on Form S-4 filed on February 4, 2011.

Distribution Operations

Our 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 in Georgia
- Chattanooga Gas in Tennessee
- Elizabethtown Gas in New Jersey
- Elkton Gas in Maryland
- Florida City Gas in Florida
- Virginia Natural Gas in Virginia

Utility Regulation and Rate Design

Rate Structures Each utility operates subject to regulations and oversight of the state regulatory agencies in each of the six states that we serve with respect to rates charged to our customers, maintenance of accounting records and various service and safety matters. Rates charged to our customers vary according to customer class (residential, commercial or industrial) and rate jurisdiction. These agencies approve rates designed to provide us the opportunity to generate revenues to recover all prudently incurred costs, including a return on rate base sufficient to pay interest on debt and provide a reasonable return for our shareholders. Rate base generally consists of the original cost of utility plant in service, working capital 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.

For our largest utility, Atlanta Gas Light, the natural gas market was deregulated in 1997. Accordingly, Marketers, rather than a traditional utility, sell natural gas to end-use customers in Georgia and handle customer billing functions. The Marketers file their rates monthly with the Georgia Commission. As a result of operating in a deregulated environment, 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
- planning and contracting for capacity on interstate transportation and storage systems

Atlanta Gas Light earns revenue by charging rates to its customers based primarily on monthly fixed charges that are periodically adjusted. The Marketers add these fixed charges to customer bills. This mechanism, called a straight-fixed-variable rate design minimizes the seasonality of Atlanta Gas Light’s revenues since the monthly fixed charge is not volumetric or directly weather dependent.

With the exception of Atlanta Gas Light, 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. Specifically, customer demand substantially increases during the Heating Season when natural gas is used for heating purposes. Various mechanisms such as weather normalization mechanisms exist at most of our utilities that limit our exposure to weather changes within typical ranges in all of our jurisdictions.

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All of our utilities, excluding Atlanta Gas Light, are authorized to use natural gas cost recovery mechanisms that allow 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. Since Atlanta Gas Light does not sell natural gas directly to its end-use customers, it does not need or utilize a natural gas cost recovery mechanism.

In traditional rate designs, utilities recover a significant portion of their fixed customer service and pipeline infrastructure costs based on assumed natural gas volumes used by our customers. Four of our utilities have “decoupled” regulatory mechanisms in place that encourage conservation. We believe that separating, or decoupling, the recoverable amount of these fixed costs from the customer throughput volumes, or amounts of natural gas used by our customers, allows us to encourage our customers’ energy conservation and ensures a more stable recovery of our fixed costs.

Recent Regulatory Actions In May 2010, the Tennessee Authority approved new base rates for Chattanooga Gas, which went into effect in June 2010. These new rates include energy-efficiency and conservation programs, as well as a mechanism to recover lost revenue resulting from these programs, updated depreciation rates that resulted in decreased depreciation expense of $2 million annually, and the recovery of approximately $1 million in prior legal expenses. The approved rate adjustment includes a reduction in the authorized return on equity from 10.3% to 10.05%. This decoupled rate design is the first such program for a utility in Tennessee.

In October 2010, the Georgia Commission voted and approved an annual increase of $27 million in base rate revenues for Atlanta Gas Light which became effective in November 2010. These new rates are reflected in Atlanta Gas Light’s base rate charges assessed to customers by their Marketer.

The Georgia Commission also adopted a new acquisition synergy sharing policy that allows Atlanta Gas Light to recover 50% of net synergy savings achieved on future acquisitions for a period of ten years. The policy also allows Atlanta Gas Light to recover, through December 2015, 25%, or $4 million annually, in acquisition synergy savings it continues to achieve from the 2004 NUI acquisition.

The annual rate increase also includes approximately $10 million in new customer service and safety oriented programs which Atlanta Gas Light will invest in technology and hire additional employees to support the programs. The decision also restores a standard depreciation methodology used to calculate net salvage value of utility assets, resulting in an increase in depreciation expenses of approximately $2 million.

In February 2011, Virginia Natural Gas filed a rate case with the Virginia Commission, seeking a net increase in revenues of $25 million. This requested rate increase is primarily the result of our infrastructure investments over the past ten years, including the Hampton Roads pipeline project and operational cost increases. The rate case requested a 10.95% return on equity and an authorized equity to total capitalization ratio of 51%. In order to mitigate the impact of the proposed rate increase on customer bills, we are proposing an alternative rate schedule that would phase in the Hampton Roads pipeline project capital recovery into base rates over a three year period. We expect the Virginia Commission to make a decision on this rate case within 12-18 months of our filing. New rates could go into effect, subject to refund, on August 1, 2011.

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The following table provides regulatory information for our largest utilities.

| | Atlanta Gas Light | | Elizabethtown Gas | | Virginia Natural Gas | | Florida City Gas | | Chattanooga Gas | |
|---|---|---|---|---|---|---|---|---|---|---|
| Authorized return on rate base (1) | 8.10 | % | 7.64 | % | 9.24 | % | 7.36 | % | 7.41 | % |
| Estimated 2010 return on rate base (2) | 7.26 | % | 7.87 | % | 8.24 | % | 5.04 | % | 8.98 | % |
| Authorized return on equity (1) | 10.75 | % | 10.30 | % | 10.90 | % | 11.25 | % | 10.05 | % |
| Estimated 2010 return on equity (2) | 9.10 | % | 10.76 | % | 9.62 | % | 6.22 | % | 13.45 | % |
| Authorized rate base % of equity (1) | 51.0 | % | 47.9 | % | 52.4 | % | 36.8 | % | 46.06 | % |
| Rate base included in 2010 return on equity (in millions) (3) | $ 1,312 | | $ 435 | | $ 502 | | $ 164 | | $ 91 | |
| Performance based rates (4) | | | | | ü | | | | | |
| Weather normalization (5) | | | ü | | ü | | | | ü | |
| Decoupled or straight-fixed-variable rates (6) | ü | | | | ü | | | | ü | |
| Regulatory infrastructure program rates (7) | ü | | ü | | | | | | | |
| Synergy sharing policy (8) | ü | | | | | | | | | |
| Last decision on change in rates | Oct 2010 | | Dec 2009 | | July 2006 | | N/A | | May 2010 | |

(1) The authorized return on rate base, return on equity, and percentage of equity were those authorized as of December 31, 2010.

(2) Estimates based on principles consistent with utility ratemaking in each jurisdiction.

(3) Estimated based on 13-month average.

(4) Involves frozen rates.

(5) Involves regulatory mechanisms that allow us to recover our costs in the event of unseasonal weather, but are not direct offsets to the potential impacts of weather and customer consumption on earnings. These mechanisms 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.

(6) Decoupled and straight-fixed-variable rate designs allow for the recovery of fixed customer service costs separately from assumed natural gas volumes used by our customers.

(7) Includes programs that update or expand our distribution systems and liquefied natural gas facilities. These programs include the program at Atlanta Gas Light and the utility infrastructure program at Elizabethtown Gas.

(8) Involves the recovery of a portion of net synergy savings achieved on future acquisitions.

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. The following table provides more information on the costs related to remediation of our former operating sites.

| In millions | Cost estimate range | Amount recorded | Expected costs over next twelve months |
|---|---|---|---|
| Georgia and Florida | $ 57 - $105 | $ 57 | $ 3 |
| New Jersey | | 75 | 10 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | 75 - 138 | | | | | |
| North Carolina | | 11 - 16 | | 11 | | 1 | |
| Total | $ | 143 - $259 | $ | 143 | $ | 14 | |

We report these estimates on an undiscounted basis. As we continue to conduct the actual remediation and enter into 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 regularly attempt to refine and update these engineering estimates. We primarily recover these costs through rate riders.

See item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, "Critical Accounting Estimates", for additional information about our environmental remediation liabilities. Also see Item 8, "Financial Statements and Supplementary Data", and Note 10, "Commitment and Contingencies", for information on our environmental remediation efforts.

Competition and Customer Demand

All of our utilities face competition from other energy products. Our principal competition is from electric utilities and oil and propane providers serving the residential and commercial markets throughout our service areas. Additionally, the potential displacement or replacement of natural gas appliances with electric appliances is a competitive factor.

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 commercial construction and
- new housing starts.

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While there has been some improvement in the economic conditions within the areas we serve, there continue to be high rates of unemployment and depressed housing markets with high inventories, significantly reduced new home construction and a slow-down in new commercial development. As a result, we have experienced slight customer losses in our distribution operations segment.

Our year-over-year consolidated utility customer loss rate was (0.1)% in 2010, compared to (0.3)% for 2009. We anticipate overall competition and customer trends in 2011 to be similar to our 2010 results.

We continue to mitigate the effects of the current economic conditions on our business through our use of a variety of targeted marketing programs designed to attract new customers and to retain existing customers. These efforts include working to add residential customers, multifamily complexes and commercial customers who use natural gas for purposes other than space heating, as well as evaluating and launching new natural gas related programs, products and services to enhance customer growth, mitigate customer attrition and increase operating revenues.

These programs generally emphasize natural gas as the fuel of choice for customers and seek to expand the use of natural gas through a variety of promotional activities. In addition, we partner with numerous third-party entities such as builders, realtors, plumbers, mechanical contractors, architects and engineers to market the benefits of natural gas appliances and to identify potential retention options early in the process for those customers who might consider converting to alternative fuels.

We work with regulators and state agencies in each of our jurisdictions to educate customers throughout the year about energy costs in advance of the Heating Season, and to ensure that those customers qualifying for the Low Income Home Energy Assistance Program and other similar programs receive any needed assistance and we expect to continue this focus for the foreseeable future. We have also worked with the Virginia Commission and the New Jersey BPU to educate our customers about energy efficiency and conservation and to provide rebates and other incentives for the purchase of high-efficiency natural gas-fueled equipment.

Capital Projects

We continue to focus on capital discipline and cost control, while moving ahead with projects and initiatives that we expect will have current and future benefits, provide an appropriate return on invested capital and ensure the safety, reliability and integrity of our utility infrastructure. The table below and the following discussions provide updates on some of our larger capital projects at our distribution operations segment. Our anticipated expenditures for these programs in 2011 are discussed in 'Liquidity and Capital Resources' under the caption 'Cash Flows from Financing Activities'.

| In millions | Expenditures in 2010 | Anticipated completion |
|---|---|---|
| Pipeline replacement program | $ 81 | 2013 |
| Integrated System Reinforcement Program | 54 | 2012 |
| Integrated Customer Growth Program | 5 | 2012 |
| Enhanced infrastructure program | 46 | 2011 |
| Total | $ 186 | |

Atlanta Gas Light In October 2009, the Georgia Commission approved Atlanta Gas Light's STRIDE program. As approved, STRIDE is comprised of the ongoing pipeline replacement program, which was started in 1998 and the new Integrated System Reinforcement Program (i-SRP).

The purpose of the i-SRP program under STRIDE is to upgrade Atlanta Gas Light's distribution system and liquefied natural gas facilities in Georgia, improve its system reliability and operational flexibility, and create a platform to meet long-term forecasted growth. Under STRIDE, Atlanta Gas Light is required to file an updated ten-year forecast of infrastructure requirements under i-SRP along with a new three-year construction plan every three years for review and approval by the Georgia Commission.

In January 2010, the Georgia Commission also approved the Integrated Customer Growth Program (i-CGP) under STRIDE which authorized Atlanta Gas Light to extend Atlanta Gas Light's pipeline facilities to serve customers without pipeline access and create new economic development opportunities in Georgia.

Elizabethtown Gas In 2009, the New Jersey BPU approved an accelerated enhanced infrastructure program, which was created in response to the New Jersey Governor's request for utilities to assist in the economic recovery by increasing infrastructure investments. A regulatory cost recovery mechanism has been established whereby estimated rates go into effect at the beginning of each year. At the end of the program the regulatory cost recovery mechanism will be trued-up and any remaining costs not previously collected will be included in base rates. In December 2010, Elizabethtown Gas made a request to the New Jersey BPU to spend an additional $40 million under this program to be spent in 2011 and 2012. The outcome of this request is still pending.

Glossary of Key Terms

Collective Bargaining Agreements

The following table provides information about our natural gas utilities' collective bargaining agreements.

| | # of Employees | Contract Expiration Date |
|---|---|---|
| Virginia Natural Gas | | |
| International Brotherhood of Electrical Workers (Local No. 50) | 125 | May 2012 |
| Elizabethtown Gas | | |
| Utility Workers Union of America (Local No. 424) | 167 | Nov 2011 |
| Total | 292 | |

Our current collective bargaining agreements do not require our participation in multiemployer retirement plans and we have no obligation to contribute to any such plans. These agreements represent approximately 11% of our total employees and we believe that our relations with them are good.

Retail Energy Operations

Our retail energy operations segment consists of SouthStar, a joint venture currently owned 85% by our subsidiary, Georgia Natural Gas Company, and 15% 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. SouthStar also serves retail customers in Ohio and Florida and markets natural gas to larger commercial and industrial customers in Alabama, Tennessee, North Carolina, South Carolina, Florida and Georgia.

SouthStar expanded into the Ohio market in 2006, principally through being awarded supply agreements using retail choice programs. We continue to monitor and evaluate other states where natural gas choice programs may offer potential future markets and sources for growth.

Prior to January 1, 2010, we owned a 70% interest in SouthStar and Piedmont owned 30%. However, in July 2009, we entered into an amended joint venture agreement with Piedmont pursuant to which we purchased an additional 15% ownership interest for $58 million, effective January 1, 2010, thus increasing our interest to 85%. Prior to the effectiveness of our ownership increase, SouthStar's earnings for customers in Georgia were allocated 75% to us and 25% to Piedmont, while its earnings for customers in Ohio and Florida were allocated 70% to us and 30% to Piedmont. Earnings are now allocated entirely in accordance with the ownership interests. We have no contractual rights to acquire Piedmont's remaining 15% ownership interests.

SouthStar is governed by an executive committee, which is comprised of six members, three representatives from AGL Resources and three from Piedmont. Under the joint venture agreement, all significant management decisions require the unanimous approval of the SouthStar executive committee; accordingly, our 85% financial interest is considered to be noncontrolling. We record the earnings allocated to Piedmont as a noncontrolling interest in our Consolidated Statements of Income, and we record Piedmont's portion of SouthStar's capital as a noncontrolling interest in our Consolidated Statements of Financial Position.

SouthStar's operations are sensitive to seasonal weather, natural gas prices, customer growth and consumption patterns similar to those affecting our utility operations. SouthStar's retail pricing strategies and the use of a variety of hedging strategies, such as the use of futures, options, swaps, weather derivative instruments and other risk management tools, help to ensure retail customer costs are covered to mitigate the potential effect of these issues and commodity price risk on its operations. For more information on SouthStar's energy marketing and risk management activities, see Item 7A, "Quantitative and Qualitative Disclosures About Market Risk - Commodity Price Risk."

Competition SouthStar competes with other energy Marketers to provide natural gas and related services to customers in Georgia and the Southeast. In the Georgia market, SouthStar is the largest of eleven Marketers, with average customers of approximately 500,000 over the last three years and market share of 33%.

In recent years, increased competition and the heavy promotion of fixed price plans by SouthStar's competitors has resulted in increased pressure on retail natural gas margins. In response to these market conditions SouthStar's residential and commercial customers have been migrating to fixed price plans, which, combined with increased competition from other Marketers, has impacted SouthStar's customer growth as well as margins.

In addition, similar to our natural gas utilities, SouthStar faces competition based on customer preferences for natural gas compared to other energy products and the comparative prices of those products. Natural gas price volatility in the wholesale natural gas commodity market has also contributed to an increase in competition for residential and commercial customers. SouthStar continues to use a variety of targeted marketing programs to attract new customers and to retain existing customers.

Operations SouthStar generates revenues primarily in three ways. The first is through the sale of natural gas to residential, commercial and industrial customers, primarily in Georgia where SouthStar captures a spread between wholesale and retail natural gas prices.

The second way SouthStar generates revenues 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.

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The third way SouthStar generates revenues 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 from Atlanta Gas Light that is used to supply natural gas to its customers in Georgia. Through hedging transactions, SouthStar manages exposures arising from changing commodity prices by 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.

Wholesale Services

Our wholesale services segment consists primarily of Sequent, our wholly-owned subsidiary involved in asset management and optimization, storage, transportation, producer and peaking services and wholesale marketing. The wholesale services segment also includes our wholly-owned subsidiary Compass Energy (Compass), which we acquired in 2007. Compass provides natural gas supply and services to commercial, industrial and governmental customers primarily in Kentucky, Ohio, Pennsylvania, Virginia and West Virginia. Compass contributed $2 million of EBIT in 2010 and zero in 2009.

Sequent utilizes a portfolio of natural gas storage assets, contracted supply from all of the major producing regions, as well as contracted storage and transportation capacity across the Gulf Coast, Eastern, Midwestern and Western sections of the United States and Canada to provide these services to its customers, consisting primarily of electric and natural gas utilities, power generators and large industrial customers. Sequent's logistical expertise enables it to provide its customers with natural gas from the major producing regions and market hubs in the United States and Canada and meet its delivery requirements and customer obligations at competitive prices by leveraging its portfolio of natural gas storage assets and contracted natural gas supply, transportation and storage capacity.

Sequent's portfolio of storage and transportation capacity also enables it to generate additional operating margin by optimizing the contracted assets through the application of its wholesale market knowledge and risk management skills as the opportunities arise in the Gulf Coast, Eastern, Midwestern and Western sections of the United States and Canada. These asset optimization opportunities focus on capturing the value from idle or underutilized assets, typically by participating in transactions to take advantage of volatility in pricing differences between varying geographic locations and time horizons (location and seasonal spreads) within the natural gas supply, storage and transportation markets to generate earnings. Sequent seeks to mitigate the commodity price and volatility risks and protect its operating margin through a variety of risk management and economic hedging activities.

Sequent's earnings are largely impacted by volatility in the natural gas marketplace. Volatility arises from a number of factors such as weather fluctuations or the change, supply, or demand for natural gas in different regions of the country. In December 2010, cold weather in the Northeast and Mid-Atlantic sections of the United States created not only customer demand for natural gas but also volatility, enabling Sequent to generate a large portion (approximately 25%) of its full year 2010 operating margin.

While this cold weather in December 2010 contributed to volatility in the marketplace, overall Sequent experienced reduced volatility in 2010 and continues to expect lower volatility brought on by a robust natural gas supply and ample storage in the market. This volatility is partially reflected in the year-over-year $14 million decline in economic value or operating revenues expected to be recorded in future periods associated with its existing natural gas storage inventory as discussed under energy marketing activities, as well as its transportation portfolio. Also contributing to the year-over-year decline is the impact of decreased gains on the derivative financial instruments used to hedge Sequent's storage and transportation positions.

Competition Sequent competes for asset management, long-term supply and seasonal peaking service contracts with other energy wholesalers, often through a competitive bidding process. Sequent is able to price competitively by utilizing its portfolio of contracted storage and transportation assets and by renewing and adding new contracts at prevailing lower rates. Sequent will further continue to broaden its market presence in the Pacific Northwest section of the United States and Canada, as well as pursue additional opportunities with power generation companies located in the areas of the country it operates. Sequent is also focused on building its fee based services in part to have a source of operating margin that is less impacted by volatility in the marketplace.

Asset Management Transactions Sequent's asset management customers include affiliated and 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 exceed their actual requirements. Sequent enters into structured agreements with these customers, whereby Sequent, on behalf of the customers, 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.

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Sequent has entered into asset management agreements with our affiliated utilities that include profit sharing mechanisms and fixed fee payments that require Sequent to make aggregate annual minimum payments of $10 million in 2011. These agreements are scheduled to expire over the next three years. The following table provides payments made under these agreements during the last three years.

| | Profit sharing / fee payments | | |
|---|---|---|---|
| In millions | 2010 | 2009 | 2008 |
| Atlanta Gas Light | $ 4 | $ 16 | $ 9 |
| Elizabethtown Gas | 10 | 11 | 5 |
| Chattanooga Gas | 4 | 4 | 4 |
| Virginia Natural Gas | 5 | 7 | 2 |
| Florida City Gas | 1 | 1 | 1 |
| Total | $ 24 | $ 39 | $ 21 |

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 lowest-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 and lock-in a margin on future transportation activities. The hedging instruments are derivatives, and Sequent reflects changes in the derivatives' fair value in its reported operating results in the period of change, which can be in periods prior to actual utilization of the transportation capacity.

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. Sequent provides producers with certain logistical and risk management services that offer them attractive options to move their supply into the pipeline grid.

Natural Gas Storage Inventory and Transactions Sequent maintains natural gas storage balances for volumes associated with energy marketing activities and parked gas transactions and records these within natural gas stored underground inventory on our Consolidated Statement of Financial Position. Further and generally in connection with non-affiliated asset management transactions, Sequent's recorded natural gas stored underground inventory includes volumes of natural gas it manages for its customers by purchasing the natural gas inventory from and physically delivering volumes of natural gas back to its customers based on specific delivery dates. The cost at which Sequent purchases the volumes of natural gas from its customers or WACOG is also the same price at which Sequent sells the natural gas volumes to the customer. Consequently, Sequent makes no margin on the purchase and sale of the natural gas but makes operating margin through its natural gas storage optimization activities of these volumes under management. As of December 31, 2010, Sequent has recorded $283 million of natural gas stored underground inventory within our Consolidated Statement of Financial Position, representing 68 Bcf at an overall WACOG of $4.16.

Energy Marketing Activities 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 anticipates 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 OTC derivatives in forward months to substantially lock in the operating revenue 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 operating revenue to be realized at the time the physical gas is withdrawn from storage and sold and the derivative instrument used to economically hedge natural gas price risk on that physical storage is settled. Second is the GAAP reported value both in periods prior to and in the period of physical withdrawal and sale of inventory. The GAAP amount is affected by the process of accounting for the financial hedging instruments in interim periods at fair value between the period when the natural gas is injected into storage and when it is ultimately withdrawn and the derivative 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 revenue is essentially unchanged from the date the transactions were initiated. 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.

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Sequent's 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. Sequent's expected operating revenues are net of the estimated impact of profit sharing under our asset management agreements and reflect the amounts that are realizable in future periods based on the inventory withdrawal schedule and forward natural gas prices at December 31, 2010 and 2009. A portion of Sequent's storage inventory is economically hedged with futures contracts, which results in realization of a substantially fixed margin, timing notwithstanding.

| | Withdrawal schedule (in Bcf) | | |
|---|---|---|---|
| | Salt-dome (WACOG $3.70) | Reservoir (WACOG $3.74) | Expected operating revenues (in millions) |
| 2011 | | | |
| First quarter | 2 | 22 | $ 13 |
| Second quarter | 1 | 1 | 1 |
| Third quarter | - | 1 | 1 |
| Fourth quarter | 1 | - | 1 |
| Total at Dec. 31, 2010 | 4 | 24 | $ 16 |
| Total at Dec. 31, 2009 | - | 19 | $ 30 |

If Sequent's storage withdrawals associated with existing inventory positions are executed as planned, it expects operating revenues from storage withdrawals of approximately $16 million during the next twelve months. This will change as Sequent adjusts its daily injection and withdrawal plans in response to changes in market conditions in future months and as forward NYMEX prices fluctuate.

For more information on Sequent's energy marketing and risk management activities, see Item 7A, "Quantitative and Qualitative Disclosures About Market Risk - Commodity Price Risk."

Park and Loan Transactions Sequent routinely enters into park and loan transactions with various pipelines and storage facilities, which allow Sequent 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. For these services, Sequent charges rates which include the retention of natural gas lost and unaccounted for in-kind. The economics of these transactions are evaluated and price risks are managed in much the same way as traditional reservoir and salt-dome storage transactions are evaluated and managed.

Sequent enters into forward NYMEX contracts to hedge the natural gas price risk associated with 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. Once gas is delivered under the park and loan transaction, earnings volatility is essentially eliminated since the park and loan transaction contains an embedded derivative, which is also marked to market and would substantially offset subsequent changes in value of the forward NYMEX contracts used to hedge the park and loan transaction.

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 caverns and other storage assets in the Gulf Coast region of the United States.

While this business can also generate additional revenue during times of peak market demand for natural gas storage services, the majority of our natural gas storage facilities are covered under a portfolio of short, medium and long-term contracts at a fixed market rate. We generally have had approximately 90% to 95% of Jefferson Island's working natural gas capacity under firm subscription. As Golden Triangle Storage begins full commercial operations during the first quarter of 2011, it will market its remaining available working natural gas capacity taking into consideration the prevailing market conditions in establishing rates and tenor of capacity contracts.

Jefferson Island This wholly-owned subsidiary operates a salt-dome storage and hub facility in Louisiana, approximately eight miles from the Henry Hub. It currently consists of two salt-dome storage caverns with 7.5 Bcf of working gas capacity, 0.7 Bcf per day of withdrawal capacity and 0.4 Bcf per day of injection capacity. The storage facility is regulated by the Louisiana Department of Natural Resources and by the FERC, which has regulatory authority over storage and transportation services. Jefferson Island provides storage and hub services through its direct connection to the Henry Hub and its interconnections with eight pipelines in the area. Jefferson Island currently has 6.9 Bcf under firm subscription, which represents approximately 92% of its working natural gas capacity. This level of firm subscription has remained consistent over the last three years.

In December 2009, the Louisiana Mineral and Energy Board approved an operating agreement between Jefferson Island and the State of Louisiana. In June 2010, Jefferson Island filed a permit application with the Louisiana Department of Natural Resources to expand its natural gas storage facility through the addition of two caverns. Despite the opposition of a local group, we anticipate receiving approval during the second half of 2011. When completed the additional two caverns would expand the total working gas capacity at Jefferson Island from 7.5 Bcf to approximately 19.5 Bcf of working gas capacity.

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Golden Triangle Storage Our wholly-owned subsidiary, Golden Triangle Storage, a new salt-dome storage facility in the Gulf Coast region of the United States, is designed for an initial 12 Bcf of working natural gas capacity and total cavern capacity of 18 Bcf. The facility potentially can be expanded to a total of five caverns with approximately 38 Bcf of working natural gas storage capacity in the future. The storage facility is regulated by the FERC. Golden Triangle Storage completed an approximately nine-mile dual 24” natural gas pipeline to connect the storage facility with three interstate and three intrastate pipelines.

The first cavern with 6 Bcf of working capacity began commercial service in September 2010. The second cavern, with an expected 6 Bcf of working capacity, is expected to be in service in mid-2012. Golden Triangle Storage currently has 2 Bcf under firm subscription, which represents approximately 33% of its current working natural gas capacity.

Our current estimate to complete both caverns, based on current prices for labor, materials and pad gas, is approximately $325 million. We have spent approximately $112 million in capital expenditures for this project in 2010. The actual project costs depend upon the facility’s configuration, materials, drilling costs, financing costs and 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. The costs for approximately 90% of these items have been fixed and are not subject to continued variability during construction. We are not able to predict whether these costs of construction will continue to increase, moderate or decrease from current levels, as there could be continued volatility in the construction cost estimates.

Competition Our natural gas storage facilities compete with natural gas facilities in the Gulf Coast region of the United States as the majority of the existing and proposed high deliverability salt-dome natural gas storage facilities in North America are located in the Gulf Coast region. Salt caverns have also been leached from bedded salt formations in the Northeastern and Midwestern states. Storage values have declined over the past year due to low gas prices and low volatility and we expect this to continue in 2011.

AGL Networks In July 2010, we sold AGL Networks, our telecommunication business that constructed and operated conduit fiber infrastructure within select metropolitan areas. This sale did not have a material effect on our consolidated results of operations, cash flows or financial condition.

Corporate

Our corporate segment includes our nonoperating business units. AGL Services Company is a service company we established to provide certain centralized shared services to our operating segments. We allocate substantially all of AGL Services Company’s operating expenses and interest costs to our operating segments in accordance with state regulations.

AGL Capital, our wholly-owned finance subsidiary, provides for our ongoing financing needs through a commercial paper program, the issuance of various debt and hybrid securities, and other financing arrangements. 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.

Employees

As of February 1, 2011, we had 2,621 employees.

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 12, Segment Information,” set forth in Item 8, “Financial Statements and Supplementary Data.”

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 30302-4569
404-584-4000

In Part III of this Form 10-K, we incorporate certain information by reference from our Proxy Statement for our 2011 annual meeting of shareholders. We expect to file that Proxy Statement with the SEC on or about March 14, 2011, and we will make it available on our website as soon as reasonably practicable. Please refer to the Proxy Statement when it is available.

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Additionally, our corporate governance guidelines, code of ethics, code of business conduct and the charters of each committee of our Board of Directors 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

### 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, Tennessee, New Jersey, Florida, Virginia and Maryland regulatory authorities.

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 costs associated with our regulatory infrastructure projects, including our pipeline replacement programs, and environmental remediation activities, 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 authoritative guidance related to regulated operations 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.

The Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 introduced a comprehensive new regulatory framework for swaps and security-based swaps. Although the SEC and other regulators are still in the process of adopting rules to implement the new framework, it is possible that Sequent, or other aspects of AGL Resources' operations, could be subject to the new regulations, depending on the ultimate definitions of key terms in the Dodd-Frank Act such as "swap," "swap dealer" and "major swap participant."

We could incur significant compliance costs if we must adjust to new regulations. In addition, as the regulatory environment for our industry increases in complexity, the risk of inadvertent noncompliance could also increase. If we fail to comply with applicable regulations, whether existing or new ones, 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. This may require increased use of working capital for Sequent.

In 1997, Georgia enacted legislation allowing deregulation of gas distribution operations. 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, including our majority-owned subsidiary, SouthStar, 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.

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.

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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 and improve system reliability, especially during peak usage. 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.

We may be exposed to certain regulatory and financial risks related to climate change.

Climate change is receiving ever increasing attention from scientists and legislators alike. The debate is ongoing as to the extent to which our climate is changing, the potential causes of this change and its potential impacts. Some attribute global warming to increased levels of greenhouse gases, including carbon dioxide, which has led to significant legislative and regulatory efforts to limit greenhouse gas emissions.

Presently there are no federally mandated greenhouse gas reduction requirements in the United States. However, there are a number of legislative and regulatory proposals to address greenhouse gas emissions, 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.

Any adoption by federal or state governments mandating a substantial reduction in greenhouse gas emissions could have far-reaching and significant impacts on the energy industry. We cannot predict the potential impact of such laws or regulations on our future consolidated financial condition, results of operations or cash flows.

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

Our gas distribution and storage activities involve a variety of inherent hazards and operating risks, such as leaks, accidents, including third party damages, and mechanical problems, which could cause substantial financial losses. In addition, these risks could result in serious injury to employees and non-employees, 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 which may limit our ability to grow our business.

The natural gas business is highly competitive, increasingly complex, 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.

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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.

The continuation of recent economic conditions could adversely affect our customers and negatively impact our financial results.

The slowdown in the United States economy, along with increased mortgage defaults, and significant decreases in new home construction, home values and investment assets, has adversely impacted the financial well-being of many households in the United States. We cannot predict if the administrative and legislative actions to address this situation will be successful in reducing the severity or duration of this recession. As a result, our customers may use less gas in future Heating Seasons and it may become more difficult for them to pay their natural gas bills. This may slow collections and lead to higher than normal levels of accounts receivables, bad debt and financing requirements.

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, 2010, Atlanta Gas Light had eleven certificated and active Marketers in Georgia , four of which (based on customer count and including SouthStar) accounted for approximately 31% of our consolidated operating margin for 2010. As a result, Atlanta Gas Light depends on a concentrated number of customers for revenues. The provisions of Atlanta Gas Light's tariff allow it to obtain security support in an amount equal to no less than two times a Marketer's highest month's estimated bill in the form of cash deposits, letters of credit, surety bonds or guaranties. 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. AGL Resources provides a guarantee to Atlanta Gas Light as security support for SouthStar. 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 56% of Sequent's credit exposure, excluding $61 million of customer deposits, is concentrated in its top 20 counterparties. 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 Elkton Gas where Sequent is assessed annual fixed-fees payable in monthly installments. Entry into and renewal of these agreements are subject to regulatory approval. The asset management agreement for Elizabethtown Gas expires in March 2011 and we are currently working with the New Jersey BPU to extend this agreement for an additional three years. The agreements for Atlanta Gas Light and Virginia Natural Gas are subject to renewal in March 2012. Additionally, the agreement with Florida City Gas expires in March 2013 and the agreement with Chattanooga Gas expires in March 2014.

Sequent also 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.

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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, 2010 had a 1-day holding period VaR of $1.6 million and less than $0.1 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 initiated.

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 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 10.3%.

Additionally, Virginia Natural Gas has a WNA mechanism for its residential customers that partially offsets the impacts 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 applied to the 2007 and 2008 Heating Seasons. In September 2009 the Rider was extended to September 2011.

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 stabilize the impact on its operating margin in the event of warmer or colder than normal weather in the winter months. However, these instruments do not fully protect SouthStar's earnings from the effects of unusually warm or cold 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 may 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 may 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.

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We have confirmed ten sites in Georgia and three in Florida where we own all or part of an MGP site. One additional former MGP site has been recently identified adjacent to an existing MGP remediation site. Precise engineering soil and groundwater clean up estimates are not available and considerable variability exists with this potential new site. We are required to investigate possible environmental contamination at those MGP sites and, if necessary, clean up any contamination. As of December 31, 2010, the soil and sediment remediation program was substantially complete for all Georgia sites, except for a few remaining areas of recently discovered impact, although groundwater cleanup continues. As of December 31, 2010, projected costs associated with the MGP sites associated with Atlanta Gas Light range from $57 million to $105 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 and North Carolina. 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 $75 million to $138 million. Costs have been estimated for one site in North Carolina and range from $11 million to $16 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 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 2011.

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. However, natural gas prices are expected to remain lower than they have been for the last few years as a result of a robust natural gas supply, the weak economy and ample storage.

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 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 and changes in health care cost trends.

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 other comprehensive income to the extent that the pension fund values are less than the total anticipated liability under the plans. Market declines in the second half of 2008 resulted in significant losses in the value of our pension fund assets. Although the market made a recovery in 2009 and 2010 our pension fund assets are not at the levels they were prior to the market decline in 2008. As a result, based on the current funding status of the plans, we would be required to make a minimum contribution to the plans of approximately $23 million in 2011. We are planning to make additional contributions in 2011 up to $38 million, for a total of up to $61 million, in order to preserve the current level of benefits under the plans and in accordance with the funding requirements of The Pension Protection Act of 2006 (Pension Protection Act). As of December 31, 2010 our pension plans assets represented 65% of our total pension plan obligations.

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For more information regarding some of these obligations, see Item 7, “Management's Discussion and Analysis of Financial Condition and Results of Operations” under the caption “Contractual Obligations and Commitments” and the subheading “Pension and Postretirement Obligations” and Note 5 “Employee Benefit Plans,” set forth in Item 8, “Financial Statements and Supplementary Data.”

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 negatively affected, and we may be forced to postpone, modify or cancel capital projects. 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, or
- extreme weather conditions.

The global credit markets have experienced significant disruption and volatility in recent years. While the commercial paper market has stabilized it has not returned to its pre-recession state. As of December 31, 2010, we had $732 million in commercial paper outstanding and no outstanding borrowings under our Credit Facility, Bridge Facility or Term Loan Facility. Subsequent to December 31, 2010, we drew a portion of the Term Loan Facility to help repay our senior notes that matured in January 2011.

During 2010, our borrowings under our Credit Facility along with our commercial paper were primarily used to purchase natural gas inventories for the current Heating Season. The amount of our working capital requirements in the near-term will primarily depend on the market price of natural gas and weather. Higher natural gas prices may adversely impact our accounts receivable collections and may require us to increase borrowings under our credit facility to fund our operations.

While we believe we can meet our capital requirements from our operations and our available sources of financing, we can provide no assurance that we will continue to be able to do so in the future, especially if the market price of natural gas increases significantly in the near-term. The future effects on our business, liquidity and financial results due to market disruptions could be material and adverse to us, both in the ways described above, or in ways that we do not currently anticipate.

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

Our existing Credit Facility, Bridge Facility, Term Loan 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 investment grade credit ratings. 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.

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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. In December 2010, after we announced the proposed merger with Nicor, S&P lowered our outlook from stable to negative watch, but S&P did not change our credit rating. As of December 31, 2010, if our credit rating had fallen below investment grade, we would have been required to provide collateral of approximately $39 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 may 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. For additional information, 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 derivative 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, Bridge Facility and Term Loan Facility contain cross-default provisions. 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, obligated in such instance to satisfy a large portion of our outstanding indebtedness and unable to satisfy all our outstanding obligations simultaneously.

Risks Related to Our Proposed Merger with Nicor

The merger may not be completed, which could adversely affect our business operations and stock price.

To complete the merger, our shareholders must approve the issuance of shares of our common stock as contemplated by the Merger Agreement and the amendment to our Amended and Restated Articles of Incorporation to increase the number of directors that may serve on our Board of Directors, and Nicor shareholders must approve the Merger Agreement. In addition, we and Nicor must also make certain filings with, and obtain certain other approvals and consents from, various United States federal and state governmental and regulatory authorities.

We have not yet obtained all regulatory clearances, consents and approvals required to complete the merger. Governmental or regulatory agencies could still seek to block or challenge the merger or could impose restrictions they deem necessary or desirable in the public interest as a condition to approving the merger. If these approvals are not received, or they are not received on terms that satisfy the conditions set forth in the Merger Agreement, then we will not be obligated to complete the merger.

In addition, the Merger Agreement contains other customary closing conditions which may not be satisfied or waived. If we are unable to complete the merger, we would be subject to a number of risks, including the following:

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- we would not realize the anticipated benefits of the merger, including, among other things increased operating efficiencies
- the attention of our management may have been diverted to the merger rather than to our operations and the pursuit of other opportunities that could have been beneficial to us
- the potential loss of key personnel during the pendency of the merger as employees may experience uncertainty about their future roles with the combined company
- we will have been subject to certain restrictions on the conduct of our business, which may prevent us from making certain acquisitions or dispositions or pursuing certain business opportunities while the merger is pending
  - the trading price of our common stock may decline to the extent that the current market price reflects a market assumption that the merger will be completed.

We are required to pay Nicor a termination fee and the reimbursement of merger-related out-of-pocket expenses if we terminate the merger under certain circumstances specified in the Merger Agreement.

The occurrence of any of these events individually or in combination could have a material adverse effect on our results of operations or the trading price of our common stock.

The market price of our common stock after the merger may be affected by factors different from those affecting the shares of AGL Resources or Nicor currently.

Our businesses differ from those of Nicor in important respects and, accordingly, the results of operations of the combined company and the market price of our shares of common stock following the merger may be affected by factors different from those currently affecting the results of our operations.

The merger is subject to receipt of consent or approval from governmental entities that could delay or prevent the completion of the merger or impose conditions that could have a material adverse effect on the combined company or that could cause abandonment of the merger.

To complete the merger, we and Nicor need to obtain approvals or consents from, or make filings with, a number of United States federal and state public utility, antitrust and other regulatory authorities.

While we believe that we will receive the required statutory approvals and other clearances for the merger, there can be no assurance as to the receipt or timing of receipt of these approvals and clearances. If such approvals and clearances are received, they may impose terms (i) that do not satisfy the conditions set forth in the Merger Agreement, which could permit us or Nicor to terminate the Merger Agreement or (ii) that could reasonably be expected to have a detrimental impact on the combined company following completion of the merger. A substantial delay in obtaining the required authorizations, approvals or consents or the imposition of unfavorable terms, conditions or restrictions contained in such authorizations, approvals or consents could prevent the completion of the merger or have an adverse effect on the anticipated benefits of the merger, thereby impacting the business, financial condition or results of operations of the combined company.

Even after the statutory antitrust law waiting period has expired, governmental authorities could seek to block or challenge the merger as they deem necessary or desirable in the public interest.

We are subject to contractual restrictions in the Merger Agreement that may hinder operations pending the merger.

The Merger Agreement restricts each company, without the other’s consent, from making certain acquisitions and taking other specified actions until the merger occurs or the Merger Agreement terminates. These restrictions may prevent us from pursuing otherwise attractive business opportunities and making other changes to our business prior to completion of the merger or termination of the Merger Agreement.

We will be subject to various uncertainties while the merger is pending that may cause disruption and may make it more difficult to maintain relationships with employees, suppliers, or customers.

Uncertainty about the effect of the merger on employees, suppliers and customers may have an adverse effect on us. Although we intend to take steps designed to reduce any adverse effects, these uncertainties may impair our abilities to attract, retain and motivate key personnel until the merger is completed and for a period of time thereafter, and could cause customers, suppliers and others that deal with us to seek to change or terminate existing business relationships with us or not enter into new relationships or transactions.

Employee retention and recruitment may be particularly challenging prior to the completion of the merger, as employees and prospective employees may experience uncertainty about their future roles with the combined company. If, despite our retention and recruiting efforts, key employees depart or fail to continue employment with us because of issues relating to the uncertainty and difficulty of integration or a desire not to remain with the combined company, our financial results could be adversely affected. Furthermore, the combined company's operational and financial performance following the merger could be adversely affected if it is unable to retain key employees and skilled workers. The loss of the services of key employees and skilled workers and their experience and knowledge regarding our business could adversely affect the combined company's future operating results and the successful ongoing operation of its businesses.

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Pending shareholder suits could delay or prevent the closing of the merger or otherwise adversely impact our business and operations.

Several class action lawsuits have been brought by purported Nicor shareholders challenging Nicor's proposed merger with us. The complaints allege that we aided and abetted alleged breaches of fiduciary duty by Nicor's Board of Directors. The shareholder actions seek, among other things, declaratory and injunctive relief, including orders enjoining the defendants from completing the proposed merger and, in certain circumstances, damages. No assurances can be given as to the outcome of these lawsuits, including the costs associated with defending these lawsuits or any other liabilities or costs the parties may incur in connection with the litigation or settlement of these lawsuits. Furthermore, one of the conditions to closing the merger is that there are no injunctions issued by any court preventing the completion of the transactions. No assurance can be given that these lawsuits will not result in such an injunction being issued which could prevent or delay the closing of the Merger Agreement.

The merger may not be accretive to our earnings and may cause dilution to our earnings per share, which may negatively affect the market price of our common shares.

We currently anticipate that the merger will be neutral to our earnings per share in the first full year following the completion of the merger and accretive thereafter. This expectation is based on preliminary estimates which may materially change. We may encounter additional transaction and integration-related costs, may fail to realize all of the benefits anticipated in the merger or be subject to other factors that affect preliminary estimates. Any of these factors could cause a decrease in our earnings per share or decrease or delay the expected accretive effect of the merger and contribute to a decrease in the price of our common shares.

If the merger is completed, the anticipated benefits of combining Nicor with us may not be realized.

We entered into the Merger Agreement with the expectation that the merger would result in various benefits, including, among other things, increased operating efficiencies and reduced costs.

Although we expect to achieve the anticipated benefits of the merger, achieving them is subject to a number of uncertainties, including:

- whether United States federal and state public utility, antitrust and other regulatory authorities whose approval is required to complete the merger impose conditions on the merger, which may have an adverse effect on the combined company, including its ability to achieve the anticipated benefits of the merger
- the ability of the two companies to combine certain of their operations or take advantage of expected growth opportunities
- general market and economic conditions
- general competitive factors in the marketplace
- higher than expected costs required to achieve the anticipated benefits of the merger.

No assurance can be given that these benefits will be achieved or, if achieved, the timing of their achievement. Failure to achieve these anticipated benefits could result in increased costs and decreases in the amount of expected revenues or net income of the combined company.

The integration of AGL Resources and Nicor following the merger will present significant challenges that may result in a decline in the anticipated potential benefits of the merger.

The merger involves the combination of two companies that previously operated independently. The difficulties of combining the companies' operations include:

- combining the best practices of two companies, including utility operations, non-regulated energy marketing operations and staff functions
- coordinating geographically separated organizations, systems and facilities
- integrating personnel with diverse business backgrounds and organizational cultures
- moving our operating headquarters for our gas distribution business to Naperville, Illinois
- reducing the costs associated with each company's operations
- preserving important relationships of both AGL Resources and Nicor and resolving potential conflicts that may arise.

The process of combining operations could cause an interruption of, or loss of momentum in, the activities of one or more of the combined company's businesses and the possible loss of key personnel. The diversion of management's attention and any delays or difficulties encountered in connection with the merger and the integration of the two companies' operations could have an adverse effect on the business, results of operations, financial condition or prospects of the combined company after the merger.

We will incur significant transaction, merger-related and restructuring costs in connection with the merger.

We expect to incur costs associated with combining the operations of the two companies, as well as transaction fees and other costs related to the merger. The combined company also will incur restructuring and integration costs in connection with the merger. We are in the early stages of assessing the magnitude of these costs and additional unanticipated costs may be incurred in the integration of the businesses. The costs related to restructuring will be expensed as a cost of the ongoing results of operations of either AGL Resources or Nicor or the combined company. Although we expect that the elimination of duplicative costs, as well as the realization of other efficiencies related to the integration of the businesses, may offset incremental transaction, merger-related and restructuring costs over time, any net benefit may not be achieved in the near term, or at all.

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Current shareholders will have a reduced ownership and voting interest after the merger and will exercise less influence over management of the combined company.

Upon completion of the merger we expect to issue up to approximately 38.6 million shares of common stock to Nicor shareholders in connection with the Merger Agreement. As a result, our current shareholders are expected to hold approximately 67% of the total shares of our common stock outstanding immediately following the completion of the proposed merger.

If the merger occurs, each of our shareholders will remain a shareholder of AGL Resources with a percentage ownership of the combined company that is significantly smaller than the shareholder's percentage ownership of AGL Resources prior to the merger. As a result of these reduced ownership percentages, our shareholders will have less influence on the management and policies of the combined company than they now have with respect to us.

The combined company will record goodwill that could become impaired and adversely affect the combined company's operating results.

We will account for the merger as a purchase in accordance with GAAP. Under the purchase method of accounting, the assets and liabilities of Nicor will be recorded, as of the date of completion of the merger, at their respective fair values and added to our assets and liabilities. Our reported financial condition and results of operations issued after completion of the merger will reflect Nicor balances and results after completion of the merger, but will not be restated retroactively to reflect the historical financial position or results of operations of Nicor for periods prior to the merger. Following completion of the merger, the earnings of the combined company will reflect purchase accounting adjustments.

Under the purchase method of accounting, the total purchase price will be allocated to Nicor's tangible assets and liabilities and identifiable intangible assets based on their fair values as of the date of completion of the merger. The fair value of Nicor's tangible and intangible assets and liabilities subject to the rate setting practices of their regulators approximate their carrying value. The excess of the purchase price over those fair values will be recorded as goodwill. We expect that the merger will result in the creation of goodwill based upon the application of purchase accounting. To the extent the value of goodwill or intangibles becomes impaired, the combined company may be required to incur material charges relating to such impairment. Such a potential impairment charge could have a material impact on the combined company's operating results.

Our inability to obtain the financing necessary to complete the transaction could delay or prevent the completion of the merger.

We intend to finance the cash portion of the merger consideration with debt financing. AGL Capital (as borrower) and AGL Resources (as guarantor), entered into the Bridge Facility in December 2010, which may be used to partially finance the cash portion of the merger and pay related fees and expenses in the event that permanent financing is not available at the time of the closing of the merger. AGL Resources and/or AGL Capital may issue debt securities, preferred stock, common equity, or other securities, bank loans, or other debt financings in lieu of all or a portion of the drawing under the Bridge Facility.

Under the terms of the Merger Agreement, if all of the conditions to closing are satisfied and the proceeds of the financing or alternative financing necessary to complete the transaction are not available, the Merger Agreement may be terminated by either party. However, such party is not in material breach of its representations, warranties, or covenants in the Merger Agreement. In such event, we may be required to pay Nicor a financing failure fee of $115 million.

Although we have entered into the Bridge Facility, the availability of funds under the Bridge Facility is subject to certain conditions including, among others, the absence of a material adverse effect on AGL Resources or Nicor, pro forma compliance with a consolidated total debt to total capitalization ratio of 70%, the ability of the borrower to achieve certain minimum credit ratings and the ability of the borrower to achieve a certain liquidity level at closing. Although we expect to obtain in a timely manner the financing necessary to complete the pending merger, if we are unable to timely obtain the financing because one of the conditions to the financing fails to be satisfied, the closing of the merger could be significantly delayed or may not occur at all, and we could be obligated to pay Nicor the financial failure fee.

Our indebtedness following the merger will be higher than our existing indebtedness, which could limit our operations and opportunities, make it more difficult for us to pay or refinance our debts and may cause us to issue additional equity in the future, which would increase the dilution of our shareholders or reduce earnings.

In connection with the merger, we will assume Nicor's outstanding debt and incur additional debt to pay the merger consideration and transactions expenses. Our total indebtedness as of September 30, 2010 was approximately $2.5 billion. Our pro forma total indebtedness as of September 30, 2010, after giving effect to the merger, would have been approximately $4.4 billion (including approximately $0.4 billion of currently payable long-term debt, approximately $1.0 billion of short-term borrowings and approximately $3.0 billion of long-term debt and other long-term obligations).

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Our debt service obligations with respect to this increased indebtedness could have an adverse impact on our earnings and cash flows (which after the merger would include the earnings and cash flows of Nicor) for as long as the indebtedness is outstanding.

This increased indebtedness could also have important consequences to shareholders. For example, it could:

- make it more difficult for us to pay or refinance our debts as they become due during adverse economic and industry conditions because any decrease in revenues could cause us to not have sufficient cash flows from operations to make our scheduled debt payments
- limit our flexibility to pursue other strategic opportunities or react to changes in our business and the industry in which we operate and, consequently, place us at a competitive disadvantage to competitors with less debt
- require a substantial portion of our cash flows from operations to be used for debt service payments, thereby reducing the availability of our cash flow to fund working capital, capital expenditures, acquisitions, dividend payments and other general corporate purposes
- result in a downgrade in the credit rating of our indebtedness, which could limit our ability to borrow additional funds or increase the interest rates applicable to our indebtedness (after the announcement of the merger, Standard & Poor's Ratings Services placed its long-term ratings on AGL Resources on negative watch)
- reduce the amount of credit available to us to support hedging activities
- result in higher interest expense in the event of increases in interest rates since some of our borrowings are, and will continue to be, at variable rates.

Based upon current levels of operations, we expect to be able to generate sufficient cash on a consolidated basis to make all of the principal and interest payments when such payments are due under our existing credit agreements, indentures and other instruments governing our outstanding indebtedness, and under the indebtedness of Nicor and its subsidiaries that may remain outstanding after the merger; but there can be no assurance that we will be able to repay or refinance such borrowings and obligations.

We are committed to maintaining and improving our credit ratings. In order to maintain and improve these credit ratings, we may consider it appropriate to reduce the amount of indebtedness outstanding following the merger. This may be accomplished in several ways, including issuing additional shares of common stock or securities convertible into shares of common stock, reducing discretionary uses of cash or a combination of these and other measures. Issuances of additional shares of common stock or securities convertible into shares of common stock would have the effect of diluting the ownership percentage that shareholders will hold in the combined company and might reduce the reported earnings per share. The specific measures that we may ultimately decide to use to maintain or improve our credit ratings and their timing, will depend upon a number of factors, including market conditions and forecasts at the time those decisions are made.

Following the merger, shareholders will own equity interests in a company that owns and operates a carrier shipping business, which can present unique risks.

Nicor’s ownership and operation of Tropical Shipping, a carrier of containerized freight in the Bahamas and the Caribbean region, which we anticipate will make up approximately 4% of the combined company's earnings before interest and taxes, or EBIT, will subject the combined company to various risks to which we are not currently subject. These include the costs associated with compliance with the International Ship and Port-facility Security Code and the United States Maritime Transportation Security Act, both of which require extensive security assessments, plans and procedures, regulatory oversight by the Federal Maritime Commission and the Surface Transportation Board, the effect of general economic conditions in the United States, the Bahamas, the Caribbean region and Canada on the results of operations, cash flows and financial conditions of Tropical Shipping, and the effect of weather conditions in Florida, Canada, the Bahamas and the Caribbean region on the results of operations, cash flows and financial conditions of Tropical Shipping. As shareholders of the combined company following the merger, our shareholders may be adversely affected by these risks.

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

We consider our properties to be well maintained, in good operating condition and suitable for their intended purpose. The following provides the location and general character of the materially important properties that are used by our segments.

Distribution and transmission assets

At December 31, 2010, our distribution operations and energy investment segments owned approximately 46,000 miles of underground distribution and transmission mains. Our distribution networks transport natural gas from our pipeline suppliers to our customers in our service areas. The distribution and transmission mains are located on easements or rights-of-way which generally provide for perpetual use.

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Storage assets

We have approximately 7.5 Bcf of LNG storage capacity in five LNG plants located in Georgia, New Jersey and Tennessee. In addition, we own two propane storage facilities in Virginia that have a combined storage capacity of approximately 0.5 Bcf. The LNG plants and propane storage facilities are used by distribution operations to supplement natural gas supply during peak usage periods.

We currently own two high-deliverability natural gas storage and hub facilities which are operated by our energy investments segment. Our wholly-owned subsidiary, Jefferson Island, is located in Louisiana and contains two salt dome gas storage caverns with approximately 10 Bcf of total capacity and about 8 Bcf of working gas capacity. Our wholly-owned subsidiary, Golden Triangle Storage, is located in Texas and is designed for 12 Bcf of working natural gas capacity and total cavern capacity of 18 Bcf. The first cavern with 6 Bcf of working capacity was completed and began commercial service in September 2010. The second cavern with an expected 6 Bcf of working capacity is expected to be placed into commercial service in mid 2012. Our energy investments segment also owns a propane storage facility in Virginia with approximately 0.3 Bcf of storage capacity. This facility supplements the natural gas supply to our Virginia utility during peak usage periods.

Offices

All of our segments own or lease office, warehouse and other facilities throughout our operating areas. 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.

We have been named as a defendant in several class action lawsuits brought by purported Nicor shareholders challenging Nicor’s proposed merger with us. The complaints allege that we aided and abetted alleged breaches of fiduciary duty by Nicor’s Board of Directors. The shareholder actions seek, among other things, declaratory and injunctive relief, including orders enjoining the defendants from completing the proposed merger and, in certain circumstances, damages. We believe the claims asserted in each lawsuit to be without merit and intend to vigorously defend against them.

For more information regarding some of these proceedings, see Note 10 to our consolidated financial statements under the caption “Litigation.”

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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 AGL. At February 7, 2011, there were 9,277 record holders of our common stock. Quarterly information concerning our high and low stock prices and cash dividends paid in 2010 and 2009 is as follows:

| | Sales price of common stock | | Cash dividend per common | | Sales price of common stock | | Cash dividend per common |
|---|---|---|---|---|---|---|---|
| Quarter ended: | High | Low | share | Quarter ended: | High | Low | share |
| March 31, 2010 | $ 38.83 | $ 34.26 | $ 0.44 | March 31, 2009 | $ 34.93 | $ 24.02 | $ 0.43 |
| June 30, 2010 | 40.08 | 34.72 | 0.44 | June 30, 2009 | 32.38 | 26.00 | 0.43 |
| September 30, 2010 | 40.00 | 35.29 | 0.44 | September 30, 2009 | 35.79 | 30.05 | 0.43 |
| December 31, 2010 | 39.66 | 34.21 | 0.44 | December 31, 2009 | 37.52 | 33.50 | 0.43 |
| | | | $ 1.76 | | | | $ 1.72 |

We have historically paid dividends to common shareholders four times a year: March 1, June 1, September 1 and December 1. We have paid 252 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 covenants
- our ability to satisfy our obligations to any future 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, 2010. 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 currently anticipate holding the repurchased shares as treasury shares.

| Period | Total number of shares purchased (1) (2) | Average price paid per common share | Total number of shares purchased as part of publicly announced plans or programs (2) | Maximum number of shares that may yet be purchased under the publicly announced plans or programs (2) |
|---|---|---|---|---|
| October 2010 | - | $ - | - | 4,825,251 |
| November 2010 | 5,000 | 27.41 | - | 4,825,251 |
| December 2010 | 63,750 | 35.77 | 63,750 | 4,761,501 |
| Total fourth quarter | 68,750 | $ 35.16 | 63,750 | |

(1) 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 purchased 5,000 shares for such purposes in the fourth quarter of 2010. As of December 31, 2010, we had purchased a total 347,153 of the 600,000 shares authorized for purchase, leaving 252,847 shares available for purchase under this program.

(2) 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 (1) above, over a five-year period. This repurchase plan expired January 31, 2011. However, we may request that our Board of Directors extend this plan.

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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 | 2010 | 2009 | 2008 | 2007 | 2006 |
|---|---|---|---|---|---|
| Income statement data | | | | | |
| Operating revenues | $ 2,373 | $ 2,317 | $ 2,800 | $ 2,494 | $ 2,621 |
| Cost of gas | 1,164 | 1,142 | 1,654 | 1,369 | 1,482 |
| Operating margin (1) | 1,209 | 1,175 | 1,146 | 1,125 | 1,139 |
| Operating expenses | | | | | |
| Operation and maintenance | 503 | 497 | 472 | 451 | 473 |
| Depreciation and amortization | 160 | 158 | 152 | 144 | 138 |
| Taxes other than income taxes | 46 | 44 | 44 | 41 | 40 |
| Total operating expenses | 709 | 699 | 668 | 636 | 651 |
| Operating income | 500 | 476 | 478 | 489 | 488 |
| Other (expense) income | (1) | 9 | 6 | 4 | (1) |
| Earnings before interest and taxes (EBIT) (1) | 499 | 485 | 484 | 493 | 487 |
| Interest expenses | 109 | 101 | 115 | 125 | 123 |
| Earnings before income taxes | 390 | 384 | 369 | 368 | 364 |
| Income taxes | 140 | 135 | 132 | 127 | 129 |
| Net income | 250 | 249 | 237 | 241 | 235 |
| Less net income attributable to the noncontrolling interest | 16 | 27 | 20 | 30 | 23 |
| Net income attributable to AGL Resources Inc. | $ 234 | $ 222 | $ 217 | $ 211 | $ 212 |
| Common stock data | | | | | |
| Weighted average common shares outstanding basic | 77.4 | 76.8 | 76.3 | 77.1 | 77.6 |
| Weighted average common shares outstanding diluted | 77.8 | 77.1 | 76.6 | 77.4 | 78.0 |
| Total shares outstanding (2) | 78.1 | 77.5 | 76.9 | 76.4 | 77.7 |
| Basic earnings per common share attributable to AGL Resources Inc. common shareholders | $ 3.02 | $ 2.89 | $ 2.85 | $ 2.74 | $ 2.73 |
| Diluted earnings per common share – attributable to AGL Resources Inc. common shareholders | $ 3.00 | $ 2.88 | $ 2.84 | $ 2.72 | $ 2.72 |
| Dividends declared per common share | $ 1.76 | $ 1.72 | $ 1.68 | $ 1.64 | $ 1.48 |
| Dividend payout ratio | 58 % | 60 % | 59 % | 60 % | 54 % |
| Dividend yield (3) | 4.9 % | 4.7 % | 5.4 % | 4.4 % | 3.8 % |
| Price range: | | | | | |
| High | $ 40.08 | $ 37.52 | $ 39.13 | $ 44.67 | $ 40.09 |
| Low | $ 34.21 | $ 24.02 | $ 24.02 | $ 35.24 | $ 34.40 |
| Close (2) | $ 35.85 | $ 36.47 | $ 31.35 | $ 37.64 | $ 38.91 |
| Market value (2) | $ 2,800 | $ 2,826 | $ 2,411 | $ 2,876 | $ 3,023 |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Statements of Financial Position data (2) | | | | | | | | | | | | | | |
| Total assets | $ | 7,518 | | $ | 7,074 | | $ | 6,710 | | $ | 6,258 | | $ | 6,123 |
| Property, plant and equipment – net | | 4,405 | | | 4,146 | | | 3,816 | | | 3,566 | | | 3,436 |
| Total debt | | 2,706 | | | 2,576 | | | 2,541 | | | 2,255 | | | 2,161 |
| Total equity | | 1,836 | | | 1,819 | | | 1,684 | | | 1,708 | | | 1,651 |
| Cash flow data | | | | | | | | | | | | | | |
| Net cash flow provided by operating activities | $ | 526 | | $ | 592 | | $ | 227 | | $ | 377 | | $ | 351 |
| Net cash flow used in investing activities | | (442 | ) | | (476 | ) | | (372 | ) | | (253 | ) | | (248 )|
| Net cash flow (used in) provided by financing activities | | (86 | ) | | (106 | ) | | 142 | | | (122 | ) | | (118 )|
| Net borrowings and (payments) of short-term debt | | 131 | | | (264 | ) | | 286 | | | 52 | | | 6 |
| Financial ratios (2) | | | | | | | | | | | | | | |
| Debt | | 60 | % | | 59 | % | | 60 | % | | 57 | % | | 57 % |
| Equity | | 40 | % | | 41 | % | | 40 | % | | 43 | % | | 43 % |
| Total | | 100 | % | | 100 | % | | 100 | % | | 100 | % | | 100 % |
| Return on average equity | | 12.8 | % | | 12.7 | % | | 12.8 | % | | 12.6 | % | | 13.3 % |

(1) These are non-GAAP measurements. A reconciliation of operating margin to operating income and EBIT to earnings before income taxes 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) Dividends declared per common share divided by market value per common share.

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

### Overview

Our 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, price levels for natural gas and general economic conditions that may impact our customers' ability to pay for gas consumed. Various mechanisms exist that limit our exposure to weather changes within specified 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.
Sequent, our wholly-owned subsidiary within our wholesale services segment is temperature insensitive, but generally has greater opportunity to capture operating margin due to price volatility as a result of extreme weather. 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. For more information on our operating segments, see Item 1, "Business".

### Executive Summary

Proposed merger with Nicor In December 2010, we entered into a Merger Agreement with Nicor, which we expect to complete in the second half of 2011. The proposed merger will create a combined company with increased scale and scope in both regulated utility and non-regulated businesses as indicated below:

- Seven regulated natural gas distribution companies providing natural gas services to approximately 4.5 million customers in Illinois, Georgia, New Jersey, Virginia, Florida, Tennessee and Maryland
- Over 1 million retail customers in the unregulated businesses
- Physical wholesale gas business delivering approximately 4.7 Bcf of natural gas per day
- Natural gas storage facilities that will provide approximately 31 Bcf of storage in 2012

Completion of the proposed merger is conditioned upon, among other things, shareholder approval by both companies, expiration or termination of any applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, and approval by, among others, the Illinois Commerce Commission. We anticipate that the necessary approvals will be obtained.

In January 2011, we filed a joint application with Nicor to the Illinois Commerce Commission for approval of the proposed merger. As stated above, approval by the Illinois Commerce Commission is a condition to completion of the merger. The application did not request a rate increase and included a commitment to maintain the number of full-time equivalent employees involved in the operation of Nicor's gas distribution subsidiary at a level comparable to current staffing for a period of three years following merger completion. The Illinois Commerce Commission has eleven months to act upon the application; however, we and Nicor have asked for approval of the merger by October 1, 2011.

The Merger Agreement contains certain termination rights for both us and Nicor, and further provides for the payment of fees and expenses upon termination under specified circumstances. For additional information relating to the proposed merger please see our Form 8-K filed on December 7, 2010. Further information concerning the proposed merger was included in a joint proxy statement/prospectus contained in the registration statement on Form S-4 that was filed with the SEC on February 4, 2011.

Legislative and regulatory update We continue to actively pursue a regulatory strategy that improves customer service and reduces the lag between our investments in infrastructure and the recovery of those investments through various rate mechanisms. If our rate design approvals are not approved, we will continue to work cooperatively with our regulators, legislators and others to create a framework that is conducive to our business goals and the interests of our customers and shareholders.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was enacted in July 2010, representing an overhaul of the framework for regulation of United States financial markets. We are currently evaluating the provisions of the Dodd-Frank Act and the potential impact that it may have on us.

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However, we believe that an aspect of the Dodd-Frank Act which requires that various regulatory agencies, including the SEC and the Commodities Futures Trading Commission, establish additional regulations for participating in financial markets for hedging certain risks inherent in our business, including commodity and interest rate risks, may be applicable to us. As a result, the costs of participating in financial markets for hedging certain risks may be increased as a result of the new legislation. We may also incur additional costs associated with our compliance with new regulations and anticipated additional reporting and disclosure obligations. For additional information on our regulatory strategy see Item 1, “Business” under the caption “Regulatory Planning”.

Customer growth initiatives Relative to recent years, we continue to see higher than normal rates of unemployment, depressed housing markets with high inventories, significantly reduced new home construction and a slow-down in new commercial development. As a result, we experienced slight customer losses in our distribution operations and retail energy operations segments throughout 2010. We have largely offset this trend by implementing customer attrition mitigation strategies to retain existing customers at all of our utilities. We expect a similar environment to prevail throughout 2011.

We use a variety of targeted marketing programs to attract new customers and to retain existing customers. These efforts include working to add residential customers, multifamily complexes and commercial customers who use natural gas for purposes other than space heating, as well as evaluating and launching new natural gas related programs, products and services to enhance customer growth, mitigate customer attrition and increase operating revenues. These programs generally emphasize natural gas as the fuel of choice for customers and seek to expand the use of natural gas through a variety of promotional activities.

Natural gas price volatility The volatility of natural gas commodity prices have a significant impact on our customer rates, our long-term competitive position against other energy sources and the ability of our wholesale services segment to capture value from location and seasonal spreads. During 2008 and 2009, daily Henry Hub spot market prices for natural gas in the United States were extremely volatile. However, during 2010, the volatility of natural gas prices was lower than it has been for the last few years as a result of a robust natural gas supply, the weak economy and ample storage. Our natural gas acquisition strategy is designed to secure sufficient supplies of natural gas to meet the needs of our utility customers and to hedge gas prices to effectively manage costs, reduce price volatility and maintain a competitive advantage. Additionally, our hedging strategies and physical natural gas supplies in storage enable us to reduce earnings risk exposure due to higher gas costs.

It is possible that natural gas prices will remain low for an extended period based on current levels of excess supply relative to market demand for natural gas, in part due to abundant sources of new shale natural gas reserves and the lack of demand by commercial and industrial enterprises. However, as economic conditions improve the demand for natural gas may increase, natural gas prices could rise and higher volatility could return to the natural gas markets.

Capital market plan Our capital market plan for the remainder of 2011 includes successfully completing offerings of approximately $1 billion in long-term debt and $1.4 billion in common stock to finance the proposed Nicor merger and maintaining our solid investment-grade credit ratings.

For additional information on our Credit Facility and our capital market plan see “Liquidity and Capital Resources” under the caption “Cash Flow from Financing Activities” and “Short-term Debt”. See also Note 7 to our consolidated financial statements.

Hedges Changes in commodity prices subject a significant portion of our operations to earnings variability. Our non-utility businesses principally use physical and financial arrangements to reduce the risks associated with both weather-related seasonal fluctuations in market conditions and changing commodity prices. These economic hedges may not qualify, or are not designated for, hedge accounting treatment. As a result, 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 revenues 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. Occasionally in the summer, Sequent's operating revenues are impacted due to peak usage by power generators in response to summer energy demands. Seasonality also affects the comparison of certain statements of financial position items such as receivables, unbilled revenue, inventories and short-term debt across quarters. However, these items are comparable when reviewing our annual results.

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Approximately 70% of these segments' operating revenues and 78% of these segments' EBIT for the year ended December 31, 2010 were generated during the first and fourth quarters of 2010, and are reflected in our Consolidated Statements of Income for the quarters ended March 31, 2010 and December 31, 2010. 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 can vary significantly from quarter to quarter as a result of seasonality.

Results of Operations

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. No individual customer or industry accounts for a significant portion of our revenues. The following table provides more information regarding the components of our operating revenues.

| In millions | 2010 | 2009 | 2008 |
|---|---|---|---|
| Residential | $ 1,083 | $ 1,091 | $ 1,194 |
| Commercial | 521 | 467 | 598 |
| Transportation | 404 | 378 | 459 |
| Industrial | 205 | 185 | 322 |
| Other | 160 | 196 | 227 |
| Total operating revenues | $ 2,373 | $ 2,317 | $ 2,800 |

We evaluate segment performance using the measures of operating margin and EBIT, which include the effects of corporate expense allocations. Operating margin is a non-GAAP measure that is calculated as operating revenues minus cost of gas, which 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 Consolidated Statements of Income. EBIT is also a non-GAAP measure that includes operating income, other income and expenses. Items that we do not include in EBIT are financing costs, including interest and debt expense and income taxes, each of which we evaluate on a consolidated basis.

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. 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 attributable to AGL Resources Inc. 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 following table reconciles operating margin to operating income and EBIT to earnings before income taxes and net income, together with other consolidated financial information for the last three years.

| In millions | 2010 | 2009 | 2008 |
|---|---|---|---|
| Operating revenues | $ 2,373 | $ 2,317 | $ 2,800 |
| Cost of gas | 1,164 | 1,142 | 1,654 |

| | | | |
|---|---|---|---|
| Operating margin | 1,209 | 1,175 | 1,146 |
| Operating expenses | 709 | 699 | 668 |
| Operating income | 500 | 476 | 478 |
| Other (expense) income | (1 ) | 9 | 6 |
| EBIT | 499 | 485 | 484 |
| Interest expenses | 109 | 101 | 115 |
| Earnings before income taxes | 390 | 384 | 369 |
| Income tax expenses | 140 | 135 | 132 |
| Net income | 250 | 249 | 237 |
| Less net income attributable to the noncontrolling interest | 16 | 27 | 20 |
| Net income attributable to AGL Resources Inc. | $ 234 | $ 222 | $ 217 |

In 2010, our net income attributable to AGL Resources Inc. increased by $12 million from the prior year primarily due to increased EBIT at distribution operations largely due to new rates at Atlanta Gas Light and Elizabethtown Gas as well as the completion of the Hampton Roads and Magnolia pipeline projects. The increase in our net income attributable to AGL Resources Inc. was also favorably impacted by increased EBIT at wholesale services and our additional 15% ownership interest in SouthStar, which was effective January 1, 2010. This was partly offset by increased interest expense and decreased EBIT at retail energy operations, energy investments and corporate. The decrease in EBIT at retail energy operations was mainly due to increased operating expenses. The decrease in EBIT at energy investments was the result of decreased operating margins mainly due to the sale of AGL Networks. The decrease in EBIT at corporate was mainly due to approximately $6 million of outside services expenses associated with non-recurring transaction costs associated with the proposed merger with Nicor.

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In 2009, our net income attributable to AGL Resources Inc. increased by $5 million from the prior year primarily due to decreased interest expense and increased EBIT from retail energy operations largely due to higher operating margin. This was partly offset by decreased EBIT at distribution operations, wholesale services and energy investments. The decrease in EBIT at distribution operations was primarily due to increased operating expenses offset by increased operating margin. The decrease in EBIT at wholesale services and energy investments was the result of decreased operating margins and increased operating expenses.

The following table provides each operating segment's percentage contribution to the total EBIT for our operating segments for the last three years.

| | 2010 | | 2009 | | | 2008 | |
|---|---|---|---|---|---|---|---|
| Distribution operations | 69 | % | 67 | % | $ | 68 | % |
| Retail energy operations | 20 | | 21 | | | 16 | |
| Wholesale services | 10 | | 10 | | | 12 | |
| Energy investments | 1 | | 2 | | $ | 4 | |
| Total EBIT | 100 | % | 100 | % | | 100 | % |

Over the last three years, on average, we have derived 69% of our operating segments' EBIT from our regulated natural gas distribution business whose rates are approved by state regulatory commissions. We derived our remaining operating segment's EBIT for the last three years principally from businesses that are complementary to our natural gas distribution business. These businesses include the sale of natural gas to retail customers, natural gas asset management and the operation of high-deliverability natural gas underground storage as ancillary activities to our regulated utility franchises.

Interest expense Our interest expense over the last three years has fluctuated primarily due to short-term interest rate changes and higher average debt levels. The following table provides additional detail on interest expense for the last three years and the primary items that affect year-over-year change.

| In millions | | 2010 | | | 2009 | | | 2008 | |
|---|---|---|---|---|---|---|---|---|---|
| Interest expense | $ | 109 | | $ | 101 | | $ | 115 | |
| Average debt outstanding (1) | $ | 2,393 | | $ | 2,239 | | $ | 2,156 | |
| Average rate | | 4.6 | % | | 4.5 | % | | 5.3 | % |

(1) Daily average of all outstanding debt.

The difficult economic conditions of the past few years have resulted in low United States Treasury yields and corresponding indexes on short-term borrowings. These factors have favorably impacted our earnings in 2010, 2009 and 2008 through reduced short-term rates that we paid on our commercial paper borrowings. For more information on the impact that interest rate fluctuations have on our variable-rate debt, see "Interest Rate Risk" in Item 7A, "Quantitative and Qualitative Disclosures About Market Risk."

Income tax expense Our income tax expense in 2010 increased by $5 million or 4% compared to 2009, and increased by $3 million or 2% in 2009 compared to 2008. These increases were primarily due to higher consolidated earnings. Our effective tax rate was 37.5% in 2010 and 37.8% in 2009 and 2008.

As a result of the authoritative guidance related to consolidations, income tax expense and our effective tax rate are determined from earnings before income taxes less net income attributable to the noncontrolling interest. For more information on our income taxes, including a reconciliation between the statutory federal income tax rate and the effective rate, see Note 11.

Operating metrics Selected weather, customer and volume metrics for 2010, 2009 and 2008, which we consider to be some of the key performance indicators for our operating segments, are presented in the following tables. We measure the effects of weather on our business through heating degree days. Generally, increased heating degree days result in greater demand for gas on our distribution systems. However, extended and unusually mild weather during the Heating Season can have a significant negative impact on demand for natural gas.

Our customer metrics highlight the average number of customers to which we provide services. This number of customers can be impacted by natural gas prices, economic conditions and competition from alternative fuels.

Volume metrics for distribution operations and retail energy operations present the effects of weather and our customers' demand for natural gas. Wholesale services' daily physical sales represent the daily average natural gas volumes sold to its customers. Within our energy investments segment, our natural gas storage businesses generally prefer to have approximately 95% of their working natural gas capacity under firm subscription. This allows our natural gas storage business to generate additional revenue during times of peak market demand for natural gas storage services, but retain consistency with their earnings.

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| Weather<br>Heating degree days (1) | Year ended December 31, | | | | 2010 vs. 2009 colder (warmer) | 2009 vs. 2008 colder (warmer) | 2010 vs. normal colder (warmer) | 2009 vs. normal colder (warmer) | 2008 vs. normal colder (warmer) |
|---|---|---|---|---|---|---|---|---|---|
| | Normal | 2010 | 2009 | 2008 | | | | | |
| Georgia | 2,682 | 3,209 | 2,803 | 2,746 | 14 % | 2 % | 20 % | 5 % | 2 % |
| New Jersey | 4,652 | 4,445 | 4,755 | 4,646 | (7 )% | 2 % | (4 )% | 2 % | - |
| Virginia | 3,203 | 3,601 | 3,312 | 3,031 | 9 % | 9 % | 12 % | 3 % | (5 )% |
| Florida | 573 | 1,108 | 548 | 416 | 102 % | 32 % | 93 % | (4 )% | (27 )% |
| Tennessee | 3,085 | 3,594 | 3,154 | 3,179 | 14 % | (1 )% | 16 % | 2 % | 3 % |
| Maryland | 4,700 | 4,679 | 4,783 | 4,519 | (2 )% | 6 % | - | 2 % | (4 )% |
| Ohio | 4,899 | 5,181 | 4,919 | 5,155 | 5 % | (5 )% | 6 % | - | 5 % |

| | Quarter ended December 31, | | | | 2010 vs. 2009 colder (warmer) | 2009 vs. 2008 colder (warmer) | 2010 vs. normal colder (warmer) | 2009 vs. normal colder (warmer) | 2008 vs. normal colder (warmer) |
|---|---|---|---|---|---|---|---|---|---|
| | Normal | 2010 | 2009 | 2008 | | | | | |
| Georgia | 1,030 | 1,187 | 1,182 | 1,092 | - | 8 % | 15 % | 15 % | 6 % |
| New Jersey | 1,616 | 1,720 | 1,618 | 1,728 | 6 % | (6 )% | 6 % | - | 7 % |
| Virginia | 1,095 | 1,380 | 1,065 | 1,151 | 30 % | (7 )% | 26 % | (3 )% | 5 % |
| Florida | 176 | 365 | 158 | 201 | 131 % | (21 )% | 107 % | (10 )% | 14 % |
| Tennessee | 1,204 | 1,382 | 1,283 | 1,291 | 8 % | (1 )% | 15 % | 7 % | 7 % |
| Maryland | 1,665 | 1,822 | 1,665 | 1,691 | 9 % | (2 )% | 9 % | - | 2 % |
| Ohio | 1,826 | 2,028 | 1,893 | 1,914 | 7 % | (1 )% | 11 % | 4 % | 5 % |

| Customers | Year ended December 31, | | | 2010 vs. 2009 % change | 2009 vs. 2008 % change |
|---|---|---|---|---|---|
| | 2010 | 2009 | 2008 | | |
| Distribution Operations | | | | | |
| Average end-use customers (in thousands) | | | | | |
| Atlanta Gas Light | 1,544 | 1,549 | 1,557 | (0.3 )% | (0.5 )% |
| Elizabethtown Gas | 274 | 273 | 273 | 0.4 | - |
| Virginia Natural Gas | 275 | 273 | 271 | 0.7 | 0.7 |
| Florida City Gas | 103 | 103 | 104 | - | (1.0 ) |
| Chattanooga Gas | 62 | 62 | 62 | - | - |
| Elkton Gas | 6 | 6 | 6 | - | - |
| Total | 2,264 | 2,266 | 2,273 | (0.1 )% | (0.3 )% |
| | | | | | |
| Retail Energy Operations | | | | | |
| Average customers (in thousands) | | | | | |
| Georgia | 496 | 504 | 526 | (2 )% | (4 )% |
| Ohio and Florida (2) | 77 | 103 | 122 | (25 )% | (16 )% |
| Total | 573 | 607 | 648 | (6 )% | (6 )% |
| Market share in Georgia | 33 % | 33 % | 34 % | - | (3 )% |

| Volumes | Year ended December 31, | 2009 vs. 2008 |
|---|---|---|

| In billion cubic feet (Bcf) | 2010 | 2009 | 2008 | 2010 vs. 2009 % change | % change |
|---|---|---|---|---|---|
| Distribution Operations | | | | | |
| Firm | 243 | 218 | 219 | 11 % | - |
| Interruptible | 99 | 98 | 104 | 1 % | (6 )% |
| Total | 342 | 316 | 323 | 8 % | (2 )% |
| | | | | | |
| Retail Energy Operations | | | | | |
| Georgia firm | 46 | 40 | 41 | 15 % | (2 )% |
| Ohio and Florida | 10 | 11 | 7 | (9 )% | 57 % |
| | | | | | |
| Wholesale Services | | | | | |
| Daily physical sales (Bcf / day) | 4.57 | 2.96 | 2.60 | 54 % | 14 % |
| | | | | | |
| Energy Investments | | | | | |
| Working natural gas capacity | 13.5 | 7.5 | 7.5 | 80 % | - |
| % of capacity under subscription | 66 % | 93 % | 93 % | (29 )% | - |

(1) Obtained from the National Oceanic and Atmospheric Administration, National Climatic Data Center. Normal represents the ten-year averages from January 2000 to December 2010.

(2) A portion of the Ohio customers represents customer equivalents, which are computed by the actual delivered volumes divided by the expected average customer usage.

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Segment information Operating margin, operating expenses and EBIT information for each of our segments are contained in the following tables for the last three years.

| In millions | Operating margin (1) | Operating expenses | EBIT (1) |
|---|---|---|---|
| 2010 | | | |
| Distribution operations | $ 882 | $ 531 | $ 355 |
| Retail energy operations | 183 | 80 | 103 |
| Wholesale services | 105 | 57 | 49 |
| Energy investments | 39 | 32 | 4 |
| Corporate (2) | - | 9 | (12 ) |
| Consolidated | $ 1,209 | $ 709 | $ 499 |
| 2009 | | | |
| Distribution operations | $ 836 | $ 519 | $ 326 |
| Retail energy operations | 181 | 76 | 105 |
| Wholesale services | 111 | 64 | 47 |
| Energy investments | 46 | 33 | 12 |
| Corporate (2) | 1 | 7 | (5 ) |
| Consolidated | $ 1,175 | $ 699 | $ 485 |
| 2008 | | | |
| Distribution operations | $ 818 | $ 493 | $ 329 |
| Retail energy operations | 149 | 73 | 77 |
| Wholesale services | 122 | 62 | 60 |
| Energy investments | 50 | 31 | 19 |
| Corporate (2) | 7 | 9 | (1 ) |
| Consolidated | $ 1,146 | $ 668 | $ 484 |

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

Distribution Operations

| In millions | 2010 | 2009 |
|---|---|---|
| EBIT – prior year | $ 326 | $ 329 |
| | | |
| Operating margin | | |
| Increased revenues from the Hampton Roads and Magnolia pipeline projects | 27 | 2 |
| Increased revenues from new rates and regulatory infrastructure program revenues at Atlanta Gas Light | 9 | 6 |
| Increased revenues from new rates and enhanced infrastructure program revenues at Elizabethtown Gas | 6 | - |
| Increased revenues from higher usage at Florida City Gas due to colder weather | 3 | - |
| (Decreased) increased margins from gas storage carrying amounts at Atlanta Gas Light | (1 ) | 8 |
| Other | 2 | 2 |
| Increase in operating margin | 46 | 18 |
| | | |
| Operating expenses | | |
| Increased pension expenses | 4 | 12 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Increased payroll and incentive expenses | | 9 | | | 12 | |
| Increased depreciation expenses | | 4 | | | 6 | |
| Increased (decreased) marketing costs | | 1 | | | (2 | ) |
| Decreased bad debt expenses | | (3 | ) | | (1 | ) |
| Decreased outside services and other expenses | | (3 | ) | | (1 | ) |
| Increase in operating expenses | | 12 | | | 26 | |
| (Decrease) increase in other income, primarily from regulatory allowance for funds used during construction of Hampton Roads pipeline project completed in 2009 | | (5 | ) | | 5 | |
| EBIT – current year | $ | 355 | | $ | 326 | |

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Retail Energy Operations

| In millions | 2010 | 2009 |
|---|---|---|
| EBIT – prior year | $ 105 | $ 77 |
| | | |
| Operating margin | | |
| Increased average customer usage and colder weather | 9 | 4 |
| Change in LOCOM adjustment | 6 | 18 |
| Increased operating margins for Florida, Ohio and interruptible customers | 1 | 5 |
| Change in retail pricing plan mix and decrease in average number of customers | (12) | (13) |
| (Decreased) increased contributions from the management and optimization of storage and transportation assets, and from retail price spreads | (1) | 15 |
| Other | (1) | 3 |
| Increase in operating margin | 2 | 32 |
| | | |
| Operating expenses | | |
| Decreased bad debt expenses | - | (1) |
| Increased legal expense, offset by lower depreciation expenses | 3 | - |
| Increased marketing and other expenses | 1 | 4 |
| Increase in operating expenses | 4 | 3 |
| Decreased other income | - | (1) |
| EBIT – current year | $ 103 | $ 105 |

Wholesale Services

| In millions | 2010 | 2009 |
|---|---|---|
| EBIT – prior year | $ 47 | $ 60 |
| | | |
| Operating margin | | |
| Change in storage hedge gains as a result of declining NYMEX natural gas prices | 28 | (35) |
| Change in commercial activity | 10 | (19) |
| (Decreased) increased gains on transportation hedges from the narrowing of transportation basis spreads and changes in park and loan hedges | (42) | 27 |
| Change in LOCOM adjustment, net of hedging recoveries | (2) | 16 |
| Decrease in operating margin | (6) | (11) |
| | | |
| Operating expenses | | |
| Increased payroll and other operating costs | 2 | - |
| (Decreased) increased incentive compensation costs | (8) | 4 |
| Decreased depreciation expenses | (1) | (2) |
| (Decrease) increase in operating expenses | (7) | 2 |
| Increased other income | 1 | - |
| EBIT – current year | $ 49 | $ 47 |

The following table indicates the components of wholesale services' operating margin for 2010, 2009 and 2008.

| In millions | 2010 | 2009 | 2008 |
|---|---|---|---|
| Commercial activity | $ 77 | $ 67 | $ 86 |
| Gain on transportation hedges | 1 | 43 | 7 |
| Gain on storage hedges | 29 | 1 | 36 |

| | | | |
|---|---|---|---|
| Gain on park and loan hedges | - | - | 9 |
| Inventory LOCOM, net of hedging recoveries | (2) | - | (16) |
| Operating margin | $ 105 | $ 111 | $ 122 |

For more information on Sequent’s expected operating revenues from its storage inventory in 2011 and discussion of commercial activity, see description of the inventory roll-out schedule in Item 1 “Business.”

Energy Investments

| In millions | 2010 | 2009 |
|---|---|---|
| EBIT – prior year | $ 12 | $ 19 |
| | | |
| Operating margin | | |
| Decreased operating revenues due to the sale of AGL Networks | (10) | - |
| Increased revenues at Golden Triangle Storage | 4 | - |
| Decreased revenues at Jefferson Island | - | (2) |
| Other | (1) | (2) |
| Decrease in operating margin | (7) | (4) |
| | | |
| Operating expenses and other loss | | |
| Decreased costs due to sale of AGL Networks | (5) | - |
| Increased payroll, benefit costs, deprecation and outside services expenses at Golden Triangle Storage | 4 | - |
| (Decreased) increased outside services and other expenses at Jefferson Island | (2) | 1 |
| Other | 2 | 1 |
| (Decrease) increase in operating expenses | (1) | 2 |
| Increased other expenses | 2 | 1 |
| EBIT – current year | $ 4 | $ 12 |

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Liquidity and Capital Resources

Overview The acquisition of natural gas, pipeline capacity, payment of dividends, and working capital requirements are our most significant short-term financing requirements. The need for long-term capital is driven primarily by capital expenditures and maturities of long-term debt. In addition, we anticipate incurring indebtedness in connection with financing the consideration for the proposed Nicor merger.

The liquidity required to fund our working capital, capital expenditures and other cash needs is primarily provided by our operating activities. Our short-term cash requirements not met by cash from operations are primarily satisfied with short-term borrowings under our commercial paper program, which is supported by our Credit Facility. Periodically, we raise funds supporting our long-term cash needs from the issuance of long-term debt or equity securities. We regularly evaluate our funding strategy and profile to ensure that we have sufficient liquidity for our short-term and long-term needs in a cost-effective manner.

Our capital market strategy has continued to focus on maintaining a strong Consolidated Statement of Financial Position, ensuring ample cash resources and daily liquidity, accessing capital markets at favorable times as needed, managing critical business risks and maintaining a balanced capital structure through the appropriate issuance of equity or long-term debt securities.

Our issuance of various securities, including long-term and short-term debt and equity, is subject to customary approval or review by state and federal regulatory bodies including the various public service commissions of the states in which we conduct business, the SEC and the FERC. Furthermore, a substantial portion of our consolidated assets, earnings and cash flows are 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 believe the amounts available to us under our senior notes and Credit Facility, Bridge Facility, Term Loan Facility and through the issuance of debt and equity securities, combined with cash provided by our operating activities, will continue to allow us to meet our needs for working capital, pension contributions, construction expenditures, anticipated debt redemptions, interest payments on debt obligations, dividend payments, common share repurchases, financing requirements for the Nicor merger and other cash needs through the next several years. Nevertheless, our ability to satisfy our working capital requirements and debt service obligations, or fund planned capital expenditures, will substantially depend upon our future operating performance (which will be affected by prevailing economic conditions), and financial, business and other factors, some of which we are unable to control. These factors include, among others regulatory changes, the price of natural gas, the demand for natural gas and operational risks.

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, the proposed merger with Nicor and other factors. See Item 1A, “Risk Factors,” for additional information on items that could impact our liquidity and capital resource requirements.

Cash Flows

The following table provides a summary of our cash flows provided by (used in) operating, investing and financing activities for the last three years.

| In millions | 2010 | 2009 | 2008 |
|---|---|---|---|
| Net cash provided by (used in): | | | |
| Operating activities | $ 526 | $ 592 | $ 227 |
| Investing activities | (442) | (476) | (372) |
| Financing activities | (86) | (106) | 142 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Net increase (decrease) in cash and cash equivalents | | (2) | | 10 | | (3) |
| Cash and cash equivalent at beginning of period | | 26 | | 16 | | 19 |
| Cash and cash equivalent at end of period | $ | 24 | $ | 26 | $ | 16 |

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 derivative financial instrument assets and liabilities, deferred income taxes and changes in the Consolidated Statements of Financial Position for working capital from the beginning to the end of the period.

Year-over-year changes in our operating cash flows are primarily due 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, natural gas storage, the timing of customer collections, payments for natural gas purchases and deferred gas cost recoveries. The increase or decrease in the price of natural gas directly impacts the cost of gas stored in inventory.

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2010 compared to 2009 In 2010, our net cash flow provided from operating activities was $526 million, a decrease of $66 million or 11% from 2009. This decrease was primarily a result of colder weather in the fourth quarter of 2010 as compared to 2009 within most of our service areas. As a result, the use of working capital for our gas receivables increased $134 million due to increased volumes sold to our customers.

We also refunded an additional $38 million to our utility customers for billed commodity costs compared to 2009 as natural gas commodity cost recovery rates charged to customers were reduced as under-recovered amounts were collected in part due to the decline in natural gas prices.

This increased use of operating cash flow was mostly offset by decreased working capital used by Sequent of $128 million for its energy marketing activities, resulting from the timing of payments for gas purchases relative to collections of accounts receivable and an increase in Sequent's daily physical sales.

2009 compared to 2008 In 2009, our net cash flow provided from operating activities was $592 million, an increase of $365 million or 161% from 2008. The primary contributor to the recovery of working capital during 2009 was significantly lower natural gas commodity prices as compared to 2008. During 2008, the cost of natural gas increased significantly during the natural gas storage injection season. This resulted in a higher cost of inventories in 2008 as compared to 2009, and consequently higher customer bills and accounts receivable at the end of 2008. The higher receivable balances and inventory costs were billed to and /or collected from customers during 2009, which resulted in a $173 million increase in cash from the collection of our natural gas receivables and a $103 million increase in cash from our inventory withdrawals.

As a result of the lower natural gas prices during 2009, we used less cash while refilling our natural gas inventories. The lower natural gas prices and associated inventory costs reduced customer bills at the end of 2009, allowing us to reduce our working capital needs. Also contributing to the higher operating cash flows was the return of cash collateral requirements posted during 2008 due to unrealized hedge losses resulting from the dramatic decline in natural gas prices during the second half of 2008 and into 2009. Cash collateral requirements decreased $200 million for our derivative financial instrument activities at Sequent and SouthStar due to the change in hedge values as forward NYMEX curve prices shifted downward in 2009 and as positions settled.

Cash Flow from Investing Activities Our net cash used in investing activities consisted primarily of PP&E expenditures. The majority of our PP&E expenditures are within our distribution operations and energy investment segments.

Our estimated PP&E expenditures for 2011 and our actual PP&E expenditures incurred in 2010, 2009 and 2008 are shown within the following categories and are presented in the table below.

- Base business – new construction and infrastructure improvements at our distribution operations segment
- Regulatory infrastructure programs – Programs that update or expand our distribution systems and liquefied natural gas facilities to improve system reliability and meet operational flexibility and growth. These programs include the pipeline replacement program and STRIDE at Atlanta Gas Light and Elizabethtown Gas' utility infrastructure enhancements program.
- Hampton Roads – Virginia Natural Gas' pipeline project, which connects its northern and southern systems
- Magnolia project – pipelines which diversify our sources of natural gas by connecting our Georgia service territory to the Elba Island LNG terminal
- Natural gas storage – salt-dome cavern expansions at Golden Triangle Storage and Jefferson Island
- Other – primarily includes information technology and building and leasehold improvements

| In millions | 2008 | 2009 | 2010 | 2011 (1) |
|---|---|---|---|---|
| Base business | $ 131 | $ 132 | $ 159 | $ 146 |

| | | | | |
|---|---|---|---|---|
| Regulatory infrastructure programs | 70 | 76 | 186 | 175 |
| Hampton Roads and Magnolia project | 48 | 136 | 3 | - |
| Natural gas storage | 64 | 95 | 114 | 37 |
| Other | 59 | 37 | 48 | 81 |
| Total | $ 372 | $ 476 | $ 510 | $ 439 |

(1) Estimated PP&E expenditures

Our PP&E expenditures were $510 million for the year ended December 31, 2010, compared to $476 million for the same period in 2009. This increase of $34 million or 7% was primarily due to a $19 million increase in expenditures for the construction of the Golden Triangle Storage natural gas storage facility, $26 million in expenditures for Elizabethtown Gas' utility infrastructure enhancements program and $84 million in expenditures for STRIDE and $38 million in other capital projects in distribution operations. This was offset by reduced expenditures of $133 million for the Hampton Roads and Magnolia projects, for which construction was substantially completed in 2009. The higher capital expenditures were further offset by $73 million in proceeds from the disposition of assets.

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In 2009, our PP&E expenditures were $104 million or 28% higher than in 2008. This was primarily due to $43 million expended for the completed Magnolia project, $45 million in increased spending for the completed Hampton Roads pipeline project and an increase in our natural gas storage project expenditures of $31 million as we continued construction of our Golden Triangle Storage facility. This was largely offset by decreased expenditures of $22 million for the other category, primarily on information technology and building and leasehold improvements.

Our estimated expenditures for 2011 include discretionary spending for capital projects principally within the base business, regulatory infrastructure programs and other categories. We continually evaluate whether to proceed with these projects, reviewing them in relation to 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. We will make adjustments to these discretionary expenditures as necessary based upon these factors.

Cash Flow from Financing Activities 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, 2010, our variable-rate debt was $892 million or 33% of our total debt, compared to $762 million or 30% as of December 31, 2009. This increase was principally due to increased commercial paper borrowings. As of December 31, 2010, our commercial paper borrowings were $131 million or 22% higher than the same time last year, primarily a result of higher working capital requirements and increased capital expenditures. For more information on our debt, see Note 7.

Our cash used in financing activities was $86 million in 2010 compared to cash used of $106 million in 2009. The decreased use of cash of $20 million was primarily due to increased commercial paper borrowings of $395 million in 2010 compared to 2009. This was partially offset by our issuance of $300 million of senior notes in August 2009. Additional offsets in 2010 include our purchase of an additional 15% ownership interest in SouthStar for $58 million, an increase in dividends paid on common shares of $6 million, purchase of treasury shares of $7 million and an increased distribution to the noncontrolling interest of $7 million.

Credit Ratings Our borrowing costs and ability to obtain adequate and cost effective financing are directly impacted by our credit ratings as well as the availability of financial markets. In addition, credit ratings are important to counterparties when we engage in certain transactions including OTC derivatives. It is our long-term objective to maintain, or improve, our credit ratings to manage our existing financing cost and enhance our ability to raise additional capital on favorable terms.

Credit ratings and outlooks are opinions subject to ongoing review by the rating agencies and may periodically change. Each rating should be evaluated independently of any other rating. The rating agencies regularly review our performance, prospects and financial condition and reevaluate their ratings of our long-term debt and short-term borrowings, including our corporate ratings.

There is no guarantee 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. A credit rating is not a recommendation to buy, sell or hold securities.

Factors we consider important in assessing our credit ratings include our statements of financial position 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 and have not entered into any agreements that would require us to issue equity based on credit ratings or other trigger events.

The following table summarizes our credit ratings as of December 31, 2010.

| | S&P | Moody's | Fitch |
|---|---|---|---|
| Corporate rating | A- | | A- |
| Commercial paper | A-2 | P-2 | F2 |
| Senior unsecured | BBB+ | Baa1 | A- |
| Ratings outlook | Negative | Stable | Stable |

Subsequent to the announcement of our proposed merger with Nicor, S&P placed our long-term debt ratings and our A- corporate credit ratings on credit watch with negative implications. The primary reason for this change is the increased leverage we will assume to complete the proposed merger and the uncertainties that exist with the proposed merger. S&P's rating for our commercial paper was affirmed A-2. Moody's and Fitch each affirmed stable outlooks for their ratings of our debt obligations based on our sufficient equity as part of the financing for the proposed merger.

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Our credit ratings depend largely on our financial performance, and a downgrade in our current ratings, particularly below investment grade, could adversely affect our borrowing costs and significantly limit our access to the commercial paper market. 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 could decrease.

Merger Financing Agreements In December 2010, we amended our existing Credit Facility to allow for the closing of the proposed merger with Nicor. Additionally, in December 2010, we entered into a $1.05 billion Bridge Facility. The Bridge Facility may be used to partially finance the cash portion of our proposed merger with Nicor and pay related fees and expenses in the event that permanent financing is not available at the time of the closing of the proposed merger.

The Bridge Facility matures 364 days after funds are borrowed and any repaid amounts under the Bridge Facility may not be re-borrowed. The interest rate applicable to the Bridge Facility is the higher of (i) at our option, a floating base rate or a floating Eurodollar rate, in each case, plus an applicable margin ranging from 0.5% to 2.5% based on our credit rating, and the applicable interest rate option, and subject to a 0.25% increase for each 90 day period that elapses after the closing of the Bridge Facility or (ii) the highest interest rate we or any of our subsidiaries are paying on any similar facility. As of December 31, 2010, we had no outstanding borrowings under our Bridge Facility.

We do not currently plan to draw on our Bridge Facility to fund the proposed merger with Nicor, as we anticipate having more permanent financing in place subsequent to receipt of all regulatory approvals.

Default Provisions 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 Credit Facility contains customary events of default, including, but not limited to, the failure to pay any interest or principal when due, the failure to furnish financial statements within the timeframe established by each debt facility, the failure to comply with certain affirmative and negative covenants, cross-defaults to certain other material indebtedness in excess of specified amounts, incorrect or misleading representations or warranties, insolvency or bankruptcy, fundamental change of control, the occurrence of certain Employee Retirement Income Security Act events, judgments in excess of specified amounts and certain impairments to the guarantee.

Our Credit Facility contains certain non-financial covenants that, among other things, restrict liens and encumbrances, loans and investments, acquisitions, dividends and other restricted payments, asset dispositions, mergers and consolidations and other matters customarily restricted in such agreements.

Our Credit Facility also includes a financial covenant that does not permit our ratio, on a consolidated basis, of total debt to total capitalization to exceed 70% (excluding for these purposes, debt incurred to partially refinance the Bridge Facility during the period prior to funding under the Bridge Facility) at the end of any fiscal month. This ratio, as defined within our debt agreements, includes standby letters of credit, performance/surety bonds and the exclusion of other comprehensive income pension adjustments. Adjusting for these items, our ratio, on a consolidated basis, of total debt to total capitalization was 58% at December 31, 2010 and 57% at December 31, 2009.

As of December 31, 2010 and 2009, we were in compliance with all of our existing debt provisions and covenants, both financial and non-financial. Additionally, our Bridge Facility and Term Loan facility each contain the same financial covenant and similar non-financial covenants and default provisions; however, these are not effective until we draw under these facilities.

Our ratio, on a consolidated basis, of total debt to total capitalization is typically greater at the beginning of the Heating Season as we make additional short-term borrowings to fund our natural gas purchases and meet our working capital requirements. We intend to maintain our capitalization ratio in a target range of 50% to 60%. Accomplishing this capital structure objective and maintaining sufficient cash flow are necessary to maintain attractive credit ratings.

The components of our capital structure, as calculated from our Consolidated Statements of Financial Position, as of the dates indicated, are provided in the following table.

| In millions | December 31, 2010 | | | December 31, 2009 | | |
|---|---|---|---|---|---|---|
| Short-term debt | $ 1,033 | 23 | % | $602 | 14 | % |
| Long-term debt | 1,673 | 37 | | 1,974 | 45 | |
| Total debt | 2,706 | 60 | | 2,576 | 59 | |
| Equity | 1,836 | 40 | | 1,819 | 41 | |
| Total capitalization | $ 4,542 | 100 | % | $4,395 | 100 | % |

Short-term Debt Our short-term debt is composed of borrowings and payments under our Credit Facility and commercial paper program, lines of credit and payments of the current portion of our capital leases and our senior notes maturing in less than one year.

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| In millions | | Year-end balance outstanding (1) | | Daily average balance outstanding (2) | | Largest balance outstanding (2) |
|---|---|---|---|---|---|---|
| Commercial paper | $ | 732 | $ | 419 | $ | 760 |
| Senior notes | | 300 | | 300 | | 300 |
| Capital leases | | 1 | | 1 | | 1 |
| Total short-term debt | $ | 1,033 | $ | 720 | $ | 1,061 |

(1) As of December 31, 2010.
(2) For the year ended December 31, 2010.

The largest amounts borrowed on our commercial paper borrowings are important when assessing the intra-period fluctuation of our short-term borrowings and any potential liquidity risk. Our year-end short-term debt outstanding and our largest short-term debt balance outstanding are significantly higher than our average short-term debt outstanding during 2010 due to our seasonal short-term cash requirements.

Such cash requirements generally increase between June and December as we purchase natural gas and pipeline capacity in advance of the Heating Season. The variation of when we pay our suppliers for natural gas purchases and pipeline capacity and when we recover our costs from our customers through their monthly bills can significantly affect our short-term cash requirements. Our short-term debt balances are typically reduced during the Heating Season because a significant portion of our current assets, primarily natural gas inventories, are converted into cash in the Heating Season.

Additionally, increasing natural gas commodity prices can have a significant impact on our commercial paper borrowings. Based on current natural gas prices and our expected purchases during the upcoming injection season, a $1 increase per Mcf in natural gas prices could result in an additional $60 to $70 million of working capital requirements during the peak of the Heating Season based upon our current injection plan. This range is sensitive to the timing of storage injections and withdrawals, collateral requirements and our portfolio position.

In September 2010, we entered into our new Credit Facility. The new Credit Facility matures in September 2013, and replaced our previous $1 billion facility that was due to expire during 2011. The new Credit Facility allows us to borrow up to $1 billion on a revolving basis, and includes an option to increase the Credit Facility to $1.25 billion, subject to the agreement by lenders who wish to participate in such an increase. The new Credit Facility may be used to provide for working capital, finance certain permitted acquisitions, issue up to $250 million in letters of credit and for general corporate purposes including to provide commercial paper backstop, fund capital expenditures, make repurchases of capital stock and repay existing indebtedness.

In December 2010, we amended our Credit Facility in connection with the Nicor merger to, among other things, increase the accordion feature from $250 million to $750 million. As of December 31, 2010 and 2009 we had no outstanding borrowings under our Credit Facility.

In December 2010, we entered into a $300 million Term Loan Facility to help repay the senior notes that matured in January 2011. The Term Loan Facility matures 180 days after the funds are borrowed. The interest rate applicable to the Term Loan Facility is, at our option, a floating base rate or a floating Eurodollar rate, in each case, plus an applicable margin ranging from 0.5% to 2.5% based on our credit rating and interest rate option. As of December 31, 2010, we had no outstanding borrowings under our Term Loan Facility. However, subsequent to year-end, along with $150 million of commercial paper borrowings we borrowed $150 million under the Term Loan Facility to repay the $300 million of senior notes that matured in January 2011. In February 2011, we intend to use commercial paper borrowings to repay the $150 million currently outstanding under the Term Loan Facility.

SouthStar has a $75 million line of credit which is used for its working capital and general corporate needs. Additionally, Sequent has a $5 million line of credit that bears interest at the London interbank offered rate (LIBOR) plus 3.0%. Sequent's line of credit is used solely for the posting of margin deposits for NYMEX transactions and is unconditionally guaranteed by us. As of December 31, 2010 and 2009, we had no outstanding borrowings on either of these lines of credit.

The lenders under our Credit Facility, Bridge Facility, Term Loan Facility and lines of credit are major financial institutions with approximately $2.6 billion of committed balances and all have investment grade credit ratings as of December 31, 2010.Based on current credit market conditions, it is possible that one or more lending commitments could be unavailable to us if the lender defaulted due to lack of funds or insolvency. However, based on our current assessment of our lenders' creditworthiness, we believe the risk of lender default is minimal.

Long-term Debt Our long-term debt matures more than one year from December 31, 2010 and consists of medium-term notes, senior notes, gas facility revenue bonds, and capital leases.

Our long-term cash requirements primarily depend upon the level of capital expenditures, long-term debt maturities and decisions to refinance long-term debt. The following represents our long-term debt activity over the last three years.

Gas Facility Revenue Bonds

In June and September 2008, we refinanced $160 million of our gas facility revenue bonds. There was no change to the maturity dates of these bonds. In October 2010, we completed the remarketing of $160 million of gas facility revenue bonds with rates that reset daily. As part of the remarketing, we entered into new agreements with remarketing agents to resell the bonds to investors. We established new letters of credit to provide credit enhancement to the bonds. The weighted average interest rates on our variable rate bonds during 2010 ranged from 0.23% to 0.36%.

Senior notes

In August 2009, we issued $300 million of 10-year senior notes at an interest rate of 5.25%. The net proceeds from the offering were approximately $297 million. We used the net proceeds from the sale of the senior notes to repay a portion of our short-term debt.

We had $300 million of senior notes that matured in January 2011, which, as of December 31, 2010, were reported as the current portion of long-term debt on our Consolidated Statements of Financial Position. These senior notes were repaid in January 2011 with $150 million of our commercial paper and $150 million borrowed under our Term Loan Facility.

Noncontrolling Interest We recorded cash distributions for SouthStar's dividend distributions to Piedmont of $27 million in 2010, $20 million in 2009 and $30 million in 2008 in our Consolidated Statement of Cash Flows as financing activities.

Dividends on Common Stock Our common stock dividend payments were $133 million in 2010, $127 million in 2009 and $124 million in 2008. The increases were generally the result of annual dividend increases of $0.04 per share for each of the last three years. For information about restrictions on our ability to pay dividends on our common stock, see Note 2 "Significant Accounting Policies and Methods of Application."

Treasury Shares 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 common shares that we will purchase, and we can terminate or limit the program at any time. This program expired in January 2011.

For the year ended December 31, 2010, we purchased approximately 0.2 million shares of our common stock at a weighted average cost of $36.01 per common share and an aggregate cost of $7 million. For the years ended December 31, 2009 and 2008, we did not purchase shares of our common stock. We currently anticipate holding the purchased shares as treasury shares. For more information on our common share repurchases see Item 5 "Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities."

Shelf Registration On August 17, 2010, we filed a shelf registration with the SEC, which expires in 2013. Debt securities and related guarantees issued under the shelf registration 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 Mellon 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 and Term Loan Facility financial covenants related to total debt to total capitalization. The debt securities will be guaranteed by AGL Resources.

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. 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.

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The following table illustrates our expected future contractual obligation payments such as debt and lease agreements, and commitments and contingencies as of December 31, 2010.

| In millions | Total | 2011 | 2012 & 2013 | 2014 & 2015 | 2016 & thereafter |
|---|---|---|---|---|---|
| Recorded contractual obligations: | | | | | |
| Long-term debt | $1,673 | $- | $242 | $200 | $1,231 |
| Short-term debt (1) | 1,033 | 1,033 | - | - | - |
| Pipeline replacement program costs (2) | 228 | 62 | 166 | - | - |
| Environmental remediation liabilities (2) | 143 | 14 | 62 | 53 | 14 |
| Total | $3,077 | $1,109 | $470 | $253 | $1,245 |
| Unrecorded contractual obligations and commitments (3) (9): | | | | | |
| Pipeline charges, storage capacity and gas supply (4) | $1,899 | $523 | $663 | $262 | $451 |
| Interest charges (5) | 897 | 89 | 166 | 144 | 498 |
| Operating leases (6) | 95 | 22 | 30 | 13 | 30 |
| Pension contributions (7) | 30 | 30 | - | - | - |
| Asset management agreements (8) | 15 | 10 | 3 | 2 | - |
| Standby letters of credit, performance / surety bonds (10) | 14 | 12 | 2 | - | - |
| Total | $2,950 | $686 | $864 | $421 | $979 |

(1) Includes current portion of long-term debt of $300 million which matured and was repaid in January 2011.
(2) Includes charges recoverable through rate rider mechanisms.
(3) In accordance with GAAP, these items are not reflected in our Consolidated Statements of Financial Position.
(4) Includes charges recoverable through a natural gas cost recovery mechanism or alternatively billed to Marketers and demand charges associated with Sequent. The gas supply amount includes SouthStar gas commodity purchase commitments of 14 Bcf at floating gas prices calculated using forward natural gas prices as of December 31, 2010, and is valued at $63 million. As we do for other subsidiaries, we provide guarantees to certain gas suppliers for SouthStar in support of payment obligations.
(5) Floating rate debt is based on the interest rate as of December 31, 2010 and the maturity date of the underlying debt instrument. As of December 31, 2010, we have $40 million of accrued interest on our Consolidated Statements of Financial Position that will be paid in 2011.
(6) 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 authoritative guidance related to leases. However, this lease 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.
(7) Based on the current funding status of the plans, we would be required to make a minimum contribution to our pension plans of approximately $30 million in 2011. We may make additional contributions in 2011.
(8) Represent fixed-fee minimum payments for Sequent's affiliated asset management agreements.
(9) The Merger Agreement with Nicor contains termination rights for both us and Nicor and provides that, if we terminate the agreement under specified circumstances, we may be required to pay a termination fee of $67 million. In addition, if we terminate the agreement due to a failure to obtain the necessary financing for the transaction, we may also be required to pay Nicor $115 million.
(10) We provide guarantees to certain gas suppliers of SouthStar in support of payment obligations.

Standby letters of credit and performance / 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. Generally, our funding policy is to contribute annually an amount that will at least equal the minimum amount required to comply with the Pension Protection Act. Additionally, we calculate any required pension contributions using the traditional unit credit cost method. However, additional voluntary contributions are made from time to time as considered necessary. Contributions are intended to provide not only for benefits attributed to service to date, but also for those expected to be earned in the future. The contributions represent the portion of the postretirement costs we are responsible for under the terms of our plan and minimum funding required by state regulatory commissions.

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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 $9 million as of December 31, 2010 and $10 million as of December 31, 2009. In addition, we recorded a regulatory liability of $6 million as of December 31, 2010 and $5 million as of December 31, 2009 for our expected expenses under the AGL Postretirement Plan. See Note 5 “Employee Benefit Plans,” for additional information about our pension and postretirement plans

In 2010, we contributed $31 million to our qualified pension plans. In 2009, we contributed $24 million to our qualified pension plans. Based on the current funding status of the plans, we would be required to make a minimum contribution to the plans of approximately $30 million in 2011. We are planning to make additional contributions in 2011 up to $31 million, for a total of up to $61 million, in order to preserve the current level of benefits under the plans and in accordance with the funding requirements of the Pension Protection Act.

Critical Accounting Policies and Estimates

The preparation of our financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts in our consolidated financial statements and accompanying notes. Those judgments and estimates have a significant effect on our financial statements because they result primarily from the need to make estimates about the effects of matters that are inherently uncertain. Actual results could differ from those estimates. We frequently re-evaluate our judgments and estimates that are based upon historical experience and various other assumptions that we believe to be reasonable under the circumstances.

We believe that of our significant accounting policies, described in Note 2 of the Notes to Consolidated Financial Statements, the following represents those that may involve a higher degree of uncertainty, judgment and complexity; these include Regulatory Infrastructure Program Liabilities, Environmental Remediation Liabilities, Derivatives and Hedging Activities, Contingencies, Pension and Other Postretirement Plans and Income Taxes.

Regulatory Infrastructure Program Liabilities

We record regulatory assets and liabilities in our Consolidated Statements of Financial Position in accordance with authoritative guidance related to regulated entities. We record regulatory assets for costs that have been deferred for which future recovery is probable through either rate riders or base rates specifically authorized by a state regulatory commission. We record regulatory liabilities when it is probable that revenues will be reduced for amounts that will be credited to customers through the rate making process.

By order of the Georgia Commission, our wholly-owned subsidiary, Atlanta Gas Light began a pipeline replacement program to replace all bare steel and cast iron pipe in its system by December 2013. The order 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 (i) the costs incurred to date that have not yet been recovered through rate riders, and (ii) the future expected costs to be recovered through rate riders.

The determination of future expected costs associated with our pipeline replacement program liabilities involves judgment. Factors that must be considered in estimating the future expected costs are:

- projected capital expenditure spending, including labor and material costs
- the remaining pipeline footage to be replaced for remainder of the program
- changes in the regulatory environment or our completive position

- passage of new legislation
- changes in accounting guidance

To the extent that circumstances associated with regulatory balances change, the regulatory balances are adjusted accordingly.

We recorded a long-term liability of $166 million as of December 31, 2010 and $155 million as of December 31, 2009, which represented engineering estimates for remaining capital expenditure costs in the pipeline replacement program. As of December 31, 2010, we had recorded a current liability of $62 million, representing expected pipeline replacement program expenditures for the next 12 months. We report these estimates on an undiscounted basis. If Atlanta Gas Light's pipeline replacement program expenditures, subject to future recovery, were $10 million higher or lower its incremental expected annual revenues would have changed by approximately $1 million. Details of our regulatory assets and liabilities are discussed in Note 2.

Environmental Remediation Liabilities

We are subject to legislation and regulation by federal, state and local authorities with respect to environmental matters. Additionally, we owned and operated a number of MGP sites at which hazardous substances may be present. In accordance with GAAP, we have established reserves for environmental remediation obligations when it is probable that a liability exists and the amount or range of amounts can be reasonably estimated. We historically reported estimates of future environmental remediation costs based on probabilistic models of potential costs. We presently report estimates of future remediation costs on an undiscounted basis. These estimates contain various engineering uncertainties, and we continuously attempt to refine these estimates.

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In Georgia and Florida, we have confirmed 14 former MGP sites where Atlanta Gas Light owned or operated all or part of these sites. Atlanta Gas Light's environmental remediation liability is included in its corresponding regulatory asset. Our recovery of these environmental remediation costs is subject to review by the Georgia Commission, which may seek to disallow the recovery of some expenses.

We have identified 6 former operating sites in New Jersey, where Elizabethtown Gas is currently conducting remediation activities with oversight from the New Jersey Department of Environmental Protection. The New Jersey BPU has authorized Elizabethtown Gas to recover prudently incurred remediation costs for the New Jersey properties through its remediation adjustment clause.

We also own remediation sites in other states. One site, in Elizabeth City, North Carolina, is subject to an order by the North Carolina Department of Environment and Natural Resources. There is one other site in North Carolina where investigation and remediation is possible. We do not believe costs associated with this site can be reasonably estimated. There are no cost recovery mechanisms for the environmental remediation sites in North Carolina.

We cannot perform precise engineering soil and groundwater clean up estimates for certain of our former MGP sites. As we continue to conduct the actual remediation and enter into cleanup contracts, we are increasingly able to provide conventional engineering estimates of the likely costs of many elements of the remediation program. The following table provides more information on our former operating sites:

| In millions | Cost estimate range | Amount recorded | Expected costs over next twelve months |
|---|---|---|---|
| Georgia and Florida | $ 57 - $105 | $ 57 | $ 3 |
| New Jersey | 75 - 138 | 75 | 10 |
| North Carolina | 11 - 16 | 11 | 1 |
| Total | $ 143 - $259 | $ 143 | $ 14 |

In accordance with GAAP we have recorded the lower end of the range. Beyond 2012, these costs cannot be estimated and considerable variability remains in available estimates. Details of our environmental remediation costs are discussed in Note 2 and Note 10.

Derivatives and Hedging Activities

The authoritative guidance related to derivatives and hedging requires that every derivative financial instrument (including certain derivative instruments embedded in other contracts) be recorded in the statements of financial position 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 and is subject to traditional accrual accounting. We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs of the valuation technique.

The guidance requires that changes in the derivative's fair value are recognized concurrently in earnings unless specific hedge accounting criteria are met. If the derivatives meet those criteria, the guidance 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 the hedged transaction occurs in the case of a cash flow hedge. Additionally, the guidance 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.

We use derivative financial instruments primarily to reduce the impact to our results of operations due to the risk of changes in the price of natural gas. The fair value of natural gas derivative financial instruments we use to manage exposures arising from changing natural gas prices 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.

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Additionally, as required by the authoritative guidance, we are required to classify our derivative financial assets and liabilities based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The determination of the fair value of our derivative instruments incorporates various factors required under the guidance. These factors include:

- the credit worthiness of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit)
- events specific to a given counterparty
- the impact of our nonperformance risk on our liabilities.

We have recorded derivative financial instrument assets of $228 million at December 31, 2010 and $238 million at December 31, 2009. Additionally, we have recorded derivative financial liabilities of $48 million at December 31, 2010 and $62 million at December 31, 2009. In 2010, we recorded $46 million of losses and in 2009 we recorded $15 million of losses on our Consolidated Statements of Income.

If there is a significant change in the underlying market prices or pricing assumptions we use in pricing our derivative assets or liabilities, we may experience a significant impact on our financial position, result of operations and cash flows. Our derivative and hedging activities are described in further detail in Note 2 and Item 1, “Business”.

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 authoritative guidance related to contingencies. 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. Changes in the estimates related to contingencies could have a negative impact on our consolidated results of operations, cash flows or financial position. Our contingencies are further discussed in Note 10.

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. We annually review the estimates and assumptions underlying our pension and other postretirement plan costs and liabilities and update when appropriate.

The critical actuarial assumptions used to develop the required estimates for our pension and postretirement plans include the following key factors:

- assumed discount rates
- expected return on plan assets
- the market value of plan assets
- assumed mortality table
- assumed rates of retirement.

The discount rate is utilized in calculating the actuarial present value of our pension and postretirement obligations and net pension and postretirement costs. When establishing our discount rate, with the assistance of our actuaries, we consider certain market indices, including Moody's Corporate AA long-term bond rate, the Citigroup Pension Liability rate, other high-grade bond indices and a single equivalent discount rate derived utilizing the forecasted future cash flows in each year to the appropriate spot rates based on high quality (AA or better) corporate bonds.

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.

Equity market performance and corporate bond rates have a significant effect on our reported results. For our largest pension plan, market performance also effects 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.

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In addition, 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 projected benefit obligation (PBO) or the MRVPA for our largest pension plan. If necessary, the excess is amortized over the average remaining service period of active employees.

During 2010, we recorded net periodic benefit costs of $17 million related to our defined pension and postretirement benefit costs. We estimate that in 2011, we will record net periodic pension and other postretirement benefit costs in the range of $19 million to $21 million, a $2 million to $4 million increase compared to 2010. In determining our estimated expenses for 2011, our actuarial consultant assumed an 8.75% expected return on plan assets and a discount rate of 5.40% for the AGL Retirement Plan and 5.20% for the NUI Retirement Plan and for our postretirement plan.

The actuarial assumptions we use may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal and retirement rates, and longer or shorter life spans of participants. The following table illustrates the effect of changing the critical actuarial assumptions for our pension and postretirement plans while holding all other assumptions constant.

| | | In millions | |
|---|---|---|---|
| Actuarial assumptions | Percentage-point change in assumption | Increase (decrease) in APBO | Increase (decrease) in cost |
| Expected long-term return on plan assets | +/- 1 % | $ - / - | $ (4) / 4 |
| Discount rate | +/- 1 % | (80) / 90 | (7) / 7 |

See Note 5 for additional information on our pension and postretirement plans.

Income Taxes

We account for income taxes in accordance with the authoritative guidance related to income taxes, which requires 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. The guidance 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.

This liability is estimated based on the expected future tax consequences of items recognized in the financial statements. Additionally, during the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. As a result, we recognize tax liabilities based on estimates of whether additional taxes and interest will be due. 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. In addition, we operate within multiple tax 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.

We had a $3 million valuation allowance on $109 million of deferred tax assets as of December 31, 2010, reflecting the expectation that most of these assets will be realized. Our net long-term deferred tax liability totaled $768 million at December 31, 2010. See Note 11 for additional information on our taxes.

Accounting Developments

In January 2010, the FASB issued authoritative guidance to improve fair value measurement disclosures. The guidance requires us to separately disclose significant transfers of amounts between Levels 1 and 2 and the reasons for the transfers. In addition, the reconciliation of fair value measurements using significant unobservable inputs (Level 3) should separately present transfers in/out of Level 3 as well as purchases, sales, issuances and settlements. We are required to present fair value measurements for each class of assets and liabilities and to disclose our valuation techniques and inputs used to measure fair value. The amended guidance became effective for us on January 1, 2010, with the exception of the presentation of Level 3 fair value measurements, which will be effective for us on January 1, 2011. The adoption of this guidance did not have a material impact on our consolidated financial statements. For more information on our fair value measurements, see Note 3.

In December 2010, the FASB provided additional guidance for performing Step 1 of the test for goodwill impairment when an entity has reporting units with zero or negative carrying values. Under the new guidance, Step 2 of the goodwill impairment test must be performed when adverse qualitative factors indicate that goodwill is more likely than not impaired. Although the guidance will be effective for us on January 1, 2011, our goodwill impairment analysis for the years ended December 31, 2010 and 2009 indicates that the fair values of our reporting units substantially exceed their carrying values, and we did not take a goodwill impairment charge in the current year nor do we expect to take a charge in future years. The amended guidance is not expected to have a material impact on our consolidated financial statements.

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In December 2010, the FASB issued clarification of the accounting guidance around disclosure of pro forma information for business combinations that occur in the current reporting period. The guidance requires us to present pro forma information in our comparative financial statements as if the acquisition date for any business combinations taking place in the current reporting period had occurred at the beginning of the prior year reporting period. We will adopt this guidance effective January 1, 2011, and include any required pro forma information for our proposed merger with Nicor, which is expected to be completed in the second half of 2011.

## ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to risks associated with natural gas prices, interest rates and credit. Natural gas 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 natural gas 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.

### Natural Gas Price Risk

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

SouthStar routinely utilizes various types of derivative financial instruments to mitigate certain natural gas price and weather risk inherent in the natural gas industry. These instruments include a variety of exchange-traded and OTC energy contracts, such as forward contracts, futures contracts, options contracts and swap agreements. This includes the active management of storage positions through a variety of hedging transactions for the purpose of managing exposures arising from changing natural gas prices. SouthStar uses these hedging instruments to lock in economic margins (as spreads between wholesale and retail natural gas prices widen between periods) and thereby minimize its exposure to declining operating margins.

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

Energy Investments Golden Triangle Storage uses derivative financial instruments to reduce its exposure to the risk of changes in the price of natural gas that will be purchased in future periods for pad gas and additional volumes of gas used to de-water the cavern (de-water gas) during the construction of storage caverns. Pad gas includes volumes of non-working natural gas used to maintain the operational integrity of the caverns. De-water gas is used to remove water from the cavern in anticipation of commercial service and will be sold after completion of de-watering. We also use derivative financial instruments for asset optimization purposes.

Consolidated The following tables include the fair values and average values of our consolidated derivative financial instruments as of the dates indicated. We base the average values on monthly averages for the 12 months ended December 31, 2010 and 2009.

| In millions | Derivative financial instruments average fair values at December 31, 2010 (1) | 2009 (1) |
|---|---|---|
| Asset | $ 226 | $ 194 |
| Liability | 70 | 97 |

(1) Excludes cash collateral amounts.

| In millions | Derivative financial instruments fair values netted with cash collateral at December 31, 2010 | 2009 |
|---|---|---|
| Asset | $ 228 | $ 240 |
| Liability | 48 | 62 |

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The following tables illustrate the change in the net fair value of our derivative financial instruments during the twelve months ended December 31, 2010, 2009 and 2008, and provide details of the net fair value of contracts outstanding as of December 31, 2010, 2009 and 2008.

| In millions | 2010 | 2009 | 2008 |
|---|---|---|---|
| Net fair value of derivative financial instruments outstanding at beginning of period | $ 121 | $ 65 | $ 68 |
| Derivative financial instruments realized or otherwise settled during period | (117 ) | (54 ) | (60 ) |
| Net fair value of derivative financial instruments acquired during period | - | 50 | - |
| Change in net fair value of derivative financial instruments | 71 | 60 | 57 |
| Net fair value of derivative financial instruments outstanding at end of period | 75 | 121 | 65 |
| Netting of cash collateral | 105 | 57 | 129 |
| Cash collateral and net fair value of derivative financial instruments outstanding at end of period (1) | $ 180 | $ 178 | $ 194 |

(1) Net fair value of derivative financial instruments outstanding includes less than $1 million premium and associated intrinsic value at December 31, 2010, $2 million at December 31, 2009 and $4 million at December 31, 2008 associated with weather derivatives.

The sources of our net fair value at December 31, 2010, are as follows.

| In millions | Prices actively quoted (Level 1) (1) | Significant other observable inputs (Level 2) (2) |
|---|---|---|
| Mature through 2011 | $ (32 ) | $ 82 |
| Mature 2012 - 2013 | (17 ) | 31 |
| Mature 2014 - 2016 | - | 11 |
| Total derivative financial instruments (3) | $ (49 ) | $ 124 |

(1) Valued using NYMEX futures prices.

(2) Valued using basis transactions that represent the cost to transport natural gas 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.

(3) Excludes cash collateral amounts.

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

We actively monitor open commodity positions and the resulting VaR. We also continue to maintain a relatively matched book, where our total buy volume is close to our sell volume, with minimal open natural gas price risk. Based on a 95% confidence interval and employing a 1-day holding period, SouthStar's portfolio of positions for the 12 months ended December 31, 2010, 2009 and 2008 were less than $0.1 million and Sequent had the following VaRs.

| In millions | 2010 | 2009 | 2008 |
|---|---|---|---|
| Period end | $ 1.6 | $ 2.4 | $ 2.5 |
| 12-month average | 1.3 | 1.8 | 1.8 |
| High | 3.0 | 3.3 | 3.1 |
| Low | 0.7 | 0.7 | 0.8 |

Interest Rate Risk

Interest rate fluctuations expose our variable-rate debt to changes in interest expense and cash flows. Our policy is to manage interest expense using a combination of fixed-rate and variable-rate debt. Based on $892 million of variable-rate debt, which includes $732 million of our variable-rate short-term debt and $160 million of variable-rate gas facility revenue bonds outstanding at December 31, 2010, a 100 basis point change in market interest rates from 0.4% to 1.4% would have resulted in an increase in pretax interest expense of $9 million on an annualized basis.

Credit Risk

Distribution Operations Atlanta Gas Light has a concentration of credit risk as it bills eleven certificated and active 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 2010, the four largest Marketers based on customer count, which includes SouthStar, accounted for approximately 31% of our consolidated operating margin and 43% 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.

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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 an investment grade rating, which includes 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 have investment grade ratings.

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, 2010, excluding $61 million of customer deposits, Sequent's top 20 counterparties represented approximately 56% of the total counterparty exposure of $598 million, derived by adding together the top 20 counterparties' exposures, exclusive of customer deposits, and dividing by the total of Sequent's counterparties' exposures.

As of December 31, 2010, Sequent's counterparties, or the counterparties' guarantors, had a weighted average S&P equivalent credit rating of BBB+, 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 is assigned an internal ratio, which is multiplied by their credit exposure and summed for all counterparties. The sum is divided by the aggregate total counterparties' exposures, and this numeric value is then converted to an S&P equivalent. There were no credit defaults with Sequent's counterparties. The following table shows Sequent's third-party natural gas contracts receivable and payable positions.

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| In millions | As of Dec. 31, Gross receivables 2010 | 2009 |
|---|---|---|
| Netting agreements in place and counterparty is: | | |
| Investment grade | $ 515 | $ 483 |
| Non-investment grade | 11 | 12 |
| No external rating | 260 | 106 |
| No netting agreements in place and counterparty is: | | |
| Investment grade | 2 | 14 |
| Amount recorded on statements of financial position | $ 788 | $ 615 |

| In millions | As of Dec. 31, Gross payables 2010 | 2009 |
|---|---|---|
| Netting agreements in place and counterparty is: | | |
| Investment grade | $ 341 | $ 277 |
| Non-investment grade | 40 | 34 |
| No external rating | 363 | 207 |
| No netting agreements in place and counterparty is: | | |
| Investment grade | - | 6 |
| Amount recorded on statements of financial position | $ 744 | $ 524 |

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. If such collateral were not posted, Sequent's ability to continue transacting business with these counterparties would be impaired. If our credit ratings had been downgraded to non-investment grade status, the required amounts to satisfy potential collateral demands under such agreements between Sequent and its counterparties would have totaled $39 million at December 31, 2010, which would not have a material impact to our consolidated results of operations, cash flows or financial condition.

Glossary of Key Terms

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 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, 2010, 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.

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

PricewaterhouseCoopers LLP
Atlanta, Georgia
February 9, 2011

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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).

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.

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, 2010, 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.

The effectiveness of our internal control over financial reporting has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report appearing herein.

February 9, 2011

/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

Glossary of Key Terms

AGL Resources Inc.
Consolidated Statements of Financial Position - Assets

| In millions | As of December 31, 2010 | 2009 |
|---|---|---|
| Current assets | | |
| Cash and cash equivalents (Note 2) | $ 24 | $ 26 |
| Receivables (Note 2) | | |
| Energy marketing receivables | 788 | 615 |
| Gas | 204 | 178 |
| Unbilled revenues | 173 | 155 |
| Other | 13 | 29 |
| Less allowance for uncollectible accounts | 16 | 14 |
| Total receivables | 1,162 | 963 |
| Inventories | | |
| Natural gas stored underground | 615 | 649 |
| Other | 24 | 23 |
| Total inventories (Note 2) | 639 | 672 |
| Derivative financial instruments – current portion (Note 2, Note 3 and Note 4) | 182 | 188 |
| Recoverable regulatory infrastructure program costs – current portion (Note 2) | 48 | 43 |
| Recoverable environmental remediation costs – current portion (Note 2 and Note 10) | 7 | 11 |
| Other current assets | 100 | 97 |
| Total current assets | 2,162 | 2,000 |
| Long-term assets and other deferred debits | | |
| Property, plant and equipment | 6,266 | 5,939 |
| Less accumulated depreciation | 1,861 | 1,793 |
| Property, plant and equipment – net (Note 2) | 4,405 | 4,146 |
| Goodwill (Note 2) | 418 | 418 |
| Recoverable regulatory infrastructure program costs (Note 2) | 244 | 223 |
| Recoverable environmental remediation costs (Note 2 and Note 10) | 164 | 161 |
| Derivative financial instruments (Note 2, Note 3 and Note 4) | 46 | 52 |
| Other | 79 | 74 |
| Total long-term assets and other deferred debits | 5,356 | 5,074 |
| Total assets | $ 7,518 | $ 7,074 |

See Notes to Consolidated Financial Statements.

AGL Resources Inc.
Consolidated Statements of Financial Position - Liabilities and Equity

| In millions, except share amounts | As of December 31, 2010 | 2009 |
|---|---|---|
| Current liabilities | | |
| Energy marketing trade payable | $744 | $524 |
| Short-term debt (Note 3 and Note 7) | 732 | 602 |
| Current portion of long-term debt (Note 7) | 300 | - |
| Accounts payable – trade | 184 | 196 |
| Accrued regulatory infrastructure program costs – current portion (Note 2) | 62 | 55 |
| Customer deposits | 52 | 41 |
| Accrued wages and salaries | 51 | 56 |
| Accrued taxes | 48 | 35 |
| Derivative financial instruments – current portion (Note 2, Note 3 and Note 4) | 44 | 52 |
| Accrued interest (Note 10) | 40 | 41 |
| Deferred natural gas costs (Note 2) | 19 | 30 |
| Accrued environmental remediation liabilities – current portion (Note 2 and Note 10) | 14 | 25 |
| Other current liabilities | 138 | 115 |
| Total current liabilities | 2,428 | 1,772 |
| Long-term liabilities and other deferred credits | | |
| Long-term debt (Note 3 and Note 7) | 1,673 | 1,974 |
| Accumulated deferred income taxes (Note 2 and Note 11) | 768 | 695 |
| Accrued pension obligations (Note 3 and Note 5) | 186 | 159 |
| Accumulated removal costs (Note 2) | 182 | 183 |
| Accrued regulatory infrastructure program costs (Note 2) | 166 | 155 |
| Accrued environmental remediation liabilities (Note 2 and Note 10) | 129 | 119 |
| Accrued postretirement benefit costs (Note 3 and Note 5) | 36 | 38 |
| Derivative financial instruments (Note 2, Note 3 and Note 4) | 4 | 10 |
| Other long-term liabilities and other deferred credits | 110 | 150 |
| Total long-term liabilities and other deferred credits | 3,254 | 3,483 |
| Total liabilities and other deferred credits | 5,682 | 5,255 |
| Commitments and contingencies (see Note 10) | | |
| Equity | | |
| AGL Resources Inc. common shareholders' equity, $5 par value; 750 million shares authorized | 1,813 | 1,780 |
| Noncontrolling interest (Note 9) | 23 | 39 |
| Total equity | 1,836 | 1,819 |
| Total liabilities and equity | $7,518 | $7,074 |

See Notes to Consolidated Financial Statements.

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AGL Resources Inc.
Consolidated Statements of Income

| In millions, except per share amounts | Years ended December 31, 2010 | 2009 | 2008 |
|---|---|---|---|
| Operating revenues (Note 2) | $ 2,373 | $ 2,317 | $ 2,800 |
| Operating expenses | | | |
| Cost of gas (Note 2) | 1,164 | 1,142 | 1,654 |
| Operation and maintenance | 503 | 497 | 472 |
| Depreciation and amortization (Note 2) | 160 | 158 | 152 |
| Taxes other than income taxes | 46 | 44 | 44 |
| Total operating expenses | 1,873 | 1,841 | 2,322 |
| Operating income | 500 | 476 | 478 |
| Other (expense) income | (1) | 9 | 6 |
| Interest expenses, net | (109) | (101) | (115) |
| Earnings before income taxes | 390 | 384 | 369 |
| Income tax expenses (Note 11) | 140 | 135 | 132 |
| Net income | 250 | 249 | 237 |
| Less net income attributable to the noncontrolling interest (Note 9) | 16 | 27 | 20 |
| Net income attributable to AGL Resources Inc. | $ 234 | $ 222 | $ 217 |
| Per common share data (Note 2) | | | |
| Basic earnings per common share attributable to AGL Resources Inc. common shareholders | $ 3.02 | $ 2.89 | $ 2.85 |
| Diluted earnings per common share attributable to AGL Resources Inc. common shareholders | $ 3.00 | $ 2.88 | $ 2.84 |
| Cash dividends declared per common share | $ 1.76 | $ 1.72 | $ 1.68 |
| Weighted average number of common shares outstanding (Note 2) | | | |
| Basic | 77.4 | 76.8 | 76.3 |
| Diluted | 77.8 | 77.1 | 76.6 |

See Notes to Consolidated Financial Statements.

Glossary of Key Terms

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AGL Resources Inc.
Consolidated Statements of Equity

| | AGL Resources Inc. Shareholders | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| In millions, except per share amounts | Common stock | | Premium on common stock | Earnings reinvested | Accumulated other comprehensive loss | Treasury shares | Noncontrolling interest | Total |
| | Shares | Amount | | | | | | |
| As of December 31, 2007 | 76.4 | $390 | $667 | $680 | $(13) | $(63) | $47 | $1,708 |
| Net income | - | - | - | 217 | - | - | 20 | 237 |
| Other comprehensive loss (Note 8) | - | - | - | - | (121) | - | (5) | (126) |
| Dividends on common stock ($1.68 per share) | - | - | - | (128) | - | 4 | - | (124) |
| Distributions to noncontrolling interests (Note 9) | - | - | - | - | - | - | (30) | (30) |
| Issuance of treasury shares (Note 8) | 0.5 | - | (1) | (6) | - | 16 | - | 9 |
| Stock-based compensation expense (net of tax) (Note 6) | - | - | 10 | - | - | - | - | 10 |
| As of December 31, 2008 | 76.9 | 390 | 676 | 763 | (134) | (43) | 32 | 1,684 |
| Net income | - | - | - | 222 | - | - | 27 | 249 |
| Other comprehensive income (Note 8) | - | - | - | - | 18 | - | - | 18 |
| Dividends on common stock ($1.72 per share) | - | - | - | (132) | - | 5 | - | (127) |
| Distributions to noncontrolling interests (Note 9) | - | - | - | - | - | - | (20) | (20) |
| Issuance of treasury shares (Note 8) | 0.6 | - | (4) | (5) | - | 17 | - | 8 |
| Stock-based compensation expense (net of tax) (Note 6) | - | - | 7 | - | - | - | - | 7 |
| As of December 31, 2009 | 77.5 | 390 | 679 | 848 | (116) | (21) | 39 | 1,819 |
| Net income | - | - | - | 234 | - | - | 16 | 250 |
| Other comprehensive (loss) income (Note 8) | - | - | - | - | (33) | - | 1 | (32) |
| | - | - | - | (136) | - | 3 | - | (133) |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Dividends on common stock ($1.76 per share) | | | | | | | | |
| Purchase of additional 15% ownership interest in SouthStar (Note 9) | - | - | (51) | - | (1) | - | (6) | (58) |
| Distributions to noncontrolling interests (Note 9) | - | - | - | - | - | - | (27) | (27) |
| Purchase of treasury shares (Note 8) | (0.2) | - | - | - | - | (7) | - | (7) |
| Issuance of treasury shares (Note 8) | 0.7 | 1 | (5) | (3) | - | 22 | - | 15 |
| Stock-based compensation expense (net of tax) (Note 6) | - | - | 8 | - | - | 1 | - | 9 |
| As of December 31, 2010 | 78.0 | $391 | $631 | $943 | $(150) | $(2) | $23 | $1,836 |

See Notes to Consolidated Financial Statements.

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AGL RESOURCES INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

| | Years ended December 31, | | |
|---|---|---|---|
| In millions | 2010 | 2009 | 2008 |
| Comprehensive income attributable to AGL Resources Inc. (net of tax) | | | |
| Net income attributable to AGL Resources Inc. | $ 234 | $ 222 | $ 217 |
| (Loss) gain resulting from unfunded pension and postretirement obligation during the period (Note 5) | (28 ) | 17 | (111 ) |
| Cash flow hedges (Note 4): | | | |
| Derivative financial instruments unrealized losses arising during the period | (14 ) | (12 ) | (4 ) |
| Reclassification of derivative financial instruments realized losses (gains) included in net income | 9 | 13 | (6 ) |
| Other comprehensive (loss) income | (33 ) | 18 | (121 ) |
| Comprehensive income (Note 8) | $ 201 | $ 240 | $ 96 |
| | | | |
| Comprehensive income (loss) attributable to noncontrolling interest (net of tax) | | | |
| Net income attributable to noncontrolling interest (Note 9) | $ 16 | $ 27 | $ 20 |
| Cash flow hedges (Note 4): | | | |
| Derivative financial instruments unrealized losses arising during the period | (1 ) | (7 ) | (1 ) |
| Reclassification of derivative financial instruments realized losses (gains) included in net income | 2 | 7 | (4 ) |
| Other comprehensive income (loss) | 1 | - | (5 ) |
| Comprehensive income (Note 8) | $ 17 | $ 27 | $ 15 |
| | | | |
| Total comprehensive income (net of tax) | | | |
| Net income | $ 250 | $ 249 | $ 237 |
| (Loss) gain resulting from unfunded pension and postretirement obligation during the period | (28 ) | 17 | (111 ) |
| Cash flow hedges (Note 4): | | | |
| Derivative financial instruments unrealized losses arising during the period | (15 ) | (19 ) | (5 ) |
| Reclassification of derivative financial instruments realized losses (gains) included in net income | 11 | 20 | (10 ) |
| Other comprehensive (loss) income | (32 ) | 18 | (126 ) |
| Comprehensive income (Note 8) | $ 218 | $ 267 | $ 111 |

See Notes to Consolidated Financial Statements.

Glossary of Key Terms

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AGL Resources Inc.
Consolidated Statements of Cash Flows

| In millions | Years ended December 31, 2010 | 2009 | 2008 |
|---|---|---|---|
| Cash flows from operating activities | | | |
| Net income | $250 | $249 | $237 |
| Adjustments to reconcile net income to net cash flow provided by operating activities | | | |
| Depreciation and amortization (Note 2) | 160 | 158 | 152 |
| Deferred income taxes (Note 11) | 92 | 105 | 89 |
| Change in derivative financial instrument assets and liabilities (Note 3 and Note 4) | (2) | 11 | (129) |
| Changes in certain assets and liabilities | | | |
| Energy marketing receivables and energy marketing trade payables, net (Note 2) | 47 | (81) | 10 |
| Inventories (Note 2) | 33 | (9) | (112) |
| Accrued expenses | 7 | 19 | 26 |
| Gas and trade payables | (12) | 1 | 29 |
| Deferred natural gas costs (Note 2) | (14) | 24 | 1 |
| Gas, unbilled and other receivables (Note 2) | (26) | 108 | (65) |
| Other – net | (9) | 7 | (11) |
| Net cash flow provided by operating activities | 526 | 592 | 227 |
| Cash flows from investing activities | | | |
| Expenditures for property, plant and equipment (Note 2) | (510) | (476) | (372) |
| Proceeds from the disposition of assets | 73 | - | - |
| Other | (5) | - | - |
| Net cash flow used in investing activities | (442) | (476) | (372) |
| Cash flows from financing activities | | | |
| Net payments and borrowings of short-term debt | 131 | (264) | 286 |
| Issuance of treasury shares (Note 8) | 15 | 8 | 9 |
| Issuances of senior notes (Note 7) | - | 297 | - |
| Issuances of variable rate gas facility revenue bonds (Note 7) | 160 | - | 160 |
| Payments of gas facility revenue bonds (Note 7) | (160) | - | (160) |
| Purchase of treasury shares (Note 8) | (7) | - | - |
| Distribution to noncontrolling interest (Note 9) | (27) | (20) | (30) |
| Purchase 15% ownership in SouthStar from Piedmont (Note 9) | (58) | - | - |
| Dividends paid on common shares (Note 8) | (133) | (127) | (124) |
| Other | (7) | - | 1 |
| Net cash flow (used in) provided by financing activities | (86) | (106) | 142 |
| Net (decrease) increase in cash and cash equivalents | (2) | 10 | (3) |
| Cash and cash equivalents at beginning of period | 26 | 16 | 19 |
| Cash and cash equivalents at end of period | $24 | $26 | $16 |
| Cash paid during the period for | | | |
| Interest | $107 | $93 | $115 |
| Income taxes | 58 | 50 | 27 |

See Notes to Consolidated Financial Statements.

Glossary of Key Terms

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Notes to Consolidated Financial Statements

Note 1 – Organization and Basis of Presentation

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.

Basis of Presentation

Our consolidated financial statements as of and for the period ended December 31, 2010 are prepared in accordance with GAAP and under the rules of the SEC. Our consolidated financial statements include our accounts, the accounts of our majority-owned and controlled subsidiaries and the accounts of our variable interest entity 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. The reclassifications and revisions had no material impact on our prior period balances.

Note 2 – Significant Accounting Policies and Methods of Application

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 and other factors. 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 our customers’ accounts once we deem them to be uncollectible.

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 eleven 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, billings, 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 no less than two times a Marketer’s highest month’s estimated bill from Atlanta Gas Light.

Inventories

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

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 WACOG 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 price. Consequently, as a result of declining natural gas prices, Sequent recorded LOCOM adjustments against cost of gas, to reduce the value of its inventories to market value, of $8 million in 2010, $8 million in 2009 and $40 million in 2008. SouthStar was not required to make LOCOM adjustments in 2010, but recorded LOCOM adjustments of $6 million in 2009 and $24 million in 2008.

In Georgia’s competitive environment, Marketers including SouthStar, our retail 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.

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Energy Marketing Receivables and Payables

Our wholesale services segment provides services to retail and wholesale marketers and utility and industrial customers. These customers, also known as counterparties, utilize netting agreements, which enable wholesale services to net receivables and payables by counterparty. Wholesale services also nets across product lines and against cash collateral, provided the master netting and cash collateral agreements include such provisions. The amounts due from or owed to wholesale services' counterparties are netted and recorded on our Consolidated Statements of Financial Position as energy marketing receivables and energy marketing payables.

Our wholesale services segment has some 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, wholesale services would need to post collateral to continue transacting business with some of its counterparties. No collateral has been posted under such provisions since our credit ratings have always exceeded the minimum requirements. As of December 31, 2010 and December 31, 2009, the collateral that wholesale services would have been required to post if our credit ratings had been downgraded to non-investment grade status would not have had a material impact to our consolidated results of operations, cash flows or financial condition. However, if such collateral were not posted, wholesale services' ability to continue transacting business with these counterparties would be negatively impacted.

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, 2010 and excluding $61 million of customer deposits, Sequent's top 20 counterparties represented approximately 56% of the total credit exposure of $598 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 BBB+ at December 31, 2010.

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 United States 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 whom it conducts significant transactions.

Fair value measurements

The carrying values of cash and cash equivalents, receivables, derivative financial assets and liabilities, accounts payable, pension and postretirement plan assets and liabilities, other current liabilities and accrued interest approximate fair value. See Note 3 for additional fair value disclosures.

As defined in authoritative guidance related to fair value measurements and disclosures, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in valuing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we use valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We are able to classify fair value balances based on the observance of those inputs. The guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy defined by the guidance are as follows:

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Level 1

Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 items consist of financial instruments with exchange-traded derivatives.

Level 2

Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial and commodity instruments that are valued using valuation methodologies. These methodologies are primarily industry-standard methodologies that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. We obtain market price data from multiple sources in order to value some of our Level 2 transactions and this data is representative of transactions that occurred in the market place. As we aggregate our disclosures by counterparty, the underlying transactions for a given counterparty may be a combination of exchange-traded derivatives and values based on other sources. Instruments in this category include shorter tenor exchange-traded and non-exchange-traded derivatives such as OTC forwards and options.

Level 3

Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to customers' needs. We have no assets or liabilities classified as Level 3, except for retirement plan assets as described in Note 3 and Note 5.

The authoritative guidance related to fair value measurements and disclosures also established a two-step process to determine if the market for a financial asset is inactive and a transaction is not distressed. Currently, this authoritative guidance does not affect us, as our derivative financial instruments are traded in active markets.

Derivative Financial Instruments

Fair Value Hierarchy As required by the authoritative guidance, derivative financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The determination of the fair values incorporates various factors required under the guidance. These factors include not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests), but also the impact of our nonperformance risk on our liabilities.

Netting of Cash Collateral and Derivative Assets and Liabilities under Master Netting Arrangements We maintain accounts with brokers to facilitate financial derivative transactions in support of our energy marketing and risk management activities. Based on the value of our positions in these accounts and the associated margin requirements, we may be required to deposit cash into these broker accounts.

The authoritative guidance related to derivatives and hedging requires that we offset cash collateral held in our broker accounts on our Consolidated Statements of Financial Position with the associated fair value of the instruments in the accounts. Our cash collateral amounts were $105 million as of December 31, 2010 and $57 million as of December

31, 2009.

Natural Gas Derivative Financial Instruments

The fair value of natural gas derivative financial instruments we use to manage exposures arising from changing natural gas prices 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 of our derivative financial instruments.

Distribution Operations In accordance with a directive from the New Jersey BPU, Elizabethtown Gas enters into derivative financial instruments to hedge the impact of market fluctuations in natural gas prices. In accordance with the authoritative guidance related to derivatives and hedging, such derivative transactions are accounted for at fair value each reporting period in our Consolidated Statements of Financial Position. In accordance with regulatory requirements realized gains and losses related to these derivatives are reflected in natural gas costs and ultimately included in billings to customers. However, these derivative financial instruments are not designated as hedges in accordance with the guidance.

Retail Energy Operations We have designated a portion of SouthStar's derivative financial instruments, consisting of financial swaps to manage the risk associated with forecasted natural gas purchases and sales, as cash flow hedges under the authoritative guidance related to derivatives and hedging. 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.

SouthStar currently has minimal hedge ineffectiveness defined as when the gains or losses on the hedging instrument do not offset the losses or gains on the hedged item. This cash flow hedge ineffectiveness is recorded in cost of gas in our Consolidated Statements of Income in the period in which it occurs. We have not designated the remainder of SouthStar's derivative financial instruments as hedges under the authoritative guidance related to derivatives and hedging and, accordingly, we record changes in their fair value within cost of gas in our Consolidated Statements of Income in the period of change.

Wholesale Services 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 OTC 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 sold. These futures contracts meet the definition of derivatives under the authoritative guidance related to derivatives and hedging and are accounted for at fair value in our Consolidated Statements of Financial Position, with changes in fair value recorded in our Consolidated Statements of Income in the period of change. However, these futures contracts are not designated as hedges in accordance with the guidance.

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 fair value basis we utilize for the derivatives used to mitigate the natural gas 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.

Energy Investments During the construction of the storage caverns Golden Triangle Storage uses derivative financial instruments to reduce its exposure to the risk of changes in the price of natural gas that will be purchased in future periods for pad gas. Pad gas includes volumes of non-working natural gas used to maintain the operational integrity of the caverns.

We have designated all of Golden Triangle Storage's derivative financial instruments, consisting of financial swaps, as cash flow hedges under the authoritative guidance related to derivatives and hedging. The pad gas is considered to be a component of the storage cavern's construction costs; as a result, any derivative gains or losses arising from the cash flow hedges will remain in OCI until the pad gas is sold, which will not occur until the storage caverns are decommissioned. The fair value of these derivative financial instruments currently have minimal hedge ineffectiveness which is recorded in cost of gas in our Consolidated Statements of Income in the period in which it occurs. Golden Triangle Storage began entering into these derivative financial transactions during 2009.

Weather Derivative Financial Instruments

SouthStar entered into weather derivative contracts as economic hedges of operating margins in the event of warmer-than-normal and colder-than-normal weather in the Heating Season. SouthStar accounts for these contracts using the intrinsic value method under the authoritative guidance related to financial instruments. These weather derivative financial instruments are not designated as derivatives or hedges and are reflected in cost of gas on our Consolidated Statements of Income.

Debt

We estimate the fair value using a discounted cash flow technique that incorporates a market interest yield curve with adjustments for duration, optionality and risk profile. In determining the market interest yield curve, we considered our currently assigned ratings for unsecured debt.

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Property, Plant and Equipment

A summary of our PP&E by classification as of December 31, 2010 and 2009 is provided in the following table.

| In millions | 2010 | 2009 |
|---|---|---|
| Transmission and distribution | $ 4,955 | $ 4,579 |
| Storage | 580 | 290 |
| Other | 484 | 725 |
| Construction work in progress | 247 | 345 |
| Total gross PP&E | 6,266 | 5,939 |
| Accumulated depreciation | (1,861 ) | (1,793 ) |
| Total net PP&E | $ 4,405 | $ 4,146 |

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, from both debt and equity sources, 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 and Golden Triangle Storage 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 average composite straight-line depreciation rates for depreciable property -- excluding transportation equipment for Atlanta Gas Light, Virginia Natural Gas and Chattanooga Gas and the composite, straight-line rates for Elizabethtown Gas, Florida City Gas and Elkton Gas are listed in the following table. 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 estimated useful life of the asset.

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Atlanta Gas Light | 2.5 % | 2.5 % | 2.5 % |
| Chattanooga Gas | 2.8 % | 3.4 % | 3.3 % |
| Elizabethtown Gas | 2.4 % | 3.1 % | 3.1 % |
| Elkton Gas | 2.3 % | 2.1 % | 2.9 % |

| | | | | | | |
|---|---|---|---|---|---|---|
| Florida City Gas | 3.7 | % | 3.9 | % | 3.9 | % |
| Virginia Natural Gas | 3.0 | % | 2.6 | % | 2.7 | % |

AFUDC and Capitalized Interest

Four of our utilities are authorized by applicable state regulatory agencies or legislatures to record the cost of debt and equity funds as part of the cost of construction projects in our Consolidated Statements of Financial Position. Additionally, we recorded AFUDC of $3 million in 2010, $13 million in 2009 and $8 million in 2008 within the Consolidated Statements of Income. The capital expenditures of our two other utilities do not qualify for AFUDC treatment. More information on our authorized AFUDC rates is provided in the following table.

| | 2010 | | 2009 | | 2008 | |
|---|---|---|---|---|---|---|
| Atlanta Gas Light(1) | 8.10 | % | 8.53 | % | 8.53 | % |
| Chattanooga Gas (2) | 7.41 | % | 7.89 | % | 7.89 | % |
| Elizabethtown Gas (3) | 0.40 | % | 0.41 | % | 2.84 | % |
| Virginia Natural Gas (4) | - | | 9.24 | % | 8.91 | % |

(1) New rate as of November 1, 2010.

(2) New rate as of June 1, 2010.

(3) Variable rate is determined by FERC method of AFUDC accounting.

(4) Approved only for Hampton Roads construction project which ended in 2009. VNG received no AFUDC interest for 2010.

Within our energy investments segment, we have recorded capitalized interest as part of the cost of the Golden Triangle Storage construction project in our Consolidated Statements of Financial Position, and within interest expense in our Consolidated Statements of Income in the amount of $5 million in 2010, $3 million in 2009 and $2 million in 2008.

Goodwill

Goodwill is the excess of the purchase price over the fair value of identifiable net assets acquired in business combinations. In accordance with the authoritative guidance, we annually evaluate our goodwill balances for impairment or more frequently if impairment indicators arise. These indicators include, but are not limited to, a significant change in operating performance, the business climate, legal or regulatory factors, or a planned sale or disposition of a significant portion of the business. We test goodwill impairment utilizing a fair value approach at a reporting unit level which generally equates to our operating segments, as discussed in Note 12 “Segment Information,” and an impairment charge is recognized if the carrying value of a reporting unit’s goodwill exceeds its fair value.

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Our goodwill impairment analysis for the years ended December 31, 2010 and 2009 indicated that the fair value of each reporting unit is substantially in excess of carrying value, and are not at risk of failing step one of the impairment evaluation. As a result, we did not recognize any goodwill impairment charges and do not anticipate taking goodwill impairment charges in the forseeable future.

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 Statements of Financial Position in accordance with authoritative guidance related to income taxes.

Income Taxes We have two categories of income taxes in our Consolidated Statements of 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 Statements of Financial Position. 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 Consolidated Statements of Income for the investment tax credits and other tax credits associated with our non-regulated subsidiaries, including the affordable housing credits.

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 Statements of Financial Position. 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 authoritative guidance related to income taxes, which we are amortizing over approximately 30 years.

Tax Benefits The authoritative guidance related to income taxes requires us to determine whether tax benefits claimed or expected to be claimed on our tax return should be recorded in our consolidated financial statements. Under this guidance, 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 50% likelihood of being realized upon ultimate settlement. This guidance also provides guidance on derecognition, classification, interest and penalties on income taxes, accounting in interim periods and requires increased disclosures. As of December 31, 2010 and December 31, 2009, we did not have a liability for unrecognized tax benefits. Based on current information, we do not anticipate that this will change materially in 2011.

Uncertain Tax Positions 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, 2010, we did not have a liability recorded for payment of interest and penalties associated with uncertain tax positions.

Tax Collections We do not collect income taxes from our customers on behalf of governmental authorities. We collect and remit various taxes on behalf of various governmental authorities. We record these amounts in our Consolidated Statements of Financial Position except taxes in the state of Florida which we are required to include in revenues and operating expenses. These Florida related taxes are immaterial for all 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.

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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. Additionally, 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 Statements of Financial Position 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. In addition, the tariff for Virginia Natural Gas contains a revenue normalization mechanism that mitigates the impact of conservation and declining customer usage.

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 Statements of Financial Position as unbilled revenue. For other commercial and industrial customers and all wholesale customers, revenues are based on actual deliveries during 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 authoritative guidance related to derivatives and hedging 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 and Golden Triangle Storage 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 fixed market-based rates. We recognize our park and loan revenues ratably over the life of the contract.

Cost of gas

Excluding Atlanta Gas Light, we charge our utility customers for natural gas consumed using natural gas cost recovery mechanisms set by the state regulatory agencies. Under these mechanisms, we defer (that is, include as a current asset or liability in the Consolidated Statements of Financial Position 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. These amounts are reflected as regulatory assets identified as recoverable natural gas costs or regulatory liabilities which are identified as deferred natural gas costs within our Consolidated Statements of Financial Position. For more information, see "Regulatory Assets and Liabilities" in Note 2.

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.

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 authoritative guidance related to leases. However, this accounting treatment does not affect the future annual operating lease cash obligations.

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Earnings Per Common Share

We compute basic earnings per common share attributable to AGL Resources Inc. common shareholders by dividing our income attributable to AGL Resources Inc. by the daily weighted average number of common shares outstanding. Diluted earnings per common share attributable to AGL Resources Inc. common shareholders reflect the potential reduction in earnings per common share attributable to AGL Resources Inc. common shareholders 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 share 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. The following table shows the calculation of our diluted shares attributable to AGL Resources Inc. common shareholders 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 | 2010 | 2009 | 2008 |
| --- | --- | --- | --- |
| Denominator for basic earnings per common share attributable to AGL Resources Inc. common shareholders (1) | 77.4 | 76.8 | 76.3 |
| Assumed exercise of potential common shares | 0.4 | 0.3 | 0.3 |
| Denominator for diluted earnings per common share attributable to AGL Resources Inc. common shareholders | 77.8 | 77.1 | 76.6 |

(1) Daily weighted average shares outstanding.

The following table contains the weighted average shares attributable to outstanding stock options that were excluded from the computation of diluted earnings per common share attributable to AGL Resources Inc. because their effect would have been anti-dilutive, as the exercise prices were greater than the average market price:

| | December 31, | | |
| --- | --- | --- | --- |
| In millions | 2010 | 2009 | 2008 |
| Twelve months ended | 0.8 | 2.0 | 1.6 |

The decrease in the number of shares that were excluded from the computation for the year ended December 31, 2010 is the result of an increase in the average market value of our common shares for the years ended December 31, 2010 compared to 2009 and 2008. While the market value of our common shares rose during 2009, the average share price for 2009 was lower than 2008.

Regulatory Assets and Liabilities

We account for the financial effects of regulation in accordance with authoritative guidance related to regulated entities whose rates are designed to recover the costs of providing service. In accordance with this guidance, incurred costs and estimated future expenditures that would otherwise be charged to expense are capitalized and recorded as regulatory assets when it is probable that the incurred costs or estimated future expenditures will be recovered in rates in the future. Similarly, we recognize regulatory liabilities when it is probable that regulators will require customer refunds through future rates or when revenue is collected from customers for expenditures that have not yet been incurred. Generally, regulatory assets are amortized into expense and regulatory liabilities are amortized into income over the period authorized by the regulatory commissions.

Our regulatory assets and liabilities and the associated assets and liabilities are summarized in the following table.

| | December 31, | |
|---|---|---|
| In millions | 2010 | 2009 |
| Regulatory assets | | |
| Recoverable regulatory infrastructure program costs | $ 292 | $ 266 |
| Recoverable ERC | 171 | 172 |
| Recoverable seasonal rates | 11 | 11 |
| Recoverable postretirement benefit costs | 9 | 10 |
| Recoverable natural gas costs | 3 | - |
| Other | 35 | 27 |
| Total regulatory assets | 521 | 486 |
| Associated assets | | |
| Derivative financial instruments | 20 | 11 |
| Total regulatory and associated assets | $ 541 | $ 497 |
| Regulatory liabilities | | |
| Accumulated removal costs | $ 182 | $ 183 |
| Derivative financial instruments | 20 | 11 |
| Deferred natural gas costs | 19 | 30 |
| Regulatory tax liability | 15 | 17 |
| Unamortized investment tax credit | 12 | 13 |
| Other | 24 | 17 |
| Total regulatory liabilities | 272 | 271 |
| Associated liabilities | | |
| Regulatory infrastructure program costs | 228 | 210 |
| ERC | 132 | 133 |
| Total associated liabilities | 360 | 343 |
| Total regulatory and associated liabilities | $ 632 | $ 614 |

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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 recoverable through base rates are subject to review by the respective state regulatory commission during any future rate proceedings. We are not aware of any evidence that these costs will not be recoverable through either rate riders or base rates, and believe that we will be able to recover these costs, consistently with our historical recoveries. In the event that the provisions of authoritative guidance related to regulated operations were no longer applicable, we would recognize a write-off of regulatory assets that would result in a charge to net income, and be classified as an extraordinary item.

Additionally, the regulatory liabilities would not be written-off but would continue to be recorded as liabilities but not as regulatory liabilities. 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 the guidance 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. 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.

All the regulatory assets included in the preceding table are included in base rates except for the recoverable regulatory infrastructure program costs, recoverable ERC and deferred natural gas costs, which are recovered through specific rate riders on a dollar for dollar basis. The rate riders that authorize recovery of recoverable regulatory infrastructure program costs and the deferred natural gas costs include both a recovery of costs and a return on investment during the recovery period.

Environmental Remediation Costs Our ERC liabilities are customarily reported estimates of future remediation costs for our former operating sites that are contaminated based on probabilistic models of potential costs and on an undiscounted basis. As cleanup options and plans mature and cleanup contracts are entered into, we are able to provide conventional engineering estimates of the likely costs of remediation at our former sites. These estimates contain various engineering uncertainties, but we continuously attempt to refine and update these engineering estimates. 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 we may be held liable but for which we cannot reasonably estimate an amount.

Our ERC liabilities are included as a corresponding regulatory asset. These recoverable ERC assets are a combination of accrued ERC liabilities and recoverable cash expenditures for investigation and cleanup costs. We primarily recover these costs through rate riders. We have two rate riders that authorize the recovery of these costs. 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 recoverable amounts not currently in rates. For more information on our ERC liabilities, see Note 10.

Derivative Financial Instruments Elizabethtown Gas' derivative financial instrument asset and liability reflect unrealized losses or gains that will be recovered from or passed to rate payers through the recovery of its natural gas costs on a dollar for dollar basis, once the losses or gains are realized. For more information on Elizabethtown Gas' derivative financial instruments, see Note 4.

Other Regulatory Assets and Liabilities Our recoverable postretirement benefit costs are recoverable through base rates over the next 3 to 22 years based on the remaining recovery period as designated by the applicable state regulatory commissions. Recoverable 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. These amounts are fully recoverable through base rates within one year.

Regulatory Infrastructure Programs By order of the Georgia Commission (through a joint stipulation and a subsequent settlement agreement between Atlanta Gas Light and the Georgia Commission) Atlanta Gas Light began a pipeline replacement program to replace all bare steel and cast iron pipe in its system by December 2013. If Atlanta Gas Light does not perform in accordance with this order, it will be assessed certain nonperformance penalties. As of 2010, we have completed the replacement of all our cast iron pipes, and the remaining replacements are on schedule.

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The order 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

Atlanta Gas Light has recorded a long-term regulatory asset of $244 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 $48 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:

- $45 million in 2010
- $41 million in 2009
- $30 million in 2008

As of December 31, 2010, Atlanta Gas Light had recorded a current liability of $62 million representing expected program expenditures for the next 12 months and a long-term liability of $166 million, representing expected program expenditures starting in 2011 through the end of the program in 2013.

Atlanta Gas Light capitalizes and depreciates the capital expenditure costs incurred from the pipeline replacement program 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 pipeline replacement program 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.

The Georgia Commission has also approved Atlanta Gas Light’s STRIDE program, which is comprised of the ongoing pipeline replacement program, the new Integrated System Reinforcement Program (i-SRP) and the new Integrated Customer Growth Program (i-CGP). Under STRIDE the purpose of the i-SRP program is to upgrade Atlanta Gas Light’s distribution system and liquefied natural gas facilities in Georgia, improve its system reliability and operational flexibility, and create a platform to meet long-term forecasted growth. Under STRIDE, Atlanta Gas Light will be required to file an updated ten-year forecast of infrastructure requirements under the i-SRP along with a new three-year construction plan every three years for review and approval by the Georgia Commission.

Under the i-CGP program, the Georgia Commission authorized Atlanta Gas Light to extend the company’s pipeline facilities to serve customers without pipeline access and create new economic development opportunities in Georgia. The i-CGP was approved as a three-year pilot program under STRIDE, and will be recovered through a surcharge.

In April 2009, the New Jersey BPU approved an enhanced infrastructure program for Elizabethtown Gas, which began in 2009 and is scheduled to be completed in 2011. This program was created in response to the New Jersey Governor’s request for utilities to assist in the economic recovery by increasing infrastructure investments. A regulatory cost recovery mechanism will be established with estimated rates put into effect at the beginning of each year. At the end of the program the regulatory cost recovery mechanism will be trued-up and any remaining costs not previously collected will be included in base rates.

The following table provides additional information on our expenditures under these programs during the year ended December 31, 2010.

| In millions | |
|---|---|
| Georgia | |
| Pipeline replacement program | $ 81 |
| Integrated System Reinforcement Program | 54 |
| Integrated Customer Growth Program | 6 |
| New Jersey | |
| Enhanced infrastructure program | 46 |
| Total | $ 187 |

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Accounting for employee benefit plans

The authoritative guidance related to retirement benefits requires that we recognize all obligations related to defined benefit pensions and other postretirement benefits and quantify the plans' funding status as an asset or a liability on our Consolidated Statements of Financial Position. The guidance 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 authoritative guidance related to pension and postretirement benefits. Our retirement and postretirement plans' assets were accounted for at fair value and are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

Non-Wholly-Owned Entities

We hold ownership interests in a number of joint ventures with varying ownership structures. We evaluate all of our partnership interests and other variable interests to determine if each entity is a variable interest entity (VIE), as defined in the authoritative accounting guidance. If a venture is a VIE for which we are the primary beneficiary, we consolidate the assets, liabilities and results of operations of the entity. We reassess our conclusion as to whether an entity is a VIE upon certain occurrences which are deemed reconsideration events under the guidance.

On January 1, 2010, we adopted authoritative accounting guidance that requires us to reassess our determination that we are the primary beneficiary of a VIE based on whether we have the power to direct matters that most significantly impact the activities of a VIE, and have the obligation to absorb losses or the right to receive benefits of a VIE. The adoption of this guidance had no effect on our Consolidated Statements of Income, Cash Flows or Financial Position because we concluded that SouthStar's accounts should continue to be consolidated with the accounts of AGL Resources Inc. and its majority-owned and controlled subsidiaries.

We have concluded that the only joint venture that we are required to consolidate as a VIE, for which we are the primary beneficiary, is SouthStar. We recognize on our Consolidated Statements of Financial Position, Piedmont's share of the non-wholly owned entity as a separate component of equity entitled "noncontrolling interest." Piedmont's share of current operations is reflected in "net income attributable to the noncontrolling interest" on our Consolidated Statements of Income. The authoritative guidance has no effect on our calculation of basic or diluted earnings per common share amounts, which are based upon net income attributable to AGL Resources Inc. For additional information, see Note 9.

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. Our estimates may 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 pipeline replacement program 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.

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Note 3 – Fair Value Measurements

The methods used to determine fair value for our assets and liabilities are fully described within Note 2.

Derivative Financial Instruments

The following table summarizes, by level within the fair value hierarchy, our derivative financial assets and liabilities that were accounted for at fair value on a recurring basis for the years ended December 31, 2010 and 2009.

| | Recurring fair values Natural gas derivative financial instruments | | | |
|---|---|---|---|---|
| | December 31, 2010 | | December 31, 2009 | |
| In millions | Assets (1) | Liabilities | Assets (1) | Liabilities |
| Quoted prices in active markets (Level 1) | $ 22 | $ (71) | $ 36 | $ (37) |
| Significant other observable inputs (Level 2) | 153 | (29) | 172 | (52) |
| Unobservable inputs (Level 3) | - | - | - | - |
| Netting of cash collateral | 53 | 52 | 30 | 27 |
| Total carrying value (2) | $ 228 | $ (48) | $ 238 | $ (62) |

(1) Less than $1 million of premium at December 31, 2010 and $2 million at December 31, 2009 associated with weather derivatives have been excluded as they are based on intrinsic value not fair value.

(2) There were no transfers between Level 1, Level 2, or Level 3 for any periods presented.

Other Fair Value Measures

In addition to our derivative financial instruments above, we have several financial and nonfinancial assets and liabilities subject to fair value measures. These financial assets and liabilities include cash and cash equivalents, accounts receivable, accounts payable and debt. For cash and cash equivalents, accounts receivable and accounts payable, we consider carrying value to materially approximate fair value due to their short-term nature. The nonfinancial assets and liabilities include pension and post-retirement benefits.

Pension and post-retirement benefits Our pension and postretirement target asset allocations consist of approximately 30% - 95% equity, 10% - 40% fixed income, 10% - 35% real estate and other and the remaining 0% - 10% in cash. Our actual retirement and postretirement plans' asset allocations by level within the fair value hierarchy for the year ended December 31, 2010, are presented in the table below.

| | Retirement plans (1) | | | | | Postretirement plan | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| In millions | Level 1 | Level 2 | Level 3 | Total | % of total | Level 1 | Level 2 | Level 3 | Total | % of total |
| Cash | $7 | $- | $- | $7 | 2 % | $1 | $- | $- | $1 | 1 % |
| Equity Securities | | | | | | | | | | |
| U.S. large cap (2) | 91 | - | - | 91 | 26 % | - | 36 | - | 36 | 57 % |
| U.S. small cap (2) | 51 | - | - | 51 | 15 % | - | - | - | - | - |
| International companies (3) | - | 43 | | 43 | 12 % | - | 12 | - | 12 | 19 % |
| Emerging markets (4) | - | 16 | - | 16 | 4 % | - | - | - | - | - |
| Fixed income securities | | | | | | | | | | |
| Corporate bonds (5) | - | 56 | - | 56 | 16 % | - | 15 | - | 15 | 23 % |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Other types of investments | | | | | | | | | | |
| Global hedged equity (6) | - | - | 35 | 35 | 10 % | - | - | - | - | - |
| Absolute return (7) | - | - | 30 | 30 | 9 % | - | - | - | - | - |
| Private capital (8) | - | - | 22 | 22 | 6 % | - | - | - | - | - |
| Total assets at fair value | $149 | $115 | $87 | $351 | 100 % | $1 | $63 | $- | $64 | 100 % |
| % of fair value hierarchy | 42 % | 33 % | 25 % | 100 % | | 1 % | 99 % | - | 100 % | |

(1) Includes $7 million of medical benefit (health and welfare) component for 401h accounts to fund a portion of the postretirement obligation.

(2) Includes funds that invest primarily in United States common stocks.

(3) Includes funds that invest primarily in foreign equity and equity-related securities.

(4) Includes funds that invest primarily in common stocks of emerging markets.

(5) Includes funds that invest primarily in investment grade debt and fixed income securities.

(6) Includes funds that invest in limited / general partnerships, managed accounts, and other investment entities issued by non-traditional firms or “hedge funds.”

(7) Includes funds that invest primarily in investment vehicles and commodity pools as a “fund of funds.”

(8) Includes funds that invest in private equity and small buyout funds, partnership investments, direct investments, secondary investments, directly / indirectly in real estate and may invest in equity securities of real estate related companies, real estate mortgage loans, and real-estate mezzanine loans.

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The following is a reconciliation of assets in Level 3 of the fair value hierarchy.

| | Fair value measurements using significant unobservable inputs – Level 3 | | | | |
|---|---|---|---|---|---|
| In millions | Global hedged equity | Absolute return | Private capital | Equity Security - international companies | Total |
| Assets: | | | | | |
| Beginning balance | $ 33 | $ 26 | $ 13 | $ 5 | $ 77 |
| Transfers out of Level 3 (1) | - | - | - | (4) | (4) |
| Gains included in changes in net assets | 2 | 2 | 2 | - | 6 |
| Purchases and issuances | - | 14 | 8 | - | 22 |
| Sales and settlements | - | (12) | (1) | (1) | (14) |
| Ending balance | $ 35 | $ 30 | $ 22 | $ - | $ 87 |

(1) Transferred to Level 2 as a result of change in investment vehicle and pricing inputs becoming directly observable.

Debt Our debt is recorded at carrying value. We estimate the fair value of our debt using a discounted cash flow technique that incorporates a market interest yield curve with adjustments for duration, optionality and risk profile. In determining the market interest yield curve, we considered our currently assigned ratings for unsecured debt. The following table presents the carrying value and fair value of our debt for the years ended December 31, 2010 and 2009:

| | As of December 31, | |
|---|---|---|
| In millions | 2010 | 2009 |
| Carrying amount | $ 2,706 | $ 2,576 |
| Fair value | $ 2,122 | $ 2,060 |

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Note 4 – Derivative Financial Instruments

Derivative Financial Instruments

Our risk management activities are monitored by our Risk Management Committee, which consists of members of senior management and is charged with reviewing and enforcing our risk management activities and policies. Our use of derivative financial instruments and physical transactions is limited to predefined risk tolerances associated with pre-existing or anticipated physical natural gas sales and purchases and system use and storage. We use the following types of derivative financial instruments and physical transactions to manage natural gas price, interest rate, weather, automobile fuel price 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

Our derivative financial instruments do not contain any material credit-risk-related or other contingent features that could increase the payments for collateral we post in the normal course of business when our financial instruments are in net liability positions. Our energy marketing receivables and payables, which do have credit-risk-related or other contingent features, are discussed in Note 2. Our derivative financial instrument activities are included within operating cash flows as an adjustment to net income of $(2) million in 2010, $11 million in 2009 and $(129) million in 2008. The table below summarizes the various ways in which we account for our derivative instruments and the impact on our Consolidated Financial Statements:

| | Recognition and Measurement | |
|---|---|---|
| Accounting Treatment | Statement of Financial Position | Income Statement |
| Cash flow hedge | Recorded at fair value | Ineffective portion of the gain or loss on the derivative instrument is recognized in earnings |
| | Effective portion of the gain or loss on the derivative instrument is reported initially as a component of accumulated other comprehensive income (loss) | Effective portion of the gain or loss on the derivative instrument is reclassified out of accumulated other comprehensive income (loss) into earnings when the forecasted transaction affects earnings |
| Not designated as hedges | Recorded at fair value | The gain or loss on the derivative instrument is recognized in earnings |
| | Elizabethtown Gas' derivative financial instruments are recorded as a regulatory asset or liability until included in cost of gas | The gain or loss on these derivative instruments is reflected in cost of gas and is ultimately included in billings to customers |
| | Change in fair value of the derivative instrument is recorded as an adjustment to book value | Change in fair value of the derivative instrument is recognized in earnings |

Interest Rate Swaps

In May 2010, as a result of an anticipated refinancing of senior notes that matured in January 2011, we entered into $200 million of forward interest rate swaps, with a treasury rate of 3.94%. We designated the forward interest rate swap as a cash flow hedge against the first 20 future semi-annual interest payments of debt securities. In December 2010 we settled the interest rate swaps for a cost of $7 million, which is included within financing cash flows.

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Quantitative Disclosures Related to Derivative Financial Instruments

As of December 31, 2010 and 2009, our derivative financial instruments were comprised of both long and short natural gas positions. A long position is a contract to purchase natural gas, and a short position is a contract to sell natural gas. As of December 31, 2010 and 2009, we had net long natural gas contracts outstanding in the following quantities:

Natural gas contracts

| In Bcf | December 31, 2010 (1) | December 31, 2009 |
|---|---|---|
| Hedge designation: | | |
| Cash flow | 4 | 5 |
| Not designated | 220 | 108 |
| Total | 224 | 113 |
| Hedge position: | | |
| Short | (1,605) | (1,518) |
| Long | 1,829 | 1,631 |
| Net long position | 224 | 113 |

(1) Approximately 96% of these contracts have durations of two years or less and the remaining 4% expire in 3 to 6 years.

Derivative Financial Instruments on the Consolidated Statements of Income

The following table presents the gain or (loss) on derivative financial instruments in our Consolidated Statements of Income.

| In millions | For the twelve months ended December 31, 2010 | 2009 |
|---|---|---|
| Designated as cash flow hedges | | |
| Natural gas contracts – loss reclassified from OCI into cost of gas for settlement of hedged item | $ (16) | $ (31) |
| Not designated as hedges | | |
| Natural gas contracts – fair value adjustments recorded in operating revenues (1) | (1) | 21 |
| Natural gas contracts – net gain fair value adjustments recorded in cost of gas (2) | (2) | 1 |
| Total losses on derivative instruments | $ (19) | $ (9) |

(1) Associated with the fair value of existing derivative instruments at December 31, 2010 and 2009.
(2) Excludes losses recorded in cost of gas associated with weather derivatives of $27 million for the year ended December 31, 2010 and $6 million for the year ended December 31, 2009.

Our expected net loss to be reclassified from OCI into cost of gas and recognized in our Consolidated Statements of Income over the next twelve months is less than $1 million. These pre-tax deferred losses recorded in OCI are associated with retail energy operations' derivative instruments and are based upon the fair values of these financial instruments.

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Derivative Financial Instruments on the Consolidated Statements of Financial Position

In accordance with regulatory requirements, $35 million of realized losses on derivative financial instruments used at Elizabethtown Gas in our distribution operations segment were reflected in deferred natural gas costs within our Consolidated Statements of Financial Position during the year ended December 31, 2010 and $38 million during the year ended December 31, 2009. The following table presents the fair value and Consolidated Statements of Financial Position classification of our derivative financial instruments:

| In millions | Statement of financial position location (1) (2) | December 31, 2010 | 2009 |
|---|---|---|---|
| Designated as cash flow hedges | | | |
| Asset Financial Instruments | | | |
| Current natural gas contracts | Derivative financial instruments assets and liabilities – current portion | $ 3 | $ 6 |
| Noncurrent natural gas contracts | Derivative financial instruments assets and liabilities | - | - |
| Liability Financial Instruments | | | |
| Current natural gas contracts | Derivative financial instruments assets and liabilities – current portion | (5 ) | (5 ) |
| Total | | (2 ) | 1 |
| Not designated as cash flow hedges | | | |
| Asset Financial Instruments | | | |
| Current natural gas contracts | Derivative financial instruments assets and liabilities – current portion | 541 | 590 |
| Noncurrent natural gas contracts | Derivative financial instruments assets and liabilities | 105 | 118 |
| Liability Financial Instruments | | | |
| Current natural gas contracts | Derivative financial instruments assets and liabilities – current portion | (489 ) | (510 ) |
| Noncurrent natural gas contracts | Derivative financial instruments assets and liabilities | (80 ) | (78 ) |
| Total | | 77 | 120 |
| Total derivative financial instruments | | $ 75 | $ 121 |

(1) These amounts are netted within our Consolidated Statements of Financial Position. Some of our derivative financial instruments have asset positions which are presented as a liability in our Consolidated Statements of Financial Position, and we have derivative instruments that have liability positions which are presented as an asset in our Consolidated Statements of Financial Position.

(2) As required by the authoritative guidance related to derivatives and hedging, the fair value amounts above are presented on a gross basis. As a result, the amounts above do not include cash collateral held on deposit in broker margin accounts of $105 million as of December 31, 2010 and $57 million as of December 31, 2009. Accordingly, the amounts above will differ from the amounts presented on our Consolidated Statements of Financial Position, and the fair value information presented for our derivative financial instruments in the recurring values table in Note 3.

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Note 5 - Employee Benefit Plans

Oversight of Plans

The Retirement Plan Investment Committee (the Committee) appointed by our Board of Directors is responsible for overseeing the investments of our retirement plans. Further, we have an Investment Policy (the Policy) for our retirement and postretirement benefit plans aimed to preserve these plans' capital and maximize investment earnings in excess of inflation within acceptable levels of capital market volatility. To accomplish this goal, the retirement and postretirement benefit plans' assets are actively managed to optimize long-term return while maintaining a high standard of portfolio quality and diversification.

We will continue to diversify retirement plan investments to minimize the risk of large losses in a single asset class. We do not have a concentration of assets in a single entity, industry, country, commodity or class of investment fund. The Policy's permissible investments include domestic and international equities (including convertible securities and mutual funds), domestic and international fixed income (corporate and United States government obligations), cash and cash equivalents and other suitable investments.

Equity market performance and corporate bond rates have a significant effect on our reported unfunded projected benefit obligation (PBO) and accumulated postretirement benefit obligation (APBO), as the primary factors that drive the value of our unfunded PBO and APBO 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 used by our largest pension plan. The MRVPA is a calculated value and differs from the actual market value of plan assets. The MRVPA also 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.

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 used this benefit formula for such participants until December 31, 2010, at which time any of those participants who were still actively employed accrued future benefits under the career average earnings formula.

The NUI Retirement Plan covers substantially all of NUI Corporation's employees who were employed on or before December 31, 2005, except Florida City Gas union employees, who until February 2008 participated in a union-sponsored multiemployer plan. Pension benefits are based on years of credited service and final average compensation as of the plan freeze date. Effective January 1, 2006, participation and benefit accrual under the NUI Retirement Plan were frozen. As of that date, former participants in that plan became eligible to participate in the AGL Retirement Plan. Florida City Gas union employees became eligible to participate in the AGL Retirement Plan in February 2008.

Postretirement Benefits

We sponsor a defined benefit postretirement health care plan for our eligible employees, the Health and Welfare Plan for Retirees and Inactive Employees of AGL Resources Inc. (AGL Postretirement Plan). Eligibility for these benefits is based on age and years of service.

The AGL Postretirement Plan includes medical coverage for all eligible AGL Resources employees who were employed as of June 30, 2002, if they reach retirement age while working for us. In addition, the AGL Postretirement Plan provides life insurance for all employees if they have ten years of service at retirement. 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 $9 million as of December 31, 2010 and $10 million as of December 31, 2009. In addition, we recorded a regulatory liability of $6 million as of December 31, 2010 and $5 million as of December 31, 2009 for our expected expenses under the AGL Postretirement Plan. We expect to pay $8 million of insurance claims for the postretirement plan in 2011, but we do not anticipate making any additional contributions.

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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.

From January 1, through June 30, 2009, Medicare-eligible participants received prescription drug benefits through a Medicare Part D plan offered by a third party and to which we subsidized participant premiums. Medicare-eligible retirees who opted out of the AGL Postretirement Plan were eligible to receive a cash subsidy which could be used towards eligible prescription drug expenses. Effective July 1, 2009, Medicare eligible retirees, including all of those at least age 65, receive benefits through our contribution to a retiree health reimbursement arrangement account.

Effective January 1, 2010, enhancements were made to the pre-65 medical coverage by removing the current cap on our expected costs and implementing a new cap determined by the new retiree premium schedule based on salary level and years of service. Consequently, there is no impact on the periodic benefit cost or on our accumulated projected benefit obligation for the AGL postretirement plan for a change in the assumed healthcare cost trend.

Contributions

Our employees do not contribute to the retirement plans. We fund the qualified pension 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. As required by The Pension Protection Act of 2006 (the Act), we calculate the minimum amount of funding using the traditional unit credit cost method.

The Act contained new funding requirements for single employer defined benefit pension plans. The Act established a 100% funding target (over a 7-year amortization period) for plan years beginning after December 31, 2007. If certain conditions are met, the Worker, Retiree and Employer Recovery Act of 2008 (passed December 2008) allowed us to measure our minimum required contributions based on a funding target at 96% in 2009 and 100% in 2010. In 2010 we contributed $31 million to our qualified pension plans. In 2009 we contributed $24 million to our qualified pension plans. For more information on our 2011 contributions to our pension plans, see Note 10.

Funded status

Based on the funded status of our defined benefit pension and postretirement benefit plans as of December 31, 2010, we reported an after-tax loss to our OCI of $28 million ($48 million before tax), a net increase of $25 million to accrued pension and postretirement obligations and a decrease of $20 million to accumulated deferred income taxes.

Assumptions

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.

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, and other high-grade bond indices a single equivalent discount rate derived with the assistance of our actuaries by matching expected future cash flows in each year to the appropriate spot rates based in high quality (rated

AA or better) corporate bonds.

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The following tables present details about our AGL Retirement Plan and the NUI Retirement Plan (retirement plans) and the AGL Postretirement Plan (postretirement plan).

| | Retirement plans | | Postretirement plan | |
|---|---|---|---|---|
| Dollars in millions | 2010 | 2009 | 2010 | 2009 |
| Change in plan assets | | | | |
| Fair value of plan assets, January 1, | $ 303 | $ 242 | $ 63 | $ 49 |
| Actual return on plan assets | 37 | 61 | 8 | 14 |
| Employer contribution | 31 | 26 | 7 | 7 |
| Benefits paid | (27) | (26) | (7) | (7) |
| Fair value of plan assets, December 31, | $ 344 | $ 303 | $ 71 | $ 63 |
| Change in benefit obligation | | | | |
| Benefit obligation, January 1, | $ 463 | $ 442 | $ 101 | $ 95 |
| Service cost | 11 | 8 | - | - |
| Interest cost | 27 | 26 | 6 | 6 |
| Plan amendment | - | - | - | 1 |
| Actuarial loss | 57 | 13 | 7 | 6 |
| Benefits paid | (27) | (26) | (7) | (7) |
| Benefit obligation, December 31, | $ 531 | $ 463 | $ 107 | $ 101 |
| Funded status at end of year | $ (187) | $ (160) | $ (36) | $ (38) |
| Amounts recognized in the Consolidated Statements of Financial Position consist of | | | | |
| Current liability | $ (1) | $ (1) | $ - | $ - |
| Long-term liability | (186) | (159) | (36) | (38) |
| Total liability at December 31, | $ (187) | $ (160) | $ (36) | $ (38) |
| Assumptions used to determine benefit obligations | | | | |
| Discount rate | 5.2 - 5.4 % | 5.8 - 6.0 % | 5.2 % | 5.8 % |
| Rate of compensation increase | 3.7 % | 3.7 % | 3.7 % | 3.7 % |
| Accumulated benefit obligation | $ 506 | $ 448 | Not applicable | |

The components of our pension and postretirement benefit costs are set forth in the following table.

| | Retirement plans | | | Postretirement plan | | |
|---|---|---|---|---|---|---|
| Dollars in millions | 2010 | 2009 | 2008 | 2010 | 2009 | 2008 |
| Net benefit cost | | | | | | |
| Service cost | $ 11 | $ 8 | $ 7 | $ - | $ - | $ - |
| Interest cost | 27 | 26 | 26 | 6 | 6 | 6 |
| Expected return on plan assets | (28) | (29) | (32) | (5) | (4) | (6) |
| Net amortization | (2) | (2) | (2) | (4) | (4) | (4) |
| Recognized actuarial loss | 10 | 9 | 3 | 2 | 2 | 1 |
| Net annual pension cost | $ 18 | $ 12 | $ 2 | $ (1) | $ - | $ (3) |
| Assumptions used to determine benefit costs | | | | | | |
| Discount rate | 5.8 - 6.0 % | 6.2 % | 6.4 % | 5.8 % | 6.2 % | 6.4 % |
| Expected return on plan assets | 8.75 % | 9.0 % | 9.0 % | 8.75 % | 9.0 % | 9.0 % |
| Rate of compensation increase | 3.7 % | 3.7 % | 3.7 % | 3.7 % | 3.7 % | 3.7 % |

There were no other changes in plan assets and benefit obligations recognized for our retirement and postretirement plans for the year ended December 31, 2010. The 2011 estimated OCI amortization for these plans are set forth in the following table.

| In millions | Retirement plans | Postretirement plan |
|---|---|---|
| Amortization of prior service credit | $ (2 ) | $ (4 ) |
| Amortization of net loss | 14 | 2 |

The following table presents expected benefit payments for the years ended December 31, 2011 through 2020 for our retirement and postretirement plans. There will be benefit payments under these plans beyond 2020.

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| In millions | Retirement plans | Postretirement plan |
|---|---|---|
| 2011 | $ 29 | $ 8 |
| 2012 | 29 | 8 |
| 2013 | 29 | 7 |
| 2014 | 30 | 7 |
| 2015 | 31 | 7 |
| 2016-2020 | 168 | 38 |
| Total | $ 316 | $ 75 |

The following table presents the amounts not yet reflected in net periodic benefit cost and included in accumulated OCI as of December 31, 2010.

| In millions | Retirement plans | Postretirement plan |
|---|---|---|
| Prior service credit | $ (15 ) | $ (8 ) |
| Net loss | 226 | 35 |
| Accumulated OCI | 211 | 27 |
| Net amount recognized in Consolidated Statements of Financial Position | (187 ) | (36 ) |
| Prepaid (accrued) cumulative employer contributions in excess of net periodic benefit cost | $ 24 | $ (9 ) |

There were no other changes in plan assets and benefit obligations recognized in our retirement and postretirement plans for the year ended December 31, 2010.

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 of $7 million in 2010, $7 million in 2009 and $6 million in 2008.

Note 6 – 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 (1) | Shares available for future issuance | Details |
|---|---|---|---|
| Omnibus Performance Incentive Plan | 1,109,284 | 3,693,004 | 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) | 1,745,377 | - | Grants of incentive and nonqualified stock options, shares of restricted stock and performance units to key employees. |
| Officer Incentive Plan | 41,438 | 211,409 | Grants of nonqualified stock options and shares of restricted stock to new-hire officers. |
| | not applicable | 140,812 | |

| | | | |
|---|---|---|---|
| 2006 Non-Employee Directors Equity Compensation Plan | | | 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 | 29,653 | 14,304 | 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 | 198,048 | Nonqualified, broad-based employee stock purchase plan for eligible employees. |

(1) As of December 31, 2010.

(2) Following shareholder approval of the Omnibus Performance Incentive Plan in 2008, no further grants will be made except for reload options that may be granted under the plan's outstanding options.

Glossary of Key Terms

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Accounting Treatment and Compensation Expense

The authoritative guidance related to stock compensation requires us to measure and recognize stock-based compensation expense over the required service period 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
- 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.

We estimate forfeitures over the required 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. The authoritative guidance requires excess tax benefits to be reported as a financing cash inflow. The difference between the proceeds from the exercise of our stock-based awards and the par value of the stock is recorded within premium on common stock.

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. The following table provides additional information on compensation costs and income tax benefits and excess tax benefits related to our cash and stock-based compensation awards.

| In millions | 2010 | 2009 | 2008 |
|---|---|---|---|
| Compensation costs (1) | $ 11 | $ 11 | $ 10 |
| Income tax benefits (1) | 2 | 2 | 1 |
| Excess tax benefits (2) | 2 | 2 | 1 |

(1) Recorded in our Consolidated Statements of Income.
(2) Recorded in our Consolidated Statements of Cash Flows.

Incentive and Nonqualified Stock Options

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.

As of December 31, 2010, we had an immaterial amount of unrecognized compensation costs related to stock options. Cash received from stock option exercises for 2010 was $9 million, and the income tax benefit from stock option exercises was less than $1 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 | Aggregate intrinsic value (in |
|---|---|---|---|---|

| | | | | life (in years) | millions) |
|---|---|---|---|---|---|
| Outstanding – December 31, 2007 | 2,517,498 | $ | 33.28 | | |
| Granted | 258,017 | | 38.70 | | |
| Exercised | (212,600 ) | | 23.53 | | |