Attachment 1

AGL Resources Inc.'s
Tax Sharing Agreement

Attachment 1 is Confidential

Attachment 2

Elizabethtown Gas Company
Form 1120
2008 - 2011

Attachment 2 is Confidential

Attachment 3

AGL Resources Inc.
2008 – 2011 Federal Consolidated Tax Returns

Attachment 3 is Confidential

Attachment 4

Total Federal Income Taxes Paid By AGL Resources Inc.
2008 – 2011

Attachment 4 is Confidential

Attachment 5

Bonus Depreciation Taken
By AGL Resources Inc.
Consolidated Tax Group
2002 – 2011

Attachment 5 is Confidential

Attachment 6

Alternative Minimum Tax Payments By AGL Resources Inc.

2008 – 2011

Attachment 6 is Confidential

Attachment 7

AGL Resources Inc.
Operating Loss Carryovers

Attachment 7 is Confidential

Attachment 8

AGL Resources Inc.’s

2012 Annual Report

PRELIMINARY PUBLIC COPY

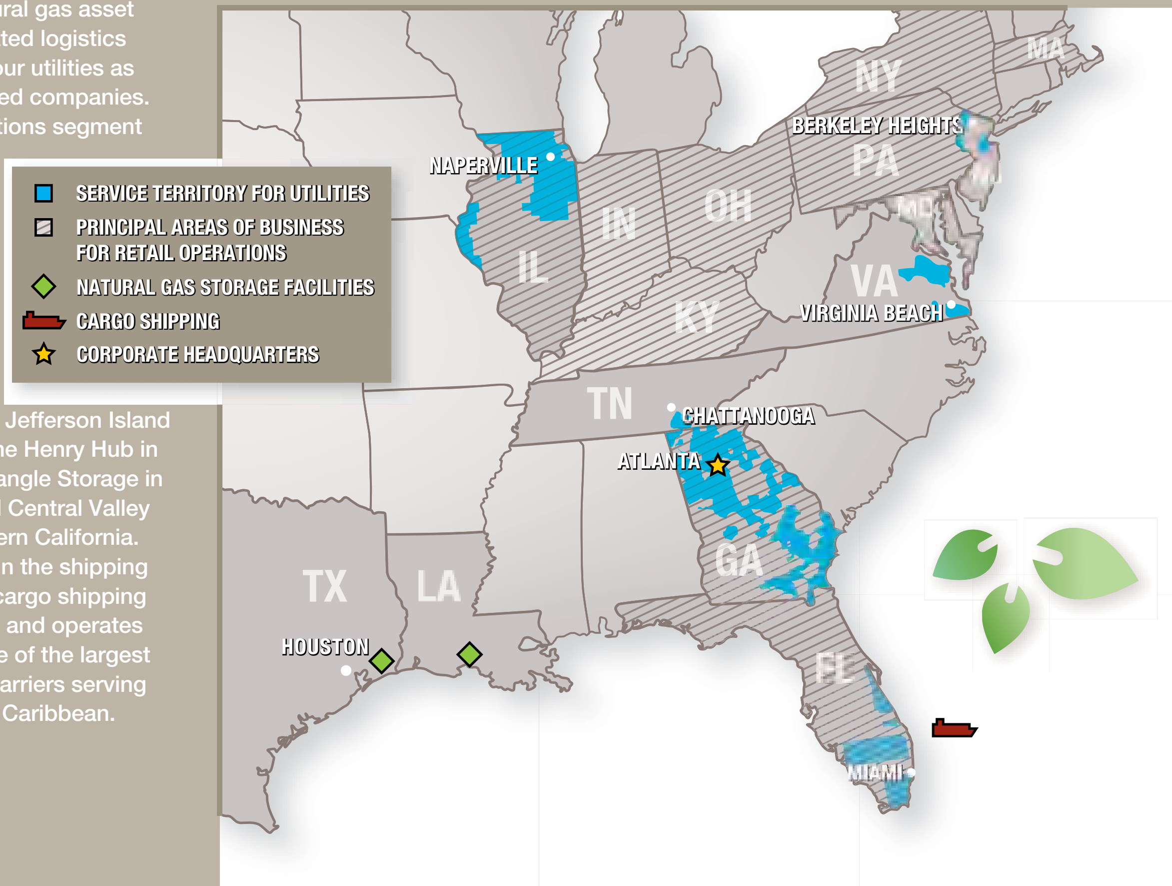
AGL Resources™

Expanding Opportunities

2012 Annual Report

Corporate Overview

AGL Resources serves approximately 4.5 million end-use customers in seven states through its utility subsidiaries within the distribution operations segment: Nicor Gas in Illinois, Atlanta Gas Light in Georgia, Virginia Natural Gas in Virginia, Elizabethtown Gas in New Jersey, Florida City Gas in Florida, Chattanooga Gas in Tennessee and Elkton Gas in Maryland. Our retail operations segment serves approximately 1.5 million retail customers and markets natural gas and related home services to end-use customers in more than 9 states. Our Houston based wholesale services segment provides natural gas storage and arbitrage and related activities, natural gas asset management and related logistics activities for each of our utilities as well as for non-affiliated companies. Our midstream operations segment provides natural gas storage arbitrage and related activities and engages in the development and operation of high-deliverability natural gas storage assets. These include Jefferson Island Storage & Hub near the Henry Hub in Louisiana, Golden Triangle Storage in Beaumont, Texas and Central Valley Gas Storage, in northern California. We are also involved in the shipping industry through our cargo shipping segment, which owns and operates Tropical Shipping, one of the largest containerized cargo carriers serving the Bahamas and the Caribbean.

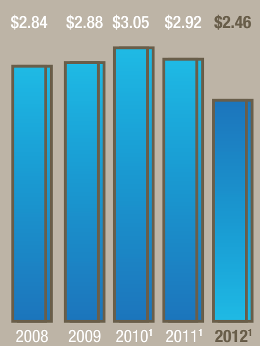


Financial Highlights

In millions, except per share amounts and market price

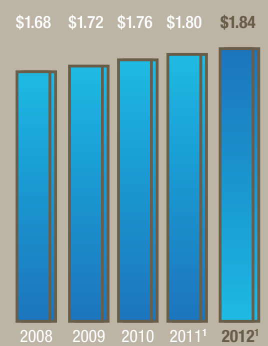
	2012	2011
Operating revenues	**$ 3,922**	$ 2,338
Net income attributable to AGL Resources Inc.	**$ 271**	$ 172
Earnings per common share attributable to AGL Resources Inc. common shareholders		
Basic	**$ 2.32**	$ 2.14
Diluted	**$ 2.31**	$ 2.12
Dividends declared per common share	**$ 1.74**	$ 1.90
Market capitalization (year-end)	**$ 4,711**	$ 4,946
Market price (year-end, closing)	**$ 39.97**	$ 42.26
Total assets	**$ 14,141**	$13,913
Total shareholder return	**(1%)**	24%

Adjusted Diluted Earnings per share



(1) For a reconciliation of adjusted EPS (which excludes costs related to the Nicor merger and additional accrual for the Nicor Gas PBR issue) to GAAP EPS, see our non-GAAP reconciliation section included within this report.

Indicated Annual Dividend per share



(1) Indicated 2011 and 2012 dividend rate. As a result of the Nicor merger, AGL Resources shareholders of record as of the close of business on December 8, 2011, received a pro rata dividend of $.0.0989 for the stub period accruing from November 19, 2011 for a total dividend of $1.90. This same $0.0989 would have been added to the $1.74 dividends paid in 2012 if it were not for the Nicor merger.

To Our Shareholders

John W. Somerhalder II

Chairman, President and Chief Executive Officer

In 2012, we performed well operationally against our objectives of prudent capital investment, safety and reliability. However, due primarily to record warm weather across much of the country and continued low natural gas price volatility, the company's financial performance did not meet our expectations. Temperatures were 14% warmer in Illinois and 26% warmer in Georgia compared to normal, and as a result, our pre-tax earnings were $33 million lower than our expectations across our distribution and retail businesses. We also continued to experience the impacts of ongoing low natural gas price volatility, which created challenges for some of our non-utility businesses. These factors and their impact on our stock price resulted in a 1% loss in total shareholder return for the year.

Much of our focus in 2012 was on the integration of the recently acquired Nicor business into the AGL Resources portfolio of companies. We made excellent progress and achieved significant cost savings by deploying our shared services model across a broader customer base. While the integration is largely complete from a functional perspective, we will continue to leverage our scale and experience to offer new services to our customers and create value for our shareholders.

FINANCIAL RESULTS

Our 2012 diluted GAAP earnings per share (EPS) were $2.31, compared to diluted GAAP EPS of $2.12 in 2011. Excluding expenses related to the Nicor merger, adjusted diluted EPS was $2.46 for 2012 compared to $2.92 for same the period in 2011. Our board of directors approved a 2% increase in the company's dividend, putting us on track for an indicated annual dividend rate of $1.88 per share for 2013. We expect to maintain our policy of increasing dividends and maintaining a payout ratio similar to our industry peers.

During the year, we continued to focus on maintaining strong, investment-grade credit ratings and a solid balance sheet. We deployed more than $780 million of capital investments throughout the year, with about 85% related to investment in our regulated utility business. More than 40% of our total utility capital expenditures were invested in support of our regulatory infrastructure programs, significantly minimizing the time between investment and regulatory recovery of those expenditures.

SIGNIFICANT ACHIEVEMENTS

DISTRIBUTION OPERATIONS

In our distribution operations segment, which operates seven natural gas utilities in seven states, we continue to focus on being a leader with regard to pipeline safety, maintenance and system enhancements. During 2012, we replaced more than 280 miles of aging pipeline infrastructure across our footprint. The proper maintenance and operation of our distribution system is paramount to the health of our company, and we will continue to invest in these areas.

For example, in 2012 our Virginia Natural Gas utility received approval for an accelerated infrastructure replacement program. The five-year program will enable us to spend up to $105 million on system enhancements. We also have filed the Integrated Vintage Plastic Replacement Program, a new program under Atlanta Gas Light's Strategic Infrastructure Development and Enhancement (STRIDE) program. This new program would replace aging plastic pipe with proposed capital investment of $275 million over the next three to four years. We anticipate receiving a ruling from the Georgia Public Service Commission in mid-2013.

We also achieved success in extending our system and promoting the use of natural gas in several new communities, particularly in Florida and Virginia. Natural gas prices have remained low for several years and, with the addition of domestically produced shale gas, we can expect abundant supplies in the years to come. As a result, current natural gas prices compare very favorably to other energy sources such as electricity and heating oil. These fundamentals work to our advantage as we work to attract new customers and retain existing customers.

We managed an excellent recovery effort in the wake of Superstorm Sandy. On our system in New Jersey, we performed more than 8,000 meter assessments, and we replaced or restored nearly 1,500 meters system-wide. Further, we deployed nearly 60 employees for mutual aid to support neighboring utilities in their restoration efforts.

We continue to promote the use of alternative fuels, such as compressed natural gas (CNG), across our service territories. In 2012, Atlanta Gas Light executed agreements with the City of Atlanta and three commercial operators to open five new CNG fueling stations throughout Georgia. We remain committed to the deployment of new technologies that promote the use of a clean-burning, abundant domestic resource across our service territories, and we will look to partner with a variety of constituencies in our communities to achieve these goals.

RETAIL OPERATIONS

Our retail businesses continued their solid, stable performance in 2012. At SouthStar, which primarily serves customers in Georgia, we remain the market share leader, a position we have held since the natural gas market deregulated over a decade ago. With Georgia experiencing the warmest weather on record in 2012, we successfully utilized a variety of asset management tools to offset lower customer usage and to optimize the commercial value of our storage and transportation assets.

We also focused efforts on integrating Nicor's retail services businesses in 2012. The stage is set to roll out many of the warranty and protection products across the legacy AGL Resources footprint in 2013. Further, in early 2013 we acquired the resource services business previously owned by NiSource. This business provides home warranty solutions such as appliance repair and line protection services and complements our existing retail services business. We viewed this as an opportunity to essentially double the size of that business and to gain scale in a cost effective manner. We expect the transaction to be accretive to earnings in 2013.

WHOLESALE SERVICES

Our wholesale services business remained challenged in 2012 on a GAAP-reported earnings basis, due primarily to low natural gas price volatility. However, the wholesale business created economic value in 2012 that we expect to realize in 2013. The business continues to be extremely important in managing many of our utility assets and has returned more than $200 million to customers under our asset management agreements over the last decade. We have structured our wholesale business as a low-risk energy marketer focused on serving our affiliate utilities, other utility companies, power generators and producers. Though the wholesale services business is delivering lower earnings, consistent with our expectations in a low volatility environment, it provides us an option on higher earnings under improving wholesale market conditions and periods of greater volatility.

At AGL Resources, we are working hard to deliver natural gas to our customers whether for home use, business, industrial applications or clean-burning natural gas vehicles.

MIDSTREAM OPERATIONS

We completed construction of two natural gas storage facilities in 2012 – Central Valley Gas Storage and the second cavern of our Golden Triangle Storage facility. Our construction of new facilities is now complete and we anticipate capital expenditures related to the storage business to decrease in 2013 and the coming years. Our midstream operations business remains challenged due to low natural gas price volatility and narrow seasonal storage spreads, the same general factors that also have impacted our wholesale services business. Overall the market for storage remains weak, but we continue to focus on ways to optimize the value of our available capacity while not committing to long-term contracts at historically low prices. We remain optimistic that the market for storage will recover long-term as natural gas supply growth moderates and demand continues to grow resulting in a more balanced market.

CARGO SHIPPING

We acquired our cargo shipping business as part of our acquisition of Nicor. Tropical Shipping has provided containerized cargo transportation services in the Bahamas and Caribbean regions for 50 years. Although this business has been challenged recently by the weak economic conditions that have persisted in those regions, we saw some modest improvement in 2012. Market share and vessel utilization have shown signs of improvement, and we will continue to focus our efforts in 2013 on improving the overall profitability of this business segment.

We will remain focused on efficient operations across all of our businesses, including offsetting natural inflationary pressures by spreading costs across a broader customer base and sizing our operations to properly reflect market challenges.

NATURAL GAS MARKET FUNDAMENTALS

Production of domestic natural gas from shale formations has increased from just under 2 trillion cubic feet (Tcf) in 2007 to almost 9 Tcf today. This bodes well for our industry and for low natural gas prices in the years to come. Currently, natural gas supplies nearly one-fourth of all energy used in the United States and that amount should increase in the future, thanks to natural gas being a low-cost, low-carbon fuel. In fact, consumption of natural gas is expected to increase 11% by 2030, according to the U.S. Department of Energy.

At AGL Resources, we are working hard to deliver natural gas to our customers whether for home use, business, industrial applications or clean-burning natural gas vehicles. Our regulated utilities serve 4.5 million customers and we operate 80,000 miles of distribution pipeline across seven states. Our retail, wholesale and midstream businesses round out our robust portfolio of natural gas assets, which can effectively meet the needs of a wide range of customers. We remain well-positioned to take advantage of our country's increasing reliance on natural gas.

PRIORITIES FOR 2013

Our overall business strategy for 2013 is consistent with the direction we have taken the company over the past decade. We will remain focused on efficient operations across all of our businesses, including offsetting natural inflationary pressures by spreading costs across a broader customer base and sizing our operations to properly reflect market challenges. Several of our specific business objectives are detailed as follows:

- **Distribution operations:** Invest necessary capital to enhance and maintain safety and reliability; remain a low-cost leader within the industry; opportunistically expand system and capitalize on potential customer conversions.
- **Retail operations:** Maintain margins in Georgia and Illinois while continuing to expand into other profitable retail markets; integrate our new retail services business and expand our overall market reach.
- **Wholesale services:** Maximize strong storage and transportation rollout value created in 2012; effectively perform on existing asset management agreements and expand customer base; bring cost structure in line with market fundamentals.
- **Midstream operations:** Optimize storage portfolio, including expiring contracts; pursue land-based LNG transportation opportunities.
- **Cargo Shipping:** Increase vessel utilization and improve margin per Twenty-foot Equivalent Unit; prudently deploy capital investment and diligently manage operating costs.

We provided 2013 earnings guidance in the range of $2.50 to $2.70 per diluted share, and an additional range of $2.40 to $2.50 per diluted share, excluding our wholesale services segment. Our wholesale services business often creates some volatility in our earnings due to the accounting and timing mismatch between when economic earnings are generated and GAAP earnings reported. We believe this more granular measure should allow our investors to better track our business performance as we progress through the year without this quarterly volatility clouding our results.

On behalf of the more than 6,000 employees of AGL Resources, we thank you for your investment in our company. We remain focused on creating value for our shareholders and building on our solid foundation as one of the nation's leading natural gas providers.

Sincerely,

John W. Somerhalder II
Chairman, President and
Chief Executive Officer
February 28, 2013

Board of Directors

Sandra N. Bane [1,2]
Retired Audit Partner, KPMG, LLP
Director since 2008

Thomas D. Bell, Jr. [2,4]
Chairman of Mesa Capital Partners, LLC
Director since 2004

Norman R. Bobins [1,2]
President and CEO of Norman Bobins Consulting, LLC
Director since 2011

Charles R. Crisp [2,4]
Retired CEO and Director of Coral Energy, a subsidiary of Shell Oil Company
Director since 2003

Brenda J. Gaines [1,5]
Retired President and CEO of Diners Club North America, a division of Citigroup
Director since 2011

Arthur E. Johnson [3*,4,5]
Lead Director of the Board of Directors of AGL Resources and Retired Senior Vice President, Lockheed Martin Corporation
Director since 2002

Wyck A. Knox, Jr. [1,5]
Retired Partner in, Kilpatrick, Townsend & Stockton, LLP
Director since 1998

Dennis M. Love [1,3,5*]
President and CEO, Printpack, Inc.
Director since 1999

Charles H. "Pete" McTier [1,5]
Retired President of the Robert W. Woodruff Foundation, the Joseph B. Whitehead Foundation, the Lettie Pate Evans Foundation and the Lettie Pate Whitehead Foundation
Director since 2006

Dean R. O'Hare [1,5]
Retired Chairman and Chief Executive Officer, The Chubb Corporation
Director since 2005

Armando J. Olivera [2,4]
Retired President and CEO of Florida Power & Light Company
Director since 2011

John E. Rau [3,4,5]
President and CEO of Miami Corporation
Director since 2011

James A. Rubright [2,3,4*]
Chairman and CEO, RockTenn Company
Director since 2001

John W. Somerhalder II [3,4]
Chairman, President and Chief Executive Officer
Director since 2006

Bettina M. Whyte [2*,3,4]
Managing Director and Senior Advisor, Alvarez & Marsal Holdings, LLC
Director since 2004

Henry C. Wolf [1*,2,3]
Retired Vice Chairman and Chief Financial Officer of Norfolk Southern Corporation
Director since 2004

* Committee Chair
1 Audit
2 Compensation and Management Development
3 Executive
4 Finance and Risk Management
5 Nominating, Governance and Corporate Responsibility

Executive Officers

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

Andrew W. Evans
Executive Vice President and Chief Financial Officer

Henry P. Linginfelter
Executive Vice President, Distribution Operations

Paul R. Shlanta
Executive Vice President, General Counsel and Chief Ethics and Compliance Officer

Peter I. Tumminello
Executive Vice President, Wholesale Services, and President, Sequent Energy Management

Melanie M. Platt
Executive Vice President, Chief People Officer and President, AGL Resources Foundation

Shareholder Information

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

Stock Exchange Listing
Our common stock is traded on the New York Stock Exchange under the symbol "GAS" and quoted in The Wall Street Journal as "AGL Res."

Transfer Agent and Registrar
Wells Fargo serves as our transfer agent and registrar and can help with a variety of stock-related matters, including name and address changes; transfer of stock ownership; lost certificates; and Form 1099s.

Inquiries may be directed to: Wells Fargo Shareowner Services, P.O. Box 64874, St. Paul, MN 55164-0874; toll-free 800-468-9716; website: wellsfargo.com/shareownerservices.

Available Informatiom
A copy of this Annual Report, as well as our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, other reports that we file with or furnish to the Securities and Exchange Commission (SEC) and our recent news releases are available free of charge at our website, aglresources.com, as soon as reasonably practicable. The information contained on our website should not be considered part of this document and is not incorporated by reference.

Our Annual Report on Form 10-K includes the certifications of our chief executive officer and chief financial officer required by Sections 302 and 906 of the Sarbanes-Oxley Act of 2002. Additionally, we have filed the most recent annual CEO certification as required by Section 303A. 12(a) of the New York Stock Exchange Listed Company Manual pursuant to which our CEO certified to the NYSE that he was not aware of any violation by AGL Resources of the NYSE's corporate governance listing standards.

Our corporate governance guidelines; our code of ethics for the CEO and senior financial officers; our code of conduct and ethics; and the charters of our Board committees also are available on our website.

The above information and any exhibit to our 2012 Form 10-K also will be furnished free of charge upon written request to our Investor Relations department at: Sarah Stashak, Director, Investor Relations, AGL Resources, Ten Peachtree Place, N.E., Atlanta, GA 30309; 404-584-4000; sstashak@aglresources.com.

Institutional Investor Inquiries
Institutional investors and securities analysts should direct inquiries to: Sarah Stashak, Director, Investor Relations, AGL Resources, Ten Peachtree Place, N.E., Atlanta, GA 30309; 404-584-4000; sstashak@aglresources.com.

GAAP Reconciliation

	Year Ended December 31, 2012	2011	2010
Diluted earnings per share - as reported	$2.31	$2.12	$3.00
Additional accrual for Nicor Gas PBR issue	0.04	0.00	0.00
Transaction costs of Nicor merger	0.11	0.80	0.05
Diluted earnings per share - as adjusted	$2.46	$2.92	$3.05

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2012

OR

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

For the transition period from to

Commission File Number 1-14174

AGL RESOURCES INC.

(Exact name of registrant as specified in its charter)

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

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

Title of 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 ☑ No ☐

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

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

Indicate by check mark 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 ☑ 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 ☑ 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 ☑

The aggregate market value of the registrant's common stock held by non-affiliates of the registrant (based on the closing sale price on June 29, 2012, as reported by the New York Stock Exchange), was $4,553,236,484.

The number of shares of the registrant's common stock outstanding as of January 31, 2013 was 117,876,484.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the Proxy Statement for the 2013 Annual Meeting of Shareholders (Proxy Statement) to be held on April 30, 2013, are incorporated by reference in Part III.

TABLE OF CONTENTS

GLOSSARY OF KEY TERMS

AGL Capital	AGL Capital Corporation
AGL Credit Facility	$1.3 billion credit agreement entered into by AGL Capital to support the AGL Capital commercial paper program
AGL Resources	AGL Resources Inc., together with its consolidated subsidiaries
Atlanta Gas Light	Atlanta Gas Light Company
Bcf	Billion cubic feet
Bridge Facility	Credit agreement entered into by AGL Capital Corporation to finance a portion of the Nicor merger
Central Valley	Central Valley Gas Storage, LLC
Chattanooga Gas	Chattanooga Gas Company
Chicago Hub	A venture of Nicor Gas, which provides natural gas storage and transmission-related services to marketers and gas distribution companies
California Commission	California Public Utilities Commission, the state regulatory agency for Central Valley
EBIT	Earnings before interest and taxes, a non-GAAP measure that includes operating income and other income and excludes financing costs, including interest on debt and income tax expense
ERC	Environmental remediation costs associated with our distribution operations segment that 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
Georgia Natural Gas	The trade name under which SouthStar does business in Georgia
Golden Triangle Storage	Golden Triangle Storage, Inc.
Hampton Roads	Virginia Natural Gas' pipeline project that 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 through March when natural gas usage and operating revenues are generally higher because weather is colder
Henry Hub	A major interconnection point of natural gas pipelines in Erath, Louisiana where NYMEX natural gas future contracts are priced
Horizon Pipeline	Horizon Pipeline Company, LLC
Illinois Commission	Illinois Commerce Commission, the state regulatory agency for Nicor Gas
Jefferson Island	Jefferson Island Storage & Hub, LLC
LIBOR	London Inter-Bank Offered Rate
LIFO	Last-in, first-out, an accounting method used to account for inventory
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
Merger Agreement	Agreement and Plan of Merger, dated December 6, 2010, as amended, by and among the Company, Nicor, Apollo Acquisition Corp, an Illinois corporation and wholly owned subsidiary of the Company, and Ottawa Acquisition LLC, an Illinois Limited Liability Company and a wholly owned subsidiary of the Company
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 acquisition completed in December 2011 and former holding company of Nicor Gas
Nicor Advanced Energy	Prairie Point Energy, LLC, doing business as Nicor Advanced Energy
Nicor Gas	Northern Illinois Gas Company, doing business as Nicor Gas Company
Nicor Gas Credit Facility	$700 million credit facility entered into by Nicor Gas to support its commercial paper program
Nicor Services	Nicor Energy Services Company
Nicor Solutions	Nicor Solutions, LLC
NUI	NUI Corporation - acquired 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 goods sold and revenue tax expense
OTC	Over-the-counter
Pad gas	Volumes of non-working natural gas used to maintain the operational integrity of the natural gas storage facility, also known as base gas
PBR	Performance-based rate, a regulatory plan at Nicor Gas that provided economic incentives based on natural gas cost performance. The plan terminated in 2003
PGA	Purchased Gas Adjustment
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.
Seven Seas	Seven Seas Insurance Company, Inc.
SNG	Substitute natural gas, a synthetic form of gas manufactured from coal
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
TEU	Twenty-foot equivalent unit, a measure of volume in containerized shipping equal to one 20-foot-long container
Triton	Triton Container Investments LLC, a cargo container leasing company in which we have an investment
Tropical Shipping	Tropical Shipping and Construction Company Limited, a Cayman Islands company. A wholly owned business and a carrier of containerized freight in the Bahamas and the Caribbean region
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 United States 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 also may 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 of which are 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 agency approvals, development project delays, adequacy of supply of diversified vendors and unexpected changes in project costs, including the cost of funds to finance these projects; limits on pipeline capacity; the impact of acquisitions and divestitures; our ability to successfully fully integrate operations that we have or may acquire or develop in the future; direct or indirect effects on our business, financial condition or liquidity resulting from any change in our credit ratings or in the credit ratings of our counterparties or competitors; interest rate fluctuations; financial market conditions, including disruptions in the capital markets and lending environment; general economic conditions; uncertainties about environmental issues and the related impact of such issues, including our environmental remediation plans; 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 and on our cargo shipping business; acts of war or terrorism; the outcome of litigation; and other factors discussed elsewhere herein and in our other filings with the SEC.

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 our actual 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 United States federal securities law.

PART I

ITEM 1. BUSINESS

Unless the context requires otherwise, references to “we,” “us,” “our” and the “company” are intended to mean AGL Resources Inc. together with its consolidated subsidiaries. The operations and businesses described in this filing are owned and operated, and management services provided, by distinct direct and indirect subsidiaries of AGL Resources. AGL Resources Inc. was organized and incorporated in 1995 under the laws of the State of Georgia.

Nature of Our Business

AGL Resources Inc. is an energy services holding company. Our primary business is the distribution of natural gas in seven states - Illinois, Georgia, Virginia, New Jersey, Florida, Tennessee and Maryland - through our seven natural gas distribution utilities. At December 31, 2012, our utilities served approximately 4.5 million end-use customers.

We also are involved in several other businesses that are primarily related and complementary to our primary business. Our retail operations segment serves more than one million retail customers and markets natural gas and related home services to end-use customers in Georgia, Illinois, Indiana, Ohio, Florida and New York. Our wholesale services segment engages in natural gas storage and gas pipeline arbitrage and related activities. Additionally, it provides natural gas asset management and/or related logistics services for each of our utilities, as well as for non-affiliated companies. Our midstream operations segment provides natural gas storage arbitrage and related activities and engages in the development and operation of high-deliverability natural gas storage assets. We also are involved in the shipping industry through our cargo shipping segment, which owns and operates Tropical Shipping, one of the largest containerized cargo carriers serving the Bahamas and the Caribbean.

Our operating segments consist of the following five operating and reporting segments - distribution operations, retail operations, wholesale services, midstream operations, cargo shipping and one non-operating segment - other. These segments are consistent with how management views and manages our businesses. 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 13 to our consolidated financial statements under Item 8 herein.

Merger with Nicor

On December 9, 2011, we closed our merger with Nicor and created a combined company with increased scale and scope in the distribution, storage and transportation of natural gas. As a result, we are currently the nation’s largest natural gas distribution company based on customer count. The effects of Nicor’s results of operations and financial condition are reflected for the twelve months ended December 31, 2012, while our 2011 results include activity from December 10, 2011 through December 31, 2011. See Note 3 to our consolidated financial statements under Item 8 herein for more information on the impacts of the Nicor merger on our business.

Distribution Operations

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

Utility	State	Number of customers (in thousands)	Approximate miles of pipe
Nicor Gas	Illinois	2,188	34,000
Atlanta Gas Light	Georgia	1,541	32,300
Virginia Natural Gas	Virginia	281	5,500
Elizabethtown Gas	New Jersey	277	3,150
Florida City Gas	Florida	104	3,450
Chattanooga Gas	Tennessee	62	1,600
Elkton Gas	Maryland	6	100
Total		4,459	80,100

Our primary focus in our distribution operations business is the safe and reliable delivery of natural gas to our end-users. In integrating Nicor Gas into our existing distribution operations, we focused on the standardization of operational processes and continue to focus on delivering superior customer service.

We experienced a 0.1% increase in our total number of customers in 2012, consistent with the 0.1% increase in 2011, excluding Nicor Gas. The customer count of Nicor Gas remained flat in 2012, compared to the year ended 2011. We anticipate customer growth trends to improve slightly in 2013 compared to 2012.

Competition and Customer Demand

All of our utilities face competition from other energy products. Our principal competitors are 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.

We continue to develop and grow 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.

The natural gas related 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. We expect to continue this focus for the foreseeable future. We have also worked with the Illinois Commission, the Virginia Commission, the Tennessee Authority 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.

Sources of Natural Gas Supply

Procurement plans for natural gas supply and transportation to serve our regulated utility customers are reviewed and approved by our state utility commissions. Accordingly, we purchase natural gas supplies in the open market by contracting with producers and marketers. We also contract for transportation and storage services from interstate pipelines that are regulated by the FERC. When firm pipeline services are temporarily not needed, we may release the services in the secondary market under FERC-approved capacity release provisions or utilize asset management arrangements, reducing the cost of natural gas charged to customers for most of our utilities. Peak-use requirements are met through utilization of company-owned storage facilities, pipeline transportation capacity, purchased storage services, peaking facilities and other supply sources, arranged by either our transportation customers or us. We have been able to obtain sufficient supplies of natural gas to meet customer requirements. We believe natural gas supply and pipeline capacity will be sufficiently available to meet market demands in the foreseeable future.

Transportation Our utilities use firm pipeline entitlements, storage services, and/or peaking capacity contracted with interstate capacity providers to serve the firm gas supply needs of our customers. In addition, Nicor Gas, Atlanta Gas Light, Chattanooga Gas, Elizabethtown Gas and Virginia Natural Gas operate on-system LNG facilities, underground natural gas storage fields and/or propane / air plants to meet the gas supply and deliverability requirements of their customers in the winter period. Generally, we work to build a portfolio of year-round firm transportation, seasonal storage and short-duration peaking services that will meet the needs of our customers under severe weather conditions with adequate operational flexibility to reliably manage the variability inherent in servicing customers using natural gas for space heating. We believe that including seasonal storage and peaking services in this portfolio is more efficient and cost effective compared to reserving firm pipeline capacity rights all year for a limited number of cold winter days.

Typically, our firm contracts range in duration from 3 to 10 years. We work to stagger terms to maintain our ability to adjust the overall portfolio to meet changing market conditions. Our utilities have contracted for capacity that is predominately sourced from producing areas in the midcontinent and gulf coast regions and they continue to evaluate capacity options that will provide long-term access to reliable and affordable natural gas supply. We have and will continue to evaluate options to acquire capacity rights from shale gas being produced in close proximity to our service territories.

Given the number of agreements held by our utilities and the amount of capacity under contract, we make decisions as to the termination, extension or renegotiation of contracts every year. Slower demand associated with the weak economy and the recent warm winter season coupled with the growth in non-traditional supply basins have made the value assessment of capacity contracts more complex.

Supply Six of our utilities use asset management agreements with our wholly owned subsidiary, Sequent, with the primary goal of reducing our utility customers' gas cost recovery rates through payments to the utilities by Sequent (for Atlanta Gas Light these payments are controlled by the Georgia Commission and utilized for infrastructure improvements and to fund heating assistance programs, rather than a reduction to gas cost recovery rates). Under these asset management agreements, Sequent supplies natural gas to the utility and markets excess capacity to improve the overall cost of supplying gas to the utility customers. At this time, the utilities purchase most of their gas from Sequent. The purchase agreements obligate Sequent to provide firm gas to our utilities. However, these utilities maintain the right and ability to make their own supply purchases. This right allows our utilities to make long-term supply arrangements if they believe it is in the best interest of their customers.

The agreements with Sequent have one of the following: an annual minimum guarantee within a profit sharing structure, a profit sharing structure without any annual minimum guarantee or a fixed fee. Under these agreements, Sequent made payments of $15 million to our utilities in 2012. From the inception of these agreements in 2001 through 2012, Sequent has made sharing payments under these agreements totaling $207 million. The following table provides payments made by Sequent to our utilities under these agreements during the last three years.

	Total amount received			
In millions	**2012**	**2011**	**2010**	**Expiration Date**
Atlanta Gas Light	$5	$9	$4	March 2017
Virginia Natural Gas	3	9	5	March 2016
Elizabethtown Gas	5	9	10	March 2014
Florida City Gas	1	2	1	March 2014
Chattanooga Gas	1	3	4	March 2014
Total	$15	$32	$24	

In March 2012, the Georgia Commission authorized the renewal of the asset management agreement between Atlanta Gas Light and Sequent. The renewed five-year agreement requires Sequent to pay minimum annual fees of $3 million and includes a slight increase in sharing levels associated with storage inventory activity.

Nicor Gas is our only utility that has not entered into an affiliated asset management agreement with Sequent. Accordingly, it purchases its gas supply under firm contracts from a number of different suppliers, typically using the North American Energy Standards Board standard contract. The transactions conducted under the contracts include firm base load supplies, firm daily swing supplies and spot market purchases. The agreements often include some form of index pricing, but purchases may also be made using negotiated pricing. A majority of the purchases specify the pipeline receipt point associated with capacity held by Nicor Gas, but some purchases are made on a city-gate delivered basis.

Utility Regulation and Rate Design

Rate Structures Our utilities operate subject to regulations and oversight of the state regulatory agencies in each of the states served by our utilities 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 the utility plant in service, working capital and certain other assets, less accumulated depreciation on the utility plant in service and net deferred income tax liabilities, and may include certain other additions or deductions.

The natural gas market for Atlanta Gas Light 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; and
- 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. We have various mechanisms, such as weather normalization at some of our utilities, which limit our exposure to weather changes within typical ranges in these utilities’ respective service areas.

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 all of the costs prudently 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. However, Atlanta Gas Light does maintain inventory for the Marketers in Georgia and recovers the cost of this gas through recovery mechanisms approved by the Georgia Commission. In addition to natural gas recovery mechanisms, we have other cost recovery mechanisms, such as regulatory riders, which vary by utility but allow us to recover certain costs, such as those related to environmental remediation and energy efficiency plans.

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. Three 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.

The following table provides regulatory information for our six largest utilities.

	Nicor Gas (9)	**Atlanta Gas Light**	**Virginia Natural Gas**	**Elizabethtown Gas**	**Florida City Gas**	**Chattanooga Gas**
Authorized return on rate base (1)	8.09%	8.10%	7.38%	7.64%	7.36%	7.41%
Estimated 2012 return on rate base (2)	6.24%	8.71%	7.74%	8.51%	6.07%	7.99%
Authorized return on equity (1)	10.17%	10.75%	10.00%	10.30%	11.25%	10.05%
Estimated 2012 return on equity (2)	6.50%	11.94%	10.79%	12.11%	10.42%	11.29%
Authorized rate base % of equity (1)	51.1%	51.0%	45.4%	47.9%	36.8%	46.1%
Rate base included in 2012 return on equity (in millions) (2)	$1,418	$2,045	$577	$478	$166	$90
Weather normalization (3)			✓	✓		✓
Decoupled or straight-fixed-variable rates (4)		✓				✓
Regulatory infrastructure program rates (5)		✓	✓	✓		
Bad debt rider (6)	✓		✓			✓
Synergy sharing policy (7)		✓				
Energy efficiency plan (8)	✓			✓	✓	✓
Last decision on change in rates	Oct. 2009	Oct. 2010	Dec. 2011	Dec. 2009	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, 2012.
(2) Estimates based on principles consistent with utility ratemaking in each jurisdiction. Rate base includes investments in regulatory infrastructure programs.
(3) 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. Based on the structure of Atlanta Gas Light, it does not need or utilize a weather normalization recovery mechanism.
(4) 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. Virginia Natural Gas filed for approval of a decoupled rate design in December 2012.
(5) Includes programs that update or expand our distribution systems and liquefied natural gas facilities.
(6) Involves the recovery (refund) of the amount of bad debt expense over (under) an established benchmark expense. Virginia Natural Gas and Chattanooga Gas recover the gas portion of bad debt expense through PGA mechanisms.
(7) Involves the recovery of 50% of net synergy savings achieved on future acquisitions.
(8) Includes the recovery of costs associated with plans to achieve specified energy savings goals.
(9) In connection with the Nicor merger, we agreed to (i) not initiate a rate proceeding for Nicor Gas that would increase base rates prior to December 2014, (ii) maintain 2,070 full-time equivalent employees involved in the operation of Nicor Gas for a period of three years and (iii) maintain the personnel numbers in specific areas of safety oversight of the Nicor Gas system for a period of five years.

Nicor Gas On January 1, 2000, Nicor Gas instituted a PBR plan for natural gas costs, which was terminated effective January 1, 2003. Under the PBR plan, Nicor Gas' total gas supply costs were compared to a market-sensitive benchmark. Savings and losses relative to the benchmark were determined annually and shared equally with sales customers.

In February 2012, we committed to a stipulated resolution of issues with the Illinois Commission, which would include crediting Nicor Gas customers $64 million. The stipulated resolution does not constitute an admission of fault, is not final and is subject to review and approval by the Illinois Commission. The Citizens Utility Board (CUB) and the Illinois Attorney General's Office (IAGO) are not parties to this stipulated resolution and continue to pursue their claims in this proceeding, requesting refunds of $305 million and $255 million, respectively. On November 5, 2012, the Administrative Law Judges issued a proposed order that Nicor Gas refund $72 million to ratepayers. We have increased our accrual by $8 million for a total of $72 million as a result of these developments and its effect on the estimated liability. The PBR plan is currently under review by the Illinois Commission and must be acted upon by them before becoming a final decision. We do not agree with the additional $8 million proposed by the Administrative Law Judges and will consider all legal recourse available should the Illinois Commission authorize a refund greater than the $64 million stipulation amount between Nicor Gas and the staff of the Illinois Commission. For more information on the PBR plan, see Note 11 to our consolidated financial statements under Item 8 herein.

Virginia Natural Gas In accordance with the State of Virginia Natural Gas Conservation and Ratemaking Efficiency Act (CARE), Virginia Natural Gas filed for approval of its CARE plan with the Virginia Commission on December 3, 2012. This plan includes a decoupling mechanism and authority to record accounting entries associated with such a mechanism. Our CARE plan has two principal components: (i) an Energy Conservation Plan component consisting of four cost-effective conservation and energy efficiency initiatives or programs plus a Community Outreach and Customer Education program; and (ii) a natural gas decoupling mechanism, Revenue Normalization Adjustment component and a designated Rider D, which provides for a sales adjustment consistent with the Virginia code. Our filing requests that the CARE plan become effective June 1, 2013 for a three-year period with a total cost of $5 million.

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.

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 them. These costs are primarily recovered through rate riders.

See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Critical Accounting Policies and Estimates," for additional information about our environmental remediation liabilities. Also see Note 11 to our consolidated financial statements under Item 8, "Financial Statements and Supplementary Data" for information on our environmental remediation efforts.

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 to us and our customers, provide an appropriate return on invested capital and ensure the safety, reliability and integrity of our utility infrastructure. The following table and discussions provide updates on some of our larger capital projects in our distribution operations segment. These programs update or expand our distribution systems to improve system reliability and meet operational flexibility and growth. Our anticipated expenditures for these programs in 2013 are discussed in "Liquidity and Capital Resources" under the caption "Cash Flows from Financing Activities."

Dollars in millions	**Utility**	**2012 expenditures**	**Expenditures since project inception**	**Miles of pipe replaced**	**Year project began**	**Anticipated year of completion**
STRIDE program						
Pipeline replacement program	Atlanta Gas Light	$129	$697	2,625	1998	2013
Integrated System Reinforcement Program	Atlanta Gas Light	83	224	n/a	2009	2013
Integrated Customer Growth Program	Atlanta Gas Light	17	29	n/a	2010	2013
Enhanced infrastructure program (1)	Elizabethtown Gas	18	108	109	2009	2012
Accelerated infrastructure program	Virginia Natural Gas	16	16	42	2012	2017
Total		$263	$1,074	2,776		

(1) In July 2012, we filed for a five-year extension of this program.

Atlanta Gas Light Our STRIDE program comprises the ongoing pipeline replacement program, the Integrated System Reinforcement Program (i-SRP) and the Integrated Customer Growth Program (i-CGP). These pipeline replacement programs are used to update and expand distribution systems and liquefied natural gas facilities, improve system reliability and meet operations flexibility and growth. The purpose of i-SRP is to upgrade our distribution system and liquefied natural gas facilities in Georgia, improve our peak-day system reliability and operational flexibility, and create a platform to meet long-term forecasted growth. The i-CGP authorizes Atlanta Gas Light to extend its pipeline facilities to serve customers in areas without pipeline access and create new economic development opportunities in Georgia. The STRIDE program requires us to file an updated ten-year forecast of infrastructure requirements under i-SRP along with a new construction plan every three years for review and approval by the Georgia Commission. The deadline for filing our next STRIDE construction plan was extended by the Georgia Commission to August 2013 to allow additional time to complete the installation of the initial i-SRP construction program.

On November 21, 2012 we filed the Integrated Vintage Plastic Replacement Program (i-VPR) with the Georgia Commission, as a new component of STRIDE. If approved, this program would replace aging plastic pipe that was installed primarily in the mid-1960's to the early 1980's. We have identified approximately 3,300 miles of vintage plastic mains in our system that potentially should be considered for expedited replacement over the next 15 - 20 years as it reaches the end of its useful life. However, the initial request to the Georgia Commission is to replace approximately 756 miles over the next three to four years. The estimated cost of the first tranche of pipe to be replaced under construction activity under i-VPR is $275 million. A decision on how to proceed with the replacement of vintage plastic pipes is expected later in 2013.

Virginia Natural Gas On January 31, 2012, Virginia Natural Gas filed SAVE, an accelerated infrastructure replacement program, with the Virginia Commission, which involves replacing aging infrastructure as prioritized through Virginia Natural Gas' distribution integrity management program. SAVE was filed in accordance with a Virginia statute providing a regulatory cost recovery mechanism to recover the costs associated with certain infrastructure replacement programs. The Virginia Commission approved SAVE on June 25, 2012, for a five-year period which includes a maximum allowance for capital expenditure of $25 million per year, not to exceed $105 million in total. SAVE is subject to annual review by the

Virginia Commission. We began recovering costs based on this program through a rate rider that became effective August 1, 2012.

Elizabethtown Gas The New Jersey BPU-approved accelerated enhanced infrastructure program was created in response to the New Jersey Governor's request for utilities to assist in the economic recovery by increasing infrastructure investments. On May 16, 2011, the New Jersey BPU approved Elizabethtown Gas' request to spend an additional $40 million under this program before the end of 2012. Costs associated with the investment in this program are recovered through periodic adjustments to base rates. In July 2012, we filed for an extension of the program to add $135 million in additional spend over five years. A ruling is expected from the New Jersey BPU in the first half of 2013.

Retail Operations

The companies in our retail operations segment market natural gas and related home services, such as appliance repair and gas and electric line protection plans. This segment also offers products that provide protection and comfort services as well as natural gas price risk and utility bill management services. Companies within our retail operations segment include SouthStar, Nicor Advanced Energy, Nicor Solutions and Nicor Services.

Our retail operations businesses generate earnings through the sale of natural gas to residential, commercial and industrial customers, primarily in Georgia and Illinois where we capture spreads between wholesale and retail natural gas prices. We offer our customers energy-related products that provide for natural gas price stability and utility bill management. These products mitigate and/or eliminate the risks to customers of colder-than-normal weather and/or changes in natural gas prices. We charge a fee or premium for these services.

We also collect monthly service fees and customer late payment fees. We evaluate 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.

Through our commercial operations, we optimize storage and transportation assets and effectively manage commodity risk, which enables SouthStar to maintain competitive retail prices and operating margin. SouthStar, a joint venture currently owned 85% by us and 15% by Piedmont, markets natural gas and related services to retail customers on an unregulated basis, primarily in Georgia under the trade name Georgia Natural Gas. SouthStar also serves retail customers primarily in Ohio, Florida and New York. We have no contractual rights to acquire Piedmont's remaining 15% ownership interest.

SouthStar is governed by an executive committee, which comprises six members, three representatives from AGL Resources and three representatives 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" under the caption "Natural Gas Price Risk."

Nicor Solutions offers its residential and small commercial customers, primarily in the Nicor Gas service territory, energy-related products that provide for natural gas price stability and utility bill management. These products mitigate and/or eliminate the risks to customers of colder-than-normal weather and/or changes in natural gas prices. Nicor Advanced Energy is certified by the Illinois Commission as an Alternate Gas Supplier, authorizing it to be a non-utility marketer of natural gas for residential and small commercial customers. Nicor Advanced Energy presently operates in northern Illinois, offering customers an alternative to the utility as its natural gas supplier.

Our retail operations businesses also provide protection solutions to customers through Nicor Services. Such services include a gas line repair plan and a heating, ventilation, and air conditioning repair and/or maintenance plan, whereby we, in return for a predetermined monthly amount collected from customers, provide repair and/or maintenance per the contracted terms. In addition, we also provide customers with move connection services for utilities. Currently, our retail operations businesses primarily provide warranty protection solutions to customers in Illinois, Indiana and Ohio under the Nicor National brand. We intend to expand this business in 2013 to include our service territories in Georgia, Virginia and Tennessee. We anticipate this expansion will provide growth opportunities in 2013 and beyond.

On January 31, 2013, Nicor Services acquired approximately 500,000 service plans and certain other assets of NiSource Inc.'s retail services business for approximately $120 million. We believe this acquisition will drive expansion in seven states and provide a platform for growth and continued expansion.

Competition Our retail operations business competes with other energy marketers to provide natural gas and related services to customers in Georgia, Illinois, Indiana, Ohio, New York and the Southeast region. In the Georgia market, SouthStar operates as Georgia Natural Gas and is the largest of eleven Marketers, with average customers of nearly 500,000 over the last three years and market share of approximately 32%.

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, our retail operations businesses face competition based on customer preferences for natural gas compared to other energy products, primarily electricity, and the comparative prices of those products. We continue to use a variety of targeted marketing programs to attract new customers and to retain existing customers.

Our retail operations businesses also experience price, convenience and service competition from other warranty and HVAC companies. These businesses also bear risk from potential changes in the regulatory environment. As a condition of the merger, Nicor Gas is no longer permitted to use its call center personnel to solicit its affiliates' products, most notably the warranty products.

Wholesale Services

Our wholesale services segment primarily consists of our wholly owned subsidiaries Sequent and Compass Energy (Compass). Sequent is involved in asset management and optimization, storage, transportation, producer and peaking services and wholesale marketing of natural gas across the United States and in Canada. Nicor Enerchange, which was integrated into Sequent as part of the Nicor merger, expands Sequent's wholesale marketing of natural gas supply services in the Midwest, enables Sequent to serve commercial and industrial customers in the Midwest primarily in the northern Illinois market area and manages Nicor Solutions' and Nicor Advanced Energy's product risks, including the purchase of natural gas supplies. In 2013, we anticipate that SouthStar will assume the product risks for Nicor Solutions and Nicor Advanced Energy. Compass provides natural gas supply and services to commercial, industrial and governmental customers primarily in Kentucky, Ohio, Pennsylvania, Virginia and West Virginia.

Wholesale services 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. Our logistical expertise enables us to provide our customers with natural gas from the major producing regions and market hubs in the United States and Canada and meet our delivery requirements and customer obligations at competitive prices by leveraging our portfolio of natural gas storage assets and contracted natural gas supply, transportation and storage capacity.

Wholesale services' portfolio of storage and transportation capacity enables us to generate additional operating margin by optimizing the contracted assets through the application of our wholesale market knowledge and risk management skills as 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. We seek to mitigate the commodity price and volatility risks and protect our operating margin through a variety of risk management and economic hedging activities.

Competition Wholesale services competes for asset management, long-term supply and seasonal peaking service contracts with other energy wholesalers, often through a competitive bidding process. We are able to price competitively by utilizing our portfolio of contracted storage and transportation assets and by renewing and adding new contracts at prevailing market rates. We will continue to broaden our market presence in sections of the United States and Canada where our portfolio of contracted storage and transportation assets provides us a competitive advantage, as well as continue our pursuit of additional opportunities with power generation companies located in the areas of the country in which we operate. We are also focused on building our fee-based services in part to have a source of operating margin that is less impacted by volatility in the marketplace.

Asset Management Transactions Our asset management customers include affiliated and non-affiliated 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 that exceed their actual requirements. We enter into structured agreements with these customers, whereby we, on behalf of the customers, optimize the transportation and storage capacity during periods when customers do not use it for their own needs. We may capture incremental operating margin through optimization, and either share margins with customers or pay them a fixed amount.

Transportation Transactions We enter into contracts for natural gas transportation capacity and participate in forward financial and related commodity transactions that manage the natural gas commodity and transportation costs in an attempt to achieve the lowest cost to serve our various markets. We seek to optimize this process on a daily basis as market conditions change by evaluating all the natural gas supplies, transportation alternatives and markets to which we have access and identifying the lowest-cost alternatives to serve our markets. This enables us to capture geographic pricing differences across these various markets as delivered natural gas prices change.

As we execute transactions to secure transportation capacity, we often enter into forward financial contracts to hedge the associated price risks to substantially lock in a margin on future transportation activities. The hedging instruments are derivatives, and we reflect changes in the derivatives' fair value in our reported operating results in the period of change, which can be in periods prior to actual utilization of the transportation capacity.

Park and Loan Transactions We routinely enter into park and loan transactions with various pipelines and storage facilities, which allow us 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, we charge, or pay, 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.

We enter into forward NYMEX contracts to hedge the natural gas price risk associated with the 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 our 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, we 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.

Natural Gas Storage Inventory and Transactions We maintain natural gas storage balances for volumes associated with energy marketing activities, parked gas transactions and sales to wholesale and commercial and industrial customers and record these within natural gas stored underground inventory on our Consolidated Statements of Financial Position. Further, and generally in connection with non-affiliated asset management transactions, our recorded natural gas stored underground inventory includes volumes of natural gas that we manage for our customers by purchasing the natural gas inventory from and physically delivering volumes of natural gas back to our customers based on specific delivery dates. The cost at which we purchase the volumes of natural gas from our customers, or WACOG, is also the same price at which we sell the natural gas volumes to our customers. Consequently, we make no margin on the purchase and sale of the natural gas but make operating margin through our natural gas storage optimization activities of these volumes under management. As of December 31, 2012, we had $262 million of natural gas stored underground inventory within our Consolidated Statements of Financial Position, representing 89 Bcf at an overall WACOG of $2.94.

Natural Gas Price Volatility and Energy Marketing Activities We purchase natural gas for storage when the current market price we pay plus the cost for transportation, storage and financing is less than the market price we anticipate we could receive in the future. We attempt to mitigate substantially all of the commodity price risk associated with our storage portfolio by using derivative instruments to reduce the risk associated with future changes in the price of natural gas. We sell NYMEX futures contracts or OTC derivatives in forward months to substantially lock in the operating revenue we will ultimately realize when the stored gas is actually sold.

We view our trading margins from two perspectives. First, we base our commercial decisions on economic value, which is defined as the 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 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 eventual customer.

We account for natural gas stored in inventory differently than the derivatives we use to mitigate the commodity price risk associated with our storage portfolio. The natural gas that we purchase and inject into storage is accounted for at the LOCOM value. The derivatives we use 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 wholesale services 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 wholesale services period-over-period results, since changes in forward NYMEX prices do not increase and decrease on a consistent basis from year to year.

Volatility in the natural gas market arises from a number of factors such as weather fluctuations or changes in supply or demand for natural gas in different regions of the country. The volatility of natural gas commodity prices has 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 2012, 2011 and 2010, the volatility of daily Henry Hub spot market prices for natural gas in the United States was significantly lower than it had been for several prior years. This is the result of a robust natural gas supply, the weak economy, mild weather 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, particularly in the Marcellus Shale producing region where Sequent has natural gas receipt requirements, and the lack of demand growth 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. Consequently, we are repositioning Sequent's business model with respect to fixed costs and the types of contracts pursued and executed.

Sequent's expected natural gas withdrawals from 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, 2012 and 2011. 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	**Total storage** (in Bcf) (WACOG $2.78)	**Expected operating revenues** *(in millions)*
2013		
First quarter	38	$17
Second quarter	9	6
Third quarter	3	3
Fourth quarter	1	1
Total at December 31, 2012	51	$27
Total at December 31, 2011	37	$3

Sequent's storage balances and expected operating revenues are higher in 2012 than 2011, reflecting the effects of the warmer weather in 2012, year-over-year improvements in seasonal price differentials and the ability to achieve higher economic value in 2013 than 2012. If Sequent's storage withdrawals associated with existing inventory positions are executed as planned, it expects operating revenues from storage withdrawals of $27 million in 2013. 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.

The operating revenues expected to be generated from the physical withdrawal of natural gas from storage, do not reflect the earnings impact related to the movement in our hedges to lock in the forward location spread for the delivery of natural gas between two transportation delivery points associated with our transportation capacity portfolio. For the year ended December 31, 2012, we have recorded $3 million in losses associated with the hedging of our transportation portfolio, or $11 million lower as compared to the same period last year. These hedge losses primarily relate to forward transportation and commodity positions for 2013, during which we expect to physically flow natural gas between the hedged transportation delivery points and utilize the contracted transportation capacity. For more information on Sequent's energy marketing and risk management activities, see Item 7A, "Quantitative and Qualitative Disclosures About Market Risk" under the caption "Natural Gas Price Risk."

Midstream Operations

Our midstream operations segment includes a number of businesses that are related and complementary to our primary business of natural gas distribution. The most significant of these is our natural gas storage business, which develops, acquires and operates high-deliverability underground natural gas storage assets primarily in the Gulf Coast region of the United States and in northern California. While this business can generate additional revenue during times of peak market demand for natural gas storage services, the majority of our natural gas storage facilities are contracted through a portfolio of short, medium and long-term contracts at a fixed market rate.

The market fundamentals of the natural gas storage business are cyclical. Low natural gas prices and lack of volatility in recent years have negatively impacted the profitability of our storage facilities as expiring storage capacity contracts were re-subscribed at lower prices. We anticipate lower natural gas prices to continue in 2013 as compared to historical averages. The prices for natural gas storage capacity are expected to increase as supply and demand quantities reach equilibrium as the economy improves, and/or natural gas demand increases in response to low prices and expanded uses for natural gas. While the natural gas market is growing there are significant barriers to develop new storage facilities which we believe provide our storage facilities with an advantage as market conditions improve. The following table shows the working gas capacity and firm subscription amounts by storage facility as of December 31, 2012.

				Subscribed (2)	
In Bcf	**State**	**Type**	**Working Gas Capacity**	**Amount**	**%**
Jefferson Island	Louisiana	Salt-dome	7.3	6.1	84%
Golden Triangle Storage (1)	Texas	Salt-dome	13.5	4.0	30%
Central Valley	California	Depleted field	11.0	4.5	41%
Total			31.8	14.6	

(1) In January 2013, we began an assessment of the working gas capacity at Cavern 1, which is expected to slightly increase the size of the facility. The process is expected to continue through the third quarter of 2013. Cavern 2 will cover the obligations of Cavern 1 during this process.
(2) The amount and percentage of firm capacity under subscription does not include 1 Bcf of capacity under contract at Jefferson Island and 2 Bcf of capacity under contract at Golden Triangle Storage by Sequent at December 31, 2012.

Jefferson Island This wholly owned subsidiary operates a salt-dome storage and hub facility approximately eight miles from the Henry Hub. 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 direct interconnections with eight pipelines in the area. The level of firm subscription has remained consistent over the last three years. We intend to solicit interest for 3.4 Bcf of subscribed capacity at an average rate of $0.103 per Bcf that expires at the end of March 2013, and expect the subscription rate to be lower than the current contract.

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. We continue to seek approval to expand our storage facility; however, we cannot predict when or if this approval will be obtained. The expansion would increase the total working gas capacity at Jefferson Island to approximately 19.5 Bcf of working gas capacity.

Golden Triangle Storage This wholly owned subsidiary operates a salt-dome storage facility and is regulated by the FERC. Golden Triangle Storage owns an approximately nine-mile dual 24" natural gas pipeline to connect the storage facility with three interstate and three intrastate pipelines.

Cavern 1, with 6 Bcf of working capacity, began commercial service in September 2010. Cavern 2, with 7.5 Bcf of working capacity, began commercial operations in September 2012. We spent $15 million in capital expenditures for this project in 2012. At the end of March 2013, Golden Triangle Storage has 2 Bcf of firm contracted capacity at an expiring rate of $0.045 per Bcf. We will evaluate our strategy to re-contract the facility on a firm basis or to provide other services in order to contract at rates at or above the expiring rate.

Central Valley This wholly owned subsidiary operates an underground natural gas storage facility in the Sacramento River valley of north-central California. We converted the depleted Princeton Gas Field into a high-deliverability, multi-cycle storage field. This includes the addition of a 14.9 mile 24-inch diameter gas pipeline connecting the facility to a major pipeline. The storage facility is regulated by the California Commission. Central Valley began commercial operations and providing services to firm customers during the second quarter 2012, with 4.5 Bcf subscribed at December 31, 2012. We plan to solicit interest for additional firm capacity up to 3 Bcf and provide additional storage services for the remaining open capacity.

Magnolia This wholly owned subsidiary operates a pipeline that provides our Georgia customers access to LNG from the Elba Island terminal near Savannah, Georgia. The pipeline was completed in November 2009, and provides diversification of natural gas sources and increased reliability of service in the event that supplies coming from other supply sources are disrupted.

Horizon Pipeline This 50% owned joint venture with Natural Gas Pipeline Company of America operates an approximate 70 mile natural gas pipeline stretching from Joliet, Illinois to near the Wisconsin/Illinois border. Nicor Gas has contracted for approximately 80% of Horizon Pipeline's total throughput capacity of 0.38 Bcf under an agreement expiring in 2015 at rates that have been accepted by the FERC.

Competition Our natural gas storage facilities primarily 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. Competition for our Central Valley storage facility primarily consists of storage facilities in northern California and western North America. Storage values have declined over the past three years due to low gas prices, abundant supplies of natural gas and low volatility and we expect this to continue in 2013 and potentially longer.

Cargo Shipping

Our cargo shipping segment consists of Tropical Shipping, multiple wholly owned foreign subsidiaries of Tropical Shipping that are treated as disregarded entities for United States income tax purposes, Seven Seas, a wholly owned domestic cargo insurance company and an equity investment in Triton, a cargo container leasing business.

Tropical Shipping is a transporter of containerized freight and provides southbound scheduled services from the United States and Canada to twenty-five ports in the Bahamas and the Caribbean, interisland service between several of the Caribbean ports and operates from St. Thomas and St. Croix as its hubs in the Caribbean. In addition, it provides northbound shipments from those islands to the United States and Canada. Other related services, such as inland transportation and cargo insurance, are also provided by Tropical Shipping or its other subsidiaries and affiliates.

Tropical Shipping's southbound cargo consists mainly of building materials, food and other necessities for developers, distributors and residents in the Caribbean and the Bahamas, as well as tourist-related shipments intended for use by hotels, resorts, and cruise ships. Tropical Shipping's interisland shipments consist primarily of consumer staples and northbound shipments primarily consist of apparel, rum and agricultural products.

On average, approximately 70% - 75% of Tropical Shipping's total volumes shipped are in the southbound market, 15% - 20% interisland and 5% - 10% northbound. Tropical Shipping measures volumes and capacity of vessels and containers in TEU's. Details of Tropical Shipping's properties are discussed in Item 2, "Properties" under the caption "Vessels and shipping containers."

Tropical Shipping's operations are structured to allow us to take advantage of certain provisions of the American Jobs Creation Act of 2004 that provide the opportunity for certain tax savings. Generally, to the extent foreign shipping earnings are not repatriated to the United States, these earnings are not expected to be subject to current taxation. To the extent such earnings are expected to be indefinitely reinvested offshore, no deferred income tax expense is recorded by the company. For more information on management's indefinite reinvestment assertion, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," under the caption "Liquidity and Capital Resources." See also Note 2 and Note 12 to our consolidated financial statements under Item 8 herein.

Our cargo shipping segment also includes Triton, a full-service global leasing company and an owner-lessor of marine intermodal cargo containers. Profits and losses are generally allocated to investor's capital accounts in proportion to their capital contributions. Our investment in Triton is accounted for under the equity method, and our share of earnings is reported within "Other Income" on our Consolidated Statements of Income. For more information about our investment in Triton, see Note 10 to the consolidated financial statements under Item 8 herein.

Seven Seas is a Florida domestic insurance corporation that provides cargo insurance policies mainly between Tropical Shipping and its customers. During 2012, 66% of Seven Seas' revenues were generated from Tropical Shipping's customers. Policy coverage is from the point when the cargo leaves the shipper's possession to the point when the customer takes delivery.

Competition Cargo shipping has five main competitors that serve the same major transportation areas. Our volumes shipped increased during 2012, but were partially offset by lower overall shipping rates.

Operations Tropical Shipping's operating results are cyclical and very much aligned with the level of global gross domestic product, tourism and the cost of fuel. Overall, the economies of the Bahamas and the Virgin Islands are highly dependent on tourism from the United States, and the Caribbean's Windward and Leeward Island economies primarily depend on tourism from Europe. Fuel price volatility also impacts our earnings. Bunker surcharge rates are charged to customers and are used to mitigate the fluctuations in fuel transportation costs. In 2013, we expect similar general market challenges as those experienced in 2012 with respect to overall levels of competition and related impacts on shipping volumes and rate pressure.

Tropical Shipping generates revenues primarily by three main services, which include Full Container Load (FCL) service, Less-than Container Load (LCL) service and break bulk service, which is cargo that cannot ship in a container. Tropical Shipping also generates revenues from handling "project cargo," which provides a coordinated service for construction projects. Tropical Shipping's FCL cargo service revenues typically consist of an empty container delivery to the customer's site via truck or rail or coordinating a customer pick up at the port. The customer fills and seals the container and either requests Tropical to pick it up or delivers it back to the port. Tropical Shipping generates revenues from LCL services primarily by providing packaging and transporting services for smaller cargos or customers, including individuals, who may have only a few items to ship.

Seven Seas generates revenues from premiums received on insurance policies subscribed to primarily by customers of Tropical Shipping. Seven Seas' results depend on its ability to generate revenues from the premiums and to manage risk.

Other

Our other segment primarily includes our non-operating 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. However, merger-related costs are not allocated to our operating segments.

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. This 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 December 31, 2012, we had approximately 6,121 employees, 5,649 of whom were in the United States.

The following table provides information about our natural gas utilities' collective bargaining agreements, which represent approximately 27% of our total employees.

	# of Employees	Contract Expiration Date
Nicor Gas		
International Brotherhood of Electrical Workers (Local No. 19)	1,338	February 2014
Virginia Natural Gas		
International Brotherhood of Electrical Workers (Local No. 50)	127	May 2015
Elizabethtown Gas		
Utility Workers Union of America (Local No. 424)	173	November 2015
Total	1,638	

We believe that we have a good working relationship with our unionized employees and there have been no work stoppages at Virginia Natural Gas, Elizabethtown Gas, or Nicor Gas since we acquired those operations in 2000, 2004, and 2011, respectively. As we have historically done, we remain committed to work in good faith with the unions to renew or renegotiate collective bargaining agreements that balance the needs of the Company and our employees. 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.

Available Information

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and proxy statements, and amendments to those reports that we file with, or furnish to, the SEC are available free of charge at the SEC website http://www.sec.gov and 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
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 2013 annual meeting of shareholders. We expect to file that Proxy Statement with the SEC on or about March 15, 2013, and we will make it available on our website as soon as reasonably practicable. Please refer to the Proxy Statement when it is available.

Additionally, our corporate governance guidelines, code of ethics, code of business conduct and the charters of each 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 regulatory authorities in Illinois, Georgia, Virginia, New Jersey, Florida, Tennessee and Maryland.

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 program and environmental remediation activities, energy efficiency programs, 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.

We could incur significant compliance costs if we are required to 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, 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.

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 associated with storage, transportation, treatment and disposal of MGP residuals and waste 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 also could be revised or reinterpreted, and new laws and regulations could be adopted or become applicable to us or our facilities. 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, and such expenditures may not be 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.

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

We must construct additions and replacements to our natural gas distribution systems to continue the expansion of our customer base and improve system reliability, especially during peak usage. We also may need to construct expansions of our existing natural gas storage facilities or develop and construct new natural gas storage facilities. The cost of such 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, the projected construction schedule and the completion timeline of a project. Our cash flows may not be fully adequate to finance the cost of such 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 it may impair our ability to complete the expansions or development projects. We anticipate spending $212 million on these types of programs in 2013.

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

Climate change is expected to receive increasing attention from the current federal administration, non-governmental organizations and legislators. Debate continues as to the extent to which our climate is changing, the potential causes of any 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 that directly affect our operations. However, there is the possibility of new legislative and regulatory proposals to address greenhouse gas emissions, which are in various phases of discussion or implementation. Absent new enabling legislation, in 2012 the United States Environmental Protection Agency has begun using provisions of the 1990 Clean Air Act Amendments to treat carbon dioxide as a pollutant to regulate existing sources of emissions, such as automobiles. Enhanced reporting and categorization of sources is now in place, but additional and potentially costly controls are currently not required in our operations.

The outcome of additional federal and state actions to address climate change could potentially result in new regulations, additional charges to fund energy efficiency activities or other regulatory actions, which in turn could:

- result in increased costs associated with our operations,
- increase other costs to our business,
- affect the demand for natural gas (positively or negatively), and
- impact the prices we charge our customers.

Because natural gas is a fossil fuel with low carbon content, it is likely that future carbon constraints will create additional demand for natural gas, both for production of electricity and direct use in homes and businesses. The impact is already being seen in the power production sector due to both environmental regulations and low natural gas costs.

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 retail businesses is affected by competition from other energy marketers providing retail natural gas services in our service territories, most notably in Illinois and Georgia. 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 natural gas costs, could also cause these customers to bypass or disconnect from our systems in favor of special competitive contracts with lower per-unit costs.

Our retail energy business markets fixed-price and fixed-bill contracts that protect customers against higher natural gas prices, or protect customers against both higher natural gas prices and colder weather. The sale of these fixed-price contracts may be adversely affected if natural gas prices are, or are perceived to be, low and stable.

Our retail services business faces risks in the form of price, convenience and service competition from other warranty and HVAC companies. Retail services also bears risk from potential changes in the regulatory environment, and in fact regulatory-change risk was incurred in late 2011. As a condition of the merger, Nicor Gas is no longer permitted to use its call center personnel to solicit its affiliates' products, most notably the warranty products offered by Nicor Services.

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.

Our midstream operations segment competes 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. Competition for our Central Valley storage facility in northern California primarily consists of storage facilities in northern California and western North America. Storage values have declined over the past three years due to low gas prices and low volatility and we expect this to continue in 2013.

Our cargo shipping segment competes with international maritime companies. The current expansion of the Panama Canal, which is expected to be completed and open for commercial ship transit in 2015, may lead to increased competition as larger vessels may gain access to the Caribbean. In addition, the growing development of the global logistic environment has moved away from port-to-port operations and towards the combined transport supply chain of various combinations of road, rail, sea and inland waterways. Globally, this has resulted in the need to improve ship productivity, sometimes via third party ship management, development of hub and spoke systems, larger ships, faster ship turnaround time and increased use of technology. Additionally, there are increased pricing pressures and decreased shipping volumes for the islands that Tropical Shipping currently serves. Increased competition may affect our volumes, market share, pricing structure and operating margin. Tropical Shipping does not have fuel contracts, but reduces its fuel price risk through fuel surcharges. Tropical Shipping has five primary competitors that serve the same major areas, some of which are larger and better capitalized than we are and have more global exposure than we do.

Changes or downturns in the economy could adversely affect our customers and negatively impact our financial results.

The weak economy in the United States has adversely impacted the financial well-being of many households in the United States. While the economy of the United States seems to be slowly improving, we cannot predict if the administrative and legislative actions to address this situation will be successful in reducing the severity or duration of this downturn. 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. Sales to large industrial customers may be impacted by economic downturns. The manufacturing industry in the United States is subject to changing market conditions including international competition, fluctuating product demand and increased costs and regulation.

Tropical Shipping's business consists primarily of the shipment of building materials, food and other necessities from the United States and Canada to developers, distributors and residents in the Bahamas and the Caribbean region, as well as tourist-related shipments intended for use in hotels, resorts and on cruise ships. As a result, Tropical Shipping's results of operations, cash flows and financial condition can be significantly affected by adverse general economic conditions in the United States, Bahamas, Caribbean region and Canada. Also, a shift in buying patterns that results in such goods being sourced directly from other parts of the world, including China and India, rather than the United States and Canada, could significantly affect Tropical Shipping's results of operations, cash flows and financial condition.

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

Nicor Gas and Sequent often extend credit to their counterparties. Despite performing credit analyses prior to extending credit and seeking to effectuate netting agreements, Nicor Gas and Sequent are exposed to the risk that they may not be able to collect amounts owed to them. If the counterparty to such a transaction fails to perform and any collateral Nicor Gas or Sequent has secured is inadequate, they 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 50% of Sequent's credit exposure 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 to Sequent could result in credit losses that would negatively impact our wholesale services segment.

We have accounts receivable collection risks in Georgia due to a concentration of credit risks related to the provision of natural gas services to Marketers. At December 31, 2012, Atlanta Gas Light provided services to eleven certificated and active Marketers in Georgia, four of which (based on customer count) accounted for approximately 17% of our consolidated operating margin for 2012. 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 guarantees. 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.

The asset management arrangements between Sequent and our local distribution companies, and between Sequent and its non-affiliated customers, may not be renewed or may be renewed at lower levels, which could have a significant impact on Sequent's business.

Sequent currently manages the storage and transportation assets of our affiliates Atlanta Gas Light, Virginia Natural Gas, Elizabethtown Gas, Florida City Gas, Chattanooga Gas and Elkton Gas. The profits it earns from the management of those assets with these affiliates are shared with their respective customers and for Atlanta Gas Light with the Georgia Commissions' Universal Service Fund, with the exception of Chattanooga Gas and Elkton Gas where Sequent is assessed annual fixed-fees. Entry into and renewal of these agreements are subject to regulatory approval. The agreements with Florida City Gas, Chattanooga Gas and Elizabethtown Gas expire in March 2014 and we cannot predict whether such agreements will be renewed or the terms of such renewal.

Sequent also has asset management agreements with certain non-affiliated customers. Sequent's results could be significantly impacted if these agreements are not renewed or are amended or renewed with less favorable terms.

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

The commodity, storage and transportation portfolios at Sequent and the commodity and storage portfolios at midstream operations and 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, our portfolio of positions as of December 31, 2012 had a VaR of $1.8 million at wholesale services and less than $0.1 million at retail operations.

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.

At Nicor Gas, approximately 50% of all usage is for space heating and approximately 75% of the usage and revenues occur from October through March. Weather fluctuations have the potential to significantly impact year-to-year comparisons of operating income and cash flow. We estimate that a 100 degree-day variation from normal weather impacts Nicor Gas' margin, net of income taxes, by approximately $1 million under its current rate structure.

We have a WNA mechanism for Virginia Natural Gas, Elizabethtown Gas and Chattanooga Gas that partially offsets the impact of unusually cold or warm weather on residential and commercial customer billings and on 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%.

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.

Wholesale services' earnings are impacted by changes in weather conditions as weather impacts the demand for natural gas and volatility in the natural gas market. The volatility of natural gas commodity prices has 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. The volatility of natural gas prices has been significantly lower than it has been for several prior years in part due to mild hurricane seasons and mild summer and winter weather. Through the acquisition of natural gas and hedging of natural gas prices, wholesale services reduces the risk to its results of operations, cash flows and financial condition.

Tropical Shipping's operations are affected by weather conditions in Florida, Canada, the Bahamas and Caribbean regions. During hurricane season in the summer and fall, Tropical Shipping may be subject to revenue loss, higher operating expenses, business interruptions, delays, and ship, equipment and facilities damage which could adversely affect Tropical Shipping's results of operations, cash flows and financial condition. In addition, Seven Seas' results of operations, cash flows and financial condition may be adversely affected due to increased insured losses relating to claims arising from hurricane-related events.

Nicor Solutions and Nicor Advanced Energy offer utility-bill management products that mitigate and/or eliminate the risks to customers of variations in weather and we hedge this risk to reduce any adverse effect to our results of operations, cash flows and financial condition.

A decrease in the availability of adequate pipeline transportation capacity due to weather conditions could reduce our revenues and profits. Our gas supply for our distribution operations, retail operations, wholesale services and midstream operations segments depends on 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.

We have confirmed ten sites in Georgia and three in Florida where Atlanta Gas Light, or its predecessors, own all or part of an MGP site. We are required to investigate possible environmental contamination at those MGP sites and, if necessary, cleanup any contamination. As of December 31, 2012, 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, 2012, projected costs related to the MGP sites associated with Atlanta Gas Light range from $65 million to $118 million. For elements of the MGP program where we still cannot provide engineering cost estimates, considerable variability remains in future cost estimates.

We have identified 26 sites in Illinois for which we may have some responsibility. Nicor Gas and Commonwealth Edison Company are parties to an agreement to cooperate in cleaning up residue at many of these sites. The agreement allocates to Nicor Gas 51.7% of cleanup costs for 23 sites. In addition to the agreement with Commonwealth Edison Company there are 3 sites in which we have sole responsibility. Information regarding site reviews has been presented to the Illinois Environmental Protection Agency for certain sites. The results of the detailed site-by-site investigations determined the extent additional remediation is necessary and provided a basis for estimating additional future costs. Our ERC liabilities are customarily reported estimates of future remediation costs for our former operating sites that are contaminated based on our probabilistic models of potential costs and on an undiscounted basis. In 2012, we completed our probabilistic models and engineering estimates for our sites in Illinois, which primarily contributed to the $117 million increase from the amount recorded at December 31, 2011. Based on the estimates we have performed, the cleanup costs for these Illinois sites range from $243 million to $489 million. In accordance with Illinois Commission authorization, we have been recovering, and expect to continue to recover, these costs from our customers, subject to annual prudence reviews.

In addition, we are associated with former MGP 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, preliminary cleanup cost estimates range from $122 million to $209 million. Preliminary costs have been estimated at $11 million for one site in North Carolina.

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

Inflation has caused increases in certain operating 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 could 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, we would expect increases in our short-term debt, accounts receivable and bad debt expense.

Finally, higher costs of natural gas can cause our utility customers to conserve their use of our gas services or switch to other competing products. Higher natural gas costs may increase competition from products utilizing alternative energy sources for applications that have traditionally used natural gas, encouraging some customers to move away from natural gas fueled equipment to equipment fueled by other energy sources.

The cost of providing retirement plan benefits to eligible employees and qualified retirees is subject to changes in pension fund values and changes in liabilities as a result of updated demographics and assumptions. These changes may have a material adverse effect on our financial results.

Effective December 31, 2012, the Nicor Companies Pension and Retirement Plan (Nicor Plan) and the Employees' Retirement Plan of NUI Corporation (NUI Plan) were merged with and into the AGL Resources Inc. Retirement Plan (AGL Plan). In addition, the Nicor Welfare Plan was terminated and as of January 1, 2013, all participants under that plan became eligible to participate in the AGL Welfare Plan. This change in plan participation eligibility did not affect the benefit terms.

The Nicor Plan is a noncontributory defined benefit pension plan covering substantially all of its employees hired prior to 1998 and a retiree health care plan for the benefit of substantially all of its employees (Nicor Gas retirees make contributions to their health care plan). AGL Resources maintains a noncontributory defined benefit pension plan and retiree health care plan for its pre-Nicor merger full-time employees and qualified retirees. Further, the AGL retiree health care plan only includes medical coverage for eligible AGL Resources employees who were employed as of June 30, 2002, if they reach retirement age while working for us; additionally the pre-65 retirees make contributions to their health care plan. Effective January 1, 2012, the AGL Plan was frozen with respect to participation for non-union employees hired on or after that date. Such employees will be entitled to employer provided benefits under their defined contribution plan, that exceed defined contribution benefits for employees who participate in the defined benefit plans.

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 and assumptions, 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 and a charge to our other comprehensive income to the extent that the actual return on assets in the pension fund is less than the expected return. We may be required to make additional contributions in 2013 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, 2012, our pension plans assets represented 80% of our total pension plan obligations.

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 Other Retirement Plans" and Note 6 to the consolidated financial statements under Item 8 herein.

Natural disasters, terrorist activities and the potential for military and other actions could adversely affect our businesses.

Natural disasters may damage our assets and interrupt our business operations. 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.

Changes in the laws and regulations regarding the sale and marketing of products and services offered by our retail operations segment could adversely affect our results of operations, cash flows and financial condition.

Our retail operations segment provides various energy-related products and services. These include sales of natural gas and utility-bill management services to residential and small commercial customers, and the sale, repair, maintenance and warranty of heating, air conditioning and indoor air quality equipment. The sale and marketing of these products and services are subject to various state and federal laws and regulations. Changes in these laws and regulations could impose additional costs on or restrict or prohibit certain activities, which could adversely affect our results of operations, cash flows and financial condition.

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. We are not aware of any movement to do so, but it is possible that the legislature could reverse or amend portions of the deregulation process.

Changes in the laws and regulations regarding maritime activities offered by our cargo shipping segment could adversely affect our results of operations, cash flows and financial condition.

Tropical Shipping is subject to the International Ship and Port Facility Security Code and is also subject to the United States Maritime Transportation Security Act, both of which require extensive security assessments, plans and procedures. Tropical Shipping is also subject to the regulations of the Federal Maritime Commission, the Surface Transportation Board, as well as other federal agencies and local laws, where applicable. Additional costs that could result from changes in the rules and regulations of these regulatory agencies would adversely affect our results of operations, cash flows and financial condition.

Conservation could adversely affect our results of operations, cash flows and financial condition.

As a result of recent legislative and regulatory initiatives on energy conservation, we have put into place programs to promote additional energy efficiency by our customers. Funding for such programs is being recovered through cost recovery riders. However, the adverse impact of lower deliveries and resulting reduced margin could adversely affect our results of operations, cash flows and financial condition.

A security breach could disrupt our operating systems, shutdown our facilities or expose confidential personal information.

Security breaches of our information technology infrastructure, including cyber-attacks and cyber terrorism, could lead to system disruptions or generate facility shutdowns. If such an attack or security breach were to occur, our business, results of operations and financial condition could be materially adversely affected. In addition, such an attack could affect our ability to service our indebtedness, our ability to raise capital and our future growth opportunities.

Additionally, the protection of customer, employee and company data is critical to us. A breakdown or a breach in our systems that results in the unauthorized release of individually identifiable customer or other sensitive data could occur and have a material adverse effect on our reputation, operating results and financial condition. Such a breakdown or breach could also materially increase the costs we incur to protect against such risks. There is no guarantee that the procedures that we have implemented to protect against unauthorized access to secured data are adequate to safeguard against all data security breaches.

We could be adversely affected by violations of the Foreign Corrupt Practices Act and similar worldwide anti-bribery laws.

Our international operations require us to comply with a number of U.S. and international laws and regulations, including those involving anti-bribery and anti-corruption. The Foreign Corrupt Practices Act (FCPA) generally prohibits United States companies and their intermediaries from making improper payments to foreign officials for the purpose of obtaining or maintaining business or obtaining an improper business benefit. Although our policies require compliance with these laws, we may be held liable for actions taken by our strategic or local partners in foreign jurisdictions, even though these partners may not be subject to the FCPA. Violations of these laws, or allegations of such violations, could disrupt our business and result in a material adverse effect on our business and results of operations, cash flows and financial condition.

We may pursue acquisitions, divestitures and other strategic transactions, the success of which may impact our results of operations, cash flows and financial condition.

In the past, we have pursued acquisitions to complement or expand our business, divestures and other strategic transactions. Such future transactions are part of our general strategic objectives and may occur. If we identify an acquisition candidate, we may not be able to successfully negotiate or finance the acquisition or integrate the acquired businesses with our existing business and services. Future acquisitions could result in potentially dilutive issuances of equity securities and the incurrence of debt and contingent liabilities, amortization expenses and substantial goodwill. We may be affected materially and adversely if we are unable to successfully integrate businesses that we acquire. Similarly, we may divest portions of our business, which may also have material and adverse effects.

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 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 facilities 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.

The AGL Credit Facility and the Nicor Gas Credit Facility 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 of 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, or may require us to provide additional collateral to certain counterparties.

Our senior 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.

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. In December 2012, Fitch lowered the ratings of AGL Resources from A- to BBB+. There are no implications of this downgrade on our corporate funding ability or our ability to access the capital markets, nor does this downgrade trigger any collateralization requirements under our corporate guarantees. As of December 31, 2012, if our credit rating had fallen below investment grade, we would have been required to provide collateral of $22 million to continue conducting business with certain customers. For additional credit rating information, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Liquidity and Capital Resources."

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" Under the caption "Interest Rate 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 significant 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 the net income and cash flows of our subsidiaries and their ability to pay upstream dividends or other distributions to meet our financial obligations and to pay dividends on our common stock. The ability of our subsidiaries to pay upstream dividends and make other distributions is subject to applicable state law and regulatory restrictions. In addition, Nicor Gas is not permitted to make money pool loans to affiliates. Refer to Item 5, "Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities" for additional information. Our subsidiaries are separate legal entities and have no obligation to provide us with funds.

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 addition, derivative contracts entered for hedging purposes may not offset the underlying exposure being hedged as expected, resulting in financial losses. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these derivative 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 reported fair value of these contracts.

The Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 introduced a comprehensive new regulatory framework requiring certain over-the-counter derivatives, or swaps, to be centrally cleared and executed through an exchange or other approved trading platform. Although the CFTC and the SEC are still in the process of adopting rules to implement the new framework, based on current interpretation, we were not considered to be a "swap dealer" or "major swap participant" in 2012 so we were exempt from the clearing, exchange trading and margin requirements under the Dodd-Frank Act. If these provisions were to apply to our derivative activities, we could be subject to higher costs for our derivative activities, including from higher margin requirements. In addition, implementation of, and compliance with, the over-the-counter derivatives provisions of the Dodd-Frank Act by our swap counterparties could result in increased costs related to our derivative activities.

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

The AGL Credit Facility and the Nicor Gas Credit 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 our other debt agreements, obligated in such instance to satisfy a large portion of our outstanding indebtedness and unable to satisfy all of our outstanding obligations simultaneously.

Changes in taxation could adversely affect our results of operations, cash flows and financial condition.

Various tax and fee increases may occur in locations in which we operate. We cannot predict whether other legislation or regulation will be introduced, the form of any legislation or regulation, or whether any such legislation or regulation will be passed by the legislatures or other governmental bodies. New taxes or an increase in tax rates would increase tax expense and could adversely affect our results of operations, cash flows and financial condition.

Risks Related to Our Merger with Nicor

Our merger with Nicor may not achieve its intended results and we may be unable to fully integrate successfully.

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. Achieving the anticipated benefits of the merger depends on whether the businesses can be integrated completely in an efficient and effective manner. Integration could take longer than anticipated and could result in the loss of valuable employees, the disruption of our ongoing businesses, processes and systems or inconsistencies in standards, controls, procedures, practices, policies and compensation arrangements, any of which could adversely affect our ability to achieve the anticipated benefits of the merger. We may have difficulty addressing possible differences in corporate cultures and management philosophies. Many of our employees are in new positions following the merger and are required to comply with policies that are new to them, including policies related to risk management. The integration process is subject to a number of uncertainties, and no assurance can be given that the anticipated benefits will be realized or, if realized, the timing of their realization. Failure to achieve these anticipated benefits could result in increased costs or decreases in the amount of expected revenues and could adversely affect our future business, financial condition, operating results and prospects.

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 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.

In connection with the Nicor merger, we recorded goodwill and long-lived assets, including intangible assets, which could become impaired and adversely affect our financial condition and results of operations.

We assess goodwill for impairment at least annually and more frequently if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value. We assess our long-lived assets, including intangible assets, for impairment whenever events or circumstances indicate that an asset's carrying amount may not be recoverable. To the extent the value of goodwill or long-lived assets become impaired, we may be required to incur impairment charges that could have a material impact on our results of operations. No impairment of goodwill was recorded as a result of our 2012 annual impairment testing as the fair value of each reporting unit was in excess of the carrying value. Additionally, no impairment of long-lived assets was recorded during 2012.

Since interest rates are a key component, among other assumptions, in the models used to estimate the fair values of our reporting units, as interest rates rise, the calculated fair values decrease and future impairments may occur. Further, the rates for contracting capacity at Jefferson Island, Golden Triangle Storage and Central Valley are also key components in the models used to estimate their fair value. Consequently, a further decline in market fundamentals and the rates for contracting availability could result in future impairments. Due to the subjectivity of the assumptions and estimates underlying the impairment analysis, we cannot provide assurance that future analyses will not result in impairment. These assumptions and estimates include projected cash flows, current and future rates for contracted capacity, growth rates, weighted average cost of capital and market multiples. For additional information, see Item 7, "Critical Accounting Policies and Estimates."

Our indebtedness following the merger is higher than our previous 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 assumed Nicor's outstanding debt and incurred additional debt to pay the cash portion of the merger consideration and transactions expenses. Our total indebtedness as of December 31, 2012 was $4.9 billion (including $1.4 billion of short-term borrowings and $3.5 billion of long-term debt and other long-term obligations).

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 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
- 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 remained outstanding after the merger; but there can be no assurance that we will be able to repay or refinance such borrowings and obligations in future periods.

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. 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.

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. Substantially all of Nicor Gas' properties are subject to the lien of the indenture securing its first mortgage bonds. See Note 8 to our consolidated financial statements under Item 8 herein.

Distribution and transmission mains

Our distribution systems transport natural gas from our pipeline suppliers to our customers in our service areas. At December 31, 2012, our distribution operations segment owned approximately 80,000 miles of underground distribution and transmission mains. These distribution and transmission mains are located on easements or rights-of-way which generally provide for perpetual use.

Storage assets

Distribution Operations We own and operate eight underground natural gas storage facilities in Illinois with a total inventory capacity of about 150 Bcf, approximately 135 Bcf of which can be cycled on an annual basis. The system is designed to meet about 50% of the estimated peak-day deliveries and approximately 40% of its normal winter deliveries in Illinois. In addition to the facilities we own, we have about 40 Bcf of purchased storage services under contracts with Natural Gas Pipeline Company of America that expire in 2013. This level of storage capability provides us with supply flexibility, improves the reliability of deliveries and can mitigate the risk associated with seasonal price movements.

We have approximately 7.7 Bcf of LNG storage capacity in seven 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 0.4 Bcf. The LNG plants and propane storage facilities are used by our distribution operations segment to supplement natural gas supply during peak usage periods.

Midstream Operations We own three high-deliverability natural gas storage and hub facilities which are operated by our midstream operations segment. Jefferson Island operates a salt-dome storage facility in Louisiana currently consisting of two salt dome gas storage caverns with approximately 10 Bcf of total capacity and about 7.3 Bcf of working gas capacity. Golden Triangle Storage operates a salt-dome storage facility in Texas designed for approximately 13.5 Bcf of working natural gas capacity and total cavern capacity of 20 Bcf. Cavern 1, with 6 Bcf of working capacity, was completed and began commercial service in September 2010. Cavern 2, with 7.5 Bcf of working capacity, was completed and began commercial service in September 2012. Central Valley developed an underground natural gas storage facility in California with 11 Bcf of working natural gas capacity which was placed into commercial service in June 2012. In addition to the LNG facilities that support utility operations, we have recently placed into commercial operations an LNG facility purchased from the Trussville Utilities District in Alabama. This facility produces LNG for Pivotal LNG, a wholly owned subsidiary, to support its business of selling LNG as a substitute fuel in various market segments.

Vessels and shipping containers

Our cargo shipping segment operates 12 owned vessels and 2 chartered vessels with a container capacity totaling approximately 6,000 TEUs. The owned vessels range in age from 2 - 36 years, and vary in length from 235 - 525 feet. In addition to the vessels, we own and/or lease containers, freight-handling equipment, chassis and other equipment.

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 the 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.

For more information regarding some of these proceedings, see Note 11 to our consolidated financial statements under Item 8 herein under the caption "Litigation."

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR 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 ticker symbol GAS. At January 31, 2013, there were 22,221 record holders of our common stock. Quarterly information concerning our high and low stock prices and cash dividends paid in 2012 and 2011 is as follows:

Quarter ended:	Sales price of common stock High	Low	Cash dividend per common Share	Quarter ended:	Sales price of common stock High	Low	Cash dividend per common share
March 31, 2012	$42.88	$38.42	$0.36	March 31, 2011	$39.91	$35.65	$0.45
June 30, 2012	40.29	36.59	0.46	June 30, 2011	42.34	38.58	0.45
September 30, 2012	41.95	38.45	0.46	September 30, 2011	42.40	34.08	0.45
December 31, 2012	41.71	36.90	0.46	December 31, 2011 (1)	43.69	37.95	0.55
			$1.74				$1.90

(1) As a result of the Nicor merger, AGL Resources shareholders of record as of the close of business on December 8, 2011, received a pro rata dividend of $0.0989 for the stub period, accruing from November 19, 2011. For presentation purposes the amount in the table was rounded to $0.10.

We have historically paid dividends to common shareholders four times a year: March 1, June 1, September 1 and December 1. We have paid 260 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, and
- 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 rights are superior to those of the shareholders receiving the dividends.

Securities Authorized for Issuance Under Equity Compensation Plans

See Part III, Item 12 "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" under the heading "Executive Compensation -- Equity Compensation Plan Information."

Issuer Purchases of Equity Securities

There were no purchases of our common stock by us and any affiliated purchasers during the three months ended December 31, 2012.

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." Material changes from 2011 to 2012 and 2010 to 2011 are primarily due to the Nicor merger which closed on December 9, 2011. See Note 3 to our consolidated financial statements under Item 8 herein for additional merger related information.

Dollars and shares in millions, except per share amounts	**2012** (1)	**2011** (1)	**2010**	**2009**	**2008**
Income statement data					
Operating revenues	$3,922	$2,338	$2,373	$2,317	$2,800
Operating expenses					
Cost of goods sold	1,791	1,097	1,164	1,142	1,654
Operation and maintenance (2)	921	501	497	497	472
Depreciation and amortization	415	186	160	158	152
Nicor merger expenses (2)	20	57	6	0	0
Taxes other than income taxes	165	57	46	44	44
Total operating expenses	3,312	1,898	1,873	1,841	2,322
Operating income	610	440	500	476	478
Other income (expense)	24	7	(1)	9	6
Earnings before interest and taxes (EBIT) (3)	634	447	499	485	484
Interest expenses	184	136	109	101	115
Earnings before income taxes	450	311	390	384	369
Income taxes	164	125	140	135	132
Net income	286	186	250	249	237
Less net income attributable to the noncontrolling interest	15	14	16	27	20
Net income attributable to AGL Resources Inc.	$271	$172	$234	$222	$217
Common stock data					
Weighted average common shares outstanding basic	117.0	80.4	77.4	76.8	76.3
Weighted average common shares outstanding diluted	117.5	80.9	77.8	77.1	76.6
Total shares outstanding (4)	117.9	117.0	78.0	77.5	76.9
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	$2.32	$2.14	$3.02	$2.89	$2.85
Diluted earnings per common share - attributable to AGL Resources Inc. common shareholders	$2.31	$2.12	$3.00	$2.88	$2.84
Dividends declared per common share (5)	$1.74	$1.90	$1.76	$1.72	$1.68
Dividend payout ratio	75%	89%	58%	60%	59%
Dividend yield (6)	4.4%	4.5%	4.9%	4.7%	5.4%
Price range:					
High	$42.88	$43.69	$40.08	$37.52	$39.13
Low	$36.59	$34.08	$34.21	$24.02	$24.02
Close (4)	$39.97	$42.26	$35.85	$36.47	$31.35
Market value (4)	$4,711	$4,946	$2,800	$2,826	$2,411
Statements of Financial Position data (4)					
Total assets	$14,141	$13,913	$7,520	$7,079	$6,710
Property, plant and equipment - net	8,347	7,900	4,405	4,146	3,816
Short-term debt	1,377	1,321	733	602	866
Long-term debt	3,553	3,578	1,971	1,974	1,675
Total debt	4,930	4,899	2,704	2,576	2,541
Total equity	3,435	3,339	1,836	1,819	1,684
Cash flow data					
Net cash flow provided by operating activities	$1,003	$451	$526	$592	$227
Net cash flow used in investing activities	(786)	(1,339)	(442)	(476)	(372)
Net cash flow (used in) provided by financing activities	(155)	933	(86)	(106)	142
Net borrowings and (payments) of short-term debt	56	91	131	(264)	286
Financial ratios (4)					
Debt	59%	59%	60%	59%	60%
Equity	41%	41%	40%	41%	40%
Total	100%	100%	100%	100%	100%
Return on average equity	8.0%	6.6%	12.8%	12.7%	12.8%

(1) Material changes from 2011 to 2012 and 2010 to 2011 are primarily due to the Nicor merger on December 9, 2011. The year ending December 31, 2011 includes only 22 days of Nicor activity from December 10, 2011 through December 31, 2011. See Note 3 for additional merger related information.
(2) Transaction expenses associated with the Nicor merger were excluded from operation and maintenance expenses and presented separately.
(3) This is a non-GAAP measurement. A reconciliation of 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."
(4) As of the last day of the fiscal period.
(5) As a result of the Nicor merger, AGL Resources shareholders of record as of the close of business on December 8, 2011, received a pro rata dividend of $0.0989 for the stub period, accruing from November 19, 2011. For presentation purposes the amount in the table was rounded to $0.10.
(6) Dividends declared per common share during the fiscal period divided by market value per common share as of the last day of the fiscal period.

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

Executive Summary

We are the nation's largest natural gas-only distribution company based on customer count. Our regulated utility and non-regulated businesses are summarized below:

- Seven regulated natural gas distribution companies providing natural gas services to approximately 4.5 million customers in Illinois, Georgia, Virginia, New Jersey, Florida, Tennessee and Maryland
- Over 1 million retail customers in our unregulated businesses
- Physical wholesale gas business delivering approximately 5.5 Bcf of natural gas per day
- Natural gas storage facilities that provided approximately 31.8 Bcf of working gas storage capacity in 2012
- One of the largest containerized cargo carriers in the Caribbean and Bahamas

The following table provides certain information on our segments, which changed as a result of the Nicor merger in 2011. See Note 13 to our consolidated financial statements under Item 8 herein for additional segment information.

	EBIT			Assets			Capital Expenditures		
	2012	2011	2010	2012	2011	2010	2012	2011	2010
Distribution operations	84%	92%	70%	80%	79%	73%	83%	85%	70%
Retail operations	18	21	21	4	4	3	1	1	1
Wholesale services	0	1	10	9	9	18	0	0	0
Midstream operations	2	2	1	5	5	6	8	8	25
Cargo shipping	1	0	n/a	3	3	n/a	1	0	n/a
Other	(5)	(16)	(2)	(1)	0	0	7	6	4
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%

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 proposals 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. In 2013, we anticipate resolution of the Nicor Gas PBR issue, for which we have accrued $72 million as potential refunds to our Illinois customers. Additionally, our pipeline replacement program is expected to be completed in 2013 and we will work to successfully achieve our targets with our other regulatory infrastructure programs. We expect to spend $212 million on these regulatory infrastructure programs in 2013. For more information on our regulatory items and capital projects, see Item 1, "Business - Utility Regulation and Rate Design" and "Capital Projects."

Customer growth initiatives While there has been some improvement in the economic conditions within the areas we serve, we continue to feel the effect of a weak economy. We have experienced a slight customer gain in our distribution operations segment and a slight customer loss in our retail operations segment throughout 2012. We anticipate improved customer trends in 2013 compared to our 2012 results.

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.

Additionally, we intend to expand our retail services business in 2013 to include our service territories in Georgia, Virginia and Tennessee. We anticipate this expansion will provide growth opportunities in 2013 and in the future.

Natural gas price volatility Volatility in the natural gas market arises from a number of factors, such as weather fluctuations or changes in supply or demand for natural gas in different regions of the country. The volatility of natural gas commodity prices has 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 2012 and 2011, the volatility of the daily Henry Hub spot market prices for natural gas in the United States has been significantly lower than it had been in prior years. This is the result of a robust natural gas supply, the weak economy, mild weather and ample storage. Our utility 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 for our utility customers 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. Consequently, we are working to reposition our wholesale services business model with respect to fixed costs and the types of contracts pursued and executed.

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, retail operations and midstream 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 operations, wholesale services and cargo shipping 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, wholesale services operating revenues are impacted due to peak usage by power generators in response to summer energy demands. Seasonality also affects the comparison of certain Consolidated Statements of Financial Position items across quarters, including receivables, unbilled revenue, inventories and short-term debt. However, these items are comparable when reviewing our annual results.

Additionally, the revenues of our cargo shipping business are generally higher in the fourth quarter, as our customers require more tourist-related shipments as the hotels, resorts, and cruise ships typically have increased occupancy rates commencing in the fourth quarter and increasing further into the first quarter and consumer spending increases during traditional holiday periods. Revenues are impacted during the fourth quarter by Peak Season Surcharges in effect from early October through mid-December.

67% of these segments' operating revenues and 75% of these segments' EBIT for the year ended December 31, 2012 were generated during the first and fourth quarters of 2012, and are reflected in our Consolidated Statements of Income for the quarters ended March 31, 2012 and December 31, 2012. Our base operating expenses, excluding cost of goods sold, 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 the majority of 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, commercial and industrial customers from the date of the last bill 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	**2012**	**2011** (1)	**2010**
Residential	$2,011	$1,065	$1,083
Commercial	656	467	521
Transportation	492	403	404
Shipping	342	19	0
Industrial	262	289	205
Other	159	95	160
Total operating revenues	$3,922	$2,338	$2,373

(1) As a result of our merger with Nicor, our results of operations for the year ending December 31, 2011 includes 22 days of activity from the acquired subsidiaries from December 10, 2011 through December 31, 2011.

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 goods sold and revenue tax expense in distribution operations. Operating margin 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 and 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 goods sold and revenue tax expenses can vary significantly and are generally billed directly to our customers. We also consider operating margin to be a better indicator in our retail operations, wholesale services, midstream operations and cargo shipping 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.

We do not routinely engage in transactions of the magnitude of the Nicor merger, and consequently do not regularly incur transaction and integration-related expenses of correlative size. We believe presenting the non-GAAP measurements of basic and diluted earnings per share - as adjusted, which excludes Nicor merger-related expenses, provides investors with an additional measure of our performance. Additionally, we have excluded the additional accrual for the Nicor Gas PBR issue as it was a one-time expense that is not expected to be recurring. Adjusted basic and diluted earnings per share should not be considered an alternative to, or a more meaningful indicator of our operating performance than our GAAP basic and diluted earnings per share. The following table reconciles operating revenue and operating margin to operating income and EBIT to earnings before income taxes and net income and our GAAP basic and diluted earnings per common share to our non-GAAP basic and diluted earnings per share – as adjusted, together with other consolidated financial information for the last three years.

In millions	**2012**	**2011**	**2010**
Operating revenues	$3,922	$2,338	$2,373
Cost of goods sold	(1,791)	(1,097)	(1,164)
Revenue tax expense (1)	(85)	(9)	0
Operating margin (2)	2,046	1,232	1,209
Operating expenses (3) (5)	(1,501)	(744)	(703)
Revenue tax expense (1)	85	9	0
Nicor merger expenses (4)	(20)	(57)	(6)
Operating income	610	440	500
Other income (expense)	24	7	(1)
EBIT	634	447	499
Interest expenses	(184)	(136)	(109)
Earnings before income taxes	450	311	390
Income tax expenses	(164)	(125)	(140)
Net income	286	186	250
Less net income attributable to the noncontrolling interest	15	14	16
Net income attributable to AGL Resources Inc.	$271	$172	$234
Per common share data			
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	$2.32	$2.14	$3.02
Additional accrual for Nicor Gas PBR issue	0.04	0.00	0.00
Transaction costs of Nicor merger	0.11	0.80	0.05
Basic earnings per share – as adjusted	$2.47	$2.94	$3.07
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	$2.31	$2.12	$3.00
Additional accrual for Nicor Gas PBR issue	0.04	0.00	0.00
Transaction costs of Nicor merger	0.11	0.80	0.05
Diluted earnings per share – as adjusted	$2.46	$2.92	$3.05

(1) Adjusted for revenue tax expenses for Nicor Gas which are passed directly through to customers.
(2) Our operating margin was negatively impacted by warmer-than-normal weather by $33 million in 2012.
(3) Excludes expenses associated with the merger with Nicor of $20 million ($13 million net of tax) in 2012, $57 million ($48 million net of tax) in 2011 and $6 million ($4 million net of tax) in 2010.
(4) Expenses associated with the Nicor merger are part of operating expenses, but are shown separately to better compare year-over-year results. Our 2011 merger expenses include debt issuance costs and interest expense on pre-funding the cash portion of the purchase consideration of $25 million ($16 million net of taxes), while there is no such expense in our 2010 merger expenses.
(5) Our 2012 operating expenses were favorably impacted by reduced incentive compensation accruals of $29 million compared to targeted amounts. We expect these amounts to return to targeted levels in 2013.

In 2012, our net income attributable to AGL Resources Inc. increased by $99 million or 58% compared to last year. The increase was primarily the result of increased operating income at distribution operations, retail operations and cargo shipping as a result of the Nicor merger, and increased regulatory infrastructure program revenues at Atlanta Gas Light. The increases were partially offset by the effect of warmer-than-normal weather in our distribution operations and retail operations segments, and significantly lower margins at wholesale services resulting from mark-to-market accounting hedge losses. Additionally, during 2012, we recorded $37 million less expenses associated with the merger with Nicor compared to 2011.

In 2011, our net income attributable to AGL Resources Inc. decreased by $62 million or 26% compared to 2010. The decrease was primarily the result of $57 million ($48 million net of tax) of transaction expenses associated with the merger with Nicor in 2011. We incurred $6 million ($4 million net of tax) of Nicor transaction costs in 2010. Additionally, we experienced reduced EBIT at wholesale services and retail energy operations due to decreased average customer usage, warmer weather, losses associated with pipeline constraints in the Marcellus shale gas region and significantly lower natural gas volatility. This decrease was partially offset by higher EBIT at distribution operations due to increased revenues from new rates at Atlanta Gas Light and increased regulatory infrastructure program revenues at Atlanta Gas Light and Elizabethtown Gas. The decrease in our net income attributable to AGL Resources Inc. was also unfavorably impacted by increased interest expenses resulting from higher average debt outstanding, primarily the result of the additional long-term debt issuance used to fund the Nicor merger. The variances for each operating segment are contained within the year-over-year discussion on the following pages.

Interest expense In 2012 our interest expense increased by $48 million or 35% compared to 2011. These increases were the result of higher average debt outstanding primarily as a result of the additional long-term debt issued to fund the Nicor merger and the long-term debt assumed in the transaction.

The increase in our interest expenses of $27 million in 2011 compared to 2010 was primarily the result of our prefunding the cash portion of the merger consideration through the issuance of $975 million of long-term debt during the year. This increased our annual interest expense by $17 million. The remaining increase during 2011 related primarily to fees paid on our Term Loan Facility and our Bridge Facility, both of which terminated in 2011. 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	2012	2011	2010
Interest expenses	$184	$136	$109
Average debt outstanding (1)	$4,378	$2,652	$2,393
Average rate (2)	4.2%	5.1%	4.6%

(1) Daily average of all outstanding debt.
(2) Increase in the 2011 average interest rate is due to our senior note issuances during the current year.

Income tax expense In 2012, our income tax expense increased by $39 million or 31% compared to the same period in 2011 primarily due to higher consolidated earnings. Our effective tax rate was 37.7% in 2012 compared to 42.2% in 2011. The decreased effective tax rate was primarily due to the non-deductible merger transaction expenses in 2011. Our estimated effective tax rate for 2013 is 37.9%.

In 2011, our income tax expense decreased by $15 million or 11% compared to 2010. The decrease was primarily due to lower consolidated earnings as previously discussed. Our effective tax rate was 42.1% in 2011 and 37.5% in 2010. The increased effective tax rate in 2011 was primarily due to non-deductible merger transaction expenses.

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 our effective tax rate, see Note 12 to our consolidated financial statements under Item 8 herein.

Operating metrics Selected weather, customer and volume metrics for 2012, 2011 and 2010, which we consider to be some of the key performance indicators for our operating segments, are presented in the following tables. For the businesses that were acquired from the Nicor merger we only include the 22 days of activity from December 10, 2011 through December 31, 2011. 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 in our distribution operations and retail operations segments.

Volume metrics for distribution operations and retail operations, as shown in the following table, present the effects of weather and our customers' demand for natural gas compared to prior year. 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.

Wholesale services' daily physical sales volumes represent the daily average natural gas volumes sold to its customers. Within our midstream operations segment, our natural gas storage businesses seek to have a significant percentage of their working natural gas capacity under firm subscription, but also take into account current and expected market conditions. This allows our natural gas storage business to generate additional revenue during times of peak market demand for natural gas storage services, but retain some consistency with their earnings and maximize the value of the investments. Our cargo shipping segment measures the volume of shipments during the period in TEUs. We continue to seek opportunities to profitably increase our number of TEUs and therefore the utilization of our containers and vessels.

Customers (average end-use - in thousands)	Year ended December 31, 2012	2011	2010	2012 vs. 2011 % change	2011 vs. 2010 % change
Distribution Operations	4,459	4,454	2,264	0.1%	n/a
Retail Operations					
Georgia	485	489	496	(1)%	(1)%
Illinois	462	515	n/a	(10)%	n/a
Ohio and Florida (1)	83	104	77	(20)%	35%
Indiana	41	37	n/a	11%	n/a
Other	11	4	n/a	175%	n/a
Total	1,082	1,149	573	(6)%	n/a
Market share in Georgia	32%	33%	33%	(3)%	n/a

Weather (Heating Degree Days) (2)	Normal	2012	2011	2010	2012 vs. 2011 colder (warmer)	2011 vs. 2010 colder (warmer)	2012 vs. normal colder (warmer)	2011 vs. normal colder (warmer)	2010 vs. normal colder (warmer)
Year ended December 31,									
Illinois	5,630	4,863	5,892	n/a	(17)%	n/a	(14)%	5%	n/a
Georgia	2,600	1,934	2,454	3,209	(21)%	(24)%	(26)%	(6)%	23%
Quarter ended December 31,									
Illinois	2,020	1,890	1,810	n/a	4%	n/a	(6)%	(10)%	n/a
Georgia	1,009	878	852	1,187	3%	(28)%	(13)%	(16)%	18%

Volumes	Year ended December 31, 2012	2011	2010	2012 vs. 2011 % change	2011 vs. 2010 % change
Distribution Operations (In Bcf) (3)					
Firm	606	247	243	145%	2%
Interruptible	107	105	99	2%	6%
Total	713	352	342	103%	3%
Retail Operations (In Bcf)					
Georgia firm	31	35	46	(11)%	(24)%
Ohio and Florida	8	9	10	(11)%	(10)%
Wholesale Services					
Daily physical sales (Bcf / day) (3)	5.54	5.21	4.57	6%	14%
Cargo Shipping (TEU's - in thousands)					
Shipments	170	n/a	n/a	n/a	n/a
	As of December 31, 2012	**2011**	**2010**		
Midstream Operations					
Working natural gas capacity (in Bcf) (4) (5)	31.8	13.5	13.5		
% of firm capacity under subscription by third party (6)	46%	68%	51%		

(1) A portion of the Ohio customers represents customer equivalents, which are computed by the actual delivered volumes divided by the expected average customer usage. On April 1, 2012, our contract to serve approximately 50,000 customer equivalents ended.
(2) Obtained from weather stations relevant to our service areas at the National Oceanic and Atmospheric Administration, National Climatic Data Center. For Illinois, normal represents a ten-year average from 1998 through 2007, which was established in our last rate case. For Georgia, normal represents the ten-year average from January 1, 2003 through December 31, 2012.
(3) As of December 31, for each respective year. For the entities acquired from Nicor, 2011 represents volume information only from December 10, 2011 through December 31, 2011.
(4) Includes Central Valley Storage that was acquired in connection with the Nicor merger, which began commercial operations in the second quarter of 2012.
(5) Golden Triangle Storage's Cavern 1 is going through a process to assess the cavern's working gas capacity and to slightly increase the size of the facility. The process began in January 2013 and is expected to continue through the third quarter of 2013. Cavern 2 will cover the obligations of Cavern 1 during this process.
(6) The percentage of capacity under subscription does not include 3 Bcf of capacity under contract with Sequent at December 31, 2012, 4 Bcf of capacity under contract with Sequent at December 31, 2011 and 2 Bcf of capacity under contract with Sequent at December 31, 2010.

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.

	Operating Margin (1) (2)			**Operating Expenses** (2) (3)			**EBIT** (1)		
In millions	**2012**	**2011**(4)	**2010**	**2012**	**2011**(4)	**2010**	**2012**	**2011**(4)	**2010**
Distribution operations	$1,571	$963	$879	$1,048	$557	$531	$532	$412	$352
Retail operations	247	168	183	131	75	80	116	93	103
Wholesale services	50	57	105	54	52	57	(3)	5	49
Midstream operations	46	37	30	38	28	24	10	9	6
Cargo shipping	134	7	n/a	137	8	n/a	8	0	n/a
Other	(2)	0	12	28	72	17	(29)	(72)	(11)
Consolidated	$2,046	$1,232	$1,209	$1,436	$792	$709	$634	$447	$499

(1) These are non-GAAP measures. A reconciliation of operating revenue and operating margin to operating income and EBIT to earnings before income taxes and net income is contained in "Results of Operations." Please note that our segments have changed as a result of our merger with Nicor and amounts from 2011 and 2010 have been reclassified among the segments to reflect these changes. See Note 13 to our consolidated financial statements under Item 8 herein for additional segment information.
(2) Operating margin and expense for 2012 and 2011 are adjusted for revenue tax expense for Nicor Gas, which is passed directly through to customers.
(3) Includes $20 million, $57 million and $6 million for 2012, 2011 and 2010, respectively, in merger expenses associated with the Nicor merger and the $8 million accrual in 2012 for the Nicor Gas PBR issue. For more information see Note 3 to our consolidated financial statements under Item 8 herein. Additionally, includes intercompany eliminations.
(4) The 2011 amounts only include 22 days of Nicor activity from December 10, 2011 through December 31, 2011.

Distribution Operations

Our distribution operations segment is the largest component of our business and is subject to regulation and oversight by agencies in each of the seven 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 second 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. We have various mechanisms, such as weather normalization mechanisms, at all of our utilities, with the exception of Nicor Gas, that limit our exposure to weather changes within typical ranges in their respective service areas. During 2012, warmer-than-normal weather reduced our expected operating margin, primarily at Nicor Gas, by $24 million.

In millions	**2012**	**2011**
EBIT - prior year	**$412**	**$352**
Operating margin		
Increased margin from Nicor Gas as a result the Nicor merger in December 2011	596	47
Increased revenues from regulatory infrastructure program revenues at Atlanta Gas Light	15	33
(Decreased) increased revenues from usage and weather normalization at Virginia Natural Gas and Elizabethtown Gas	(6)	4
Increased (decreased) margin from gas storage carrying amounts at Atlanta Gas Light	2	(2)
Other	1	2
Increase in operating margin	**608**	**84**
Operating expenses		
Increased expenses for Nicor Gas as a result of the Nicor merger in December 2011 (1)	476	31
Increased depreciation expense due to additional assets being placed in service	8	10
Increased pension expenses primarily as a result of change in actuarial assumptions	7	2
Increased payroll and health benefit expenses	6	5
Increased outside services as a result of pipeline integrity programs at Atlanta Gas Light	6	1
Decreased incentive compensation costs as a result of not achieving corporate earnings	(7)	(19)
Decreased bad debt expenses as a result of warmer weather and lower natural gas prices	(5)	(4)
Increase in operating expenses	**491**	**26**
Increase in other income	**3**	**2**
EBIT - current year	**$532**	**$412**

(1) Includes additional accrual of $8 million for Nicor Gas PBR issue. See Note 11 for more information.

Retail Operations

Our retail operations segment, which consists of SouthStar and several businesses that provide energy-related products and services to retail markets, also is weather sensitive and uses a variety of hedging strategies, such as weather derivative instruments and other risk management tools, to partially mitigate potential weather impacts. During 2012, warmer-than-normal weather reduced our expected operating margin by $9 million.

In millions	**2012**	**2011**
EBIT - prior year	**$93**	**$103**
Operating margin		
Increased margin as a result of the Nicor merger in December 2011	76	5
Increase related to reduction of transportation and gas costs and higher retail price spreads, partially offset by unfavorable customer portfolio	10	3
Decreased average customer usage primarily due to warmer weather, net of weather derivatives	(10)	(15)
Change in LOCOM adjustment	1	(5)
Increased (decreased) operating margins for Florida, Ohio and interruptible customers	2	(2)
Other	-	(1)
Increase (decrease) in operating margin	**79**	**(15)**
Operating expenses		
Increased expenses as a result of the Nicor merger in December 2011	59	3
Decreased bad debt expenses as a result of lower natural gas prices and warmer weather	(5)	(3)
Decreased legal expense	0	(4)
Other	2	(1)
Increase (decrease) in operating expenses	**56**	**(5)**
EBIT - current year	**$116**	**$93**

Wholesale Services

Our wholesale services segment is involved in asset management and optimization, storage, transportation, producer and peaking services, natural gas supply, natural gas services and wholesale marketing. EBIT for our wholesale services segment is impacted by volatility in the natural gas market arising from a number of factors including weather fluctuations and changes in supply or demand for natural gas in different regions of the country.

In millions	**2012**	**2011**
EBIT - prior year	**$5**	**$49**
Operating margin		
Change in value of storage hedges as a result of changes in NYMEX natural gas prices	(23)	8
Change in value of transportation and forward commodity hedges from price movements related to natural gas transportation positions (1)	(11)	(9)
Change in commercial activity	5	(23)
Change in LOCOM adjustment, net of hedging recoveries	22	(24)
Decrease in operating margin	**(7)**	**(48)**
Operating expenses		
Increased (decreased) payroll, benefits and incentive compensation costs in 2012 due to higher expected operating revenues, as indicated in storage withdrawal schedule at December 31, 2012	4	(5)
Decreased other costs	(2)	0
Increase (decrease) in operating expenses	**2**	**(5)**
Increase (decrease) in other income	1	(1)
EBIT - current year	**$(3)**	**$5**

(1) 2011 amount excludes forward commodity hedge losses associated with counterparty bankruptcy and Marcellus take-away constraint losses.

Change in storage and transportation hedges Seasonal (storage) and geographical location (transportation) spreads continue to be significantly lower as compared to prior years and overall natural gas price volatility remained low during 2012. Storage hedge gains in 2012, 2011 and 2010, and gains from our transportation positions in 2011 and 2010 were primarily due to larger seasonal and transportation spreads at the time our storage and transportation positions were executed and the subsequent downward movement of natural gas prices and narrowing regional transportation spreads in 2011 and 2010. For 2012, losses in our transportation positions are the result of significant volatility during the fourth quarter of 2012 experienced at natural gas delivery points throughout the northeast corridor related to natural gas delivery constraints in the region. These losses are temporary and, based on current expectations, will be recovered in 2013 through 2015 (with the majority recognized in 2013) via the physical flow of natural gas and utilization of the contracted transportation capacity.

Change in Commercial activity The change in commercial activity was primarily due to losses in 2011 associated with constraints of natural gas purchased from producers in the Marcellus shale gas producing region and credit losses associated with a counterparty that filed for bankruptcy during 2011. Commercial activity in 2012 also was impacted by the abundance of natural gas supply due to shale production, reducing price volatility and transportation spreads. Additionally, 2012 was one of the warmest years in recorded history causing a reduction in customer demand and transportation spreads.

The following table indicates the components of wholesale services' operating margin for the periods presented.

In millions	2012	2011	2010
Commercial activity recognized	$43	$38	$61
(Loss) gain on transportation and forward commodity hedges	(3)	8	17
Gain on storage hedges	14	37	29
Inventory LOCOM adjustment, net of estimated current period recoveries	(4)	(26)	(2)
Operating margin	$50	$57	$105

For more information on Sequent's expected operating revenues from its storage inventory in 2013 and discussion of commercial activity, see description of the inventory roll-out schedule in Item 1 "Business."

Midstream Operations

Our midstream operations segment's primary activity is operating non-utility storage and pipeline facilities including the development, acquisition and operation of high-deliverability underground natural gas storage assets. For more information on our operating segments, see Item 1, "Business."

In millions	2012	2011
EBIT - prior year	**$9**	**$6**
Operating margin		
Increased margin from Central Valley Storage as a result of the Nicor merger in December 2011 primarily driven by firm revenues and hedge gains	8	0
Increased revenues primarily at Golden Triangle Storage as a result of Cavern 2 beginning commercial service in third quarter 2012	2	7
Decreased revenues at Jefferson Island as a result of lower subscription rates	(4)	(2)
Other – primarily increased revenues in 2012 related to entry into LNG and renewable gas markets	3	2
Increase in operating margin	**9**	**7**
Operating expenses		
Increased expense from Central Valley Storage as a result of the Nicor Merger in December 2011	7	0
Increased operating and depreciation expenses at Golden Triangle Storage as a result of Cavern 2 beginning commercial service in third quarter 2012	1	7
Increased expenses primarily related to entry into the LNG and renewable gas markets	4	0
Other - primarily lower project development costs	(2)	(3)
Increase in operating expenses	**10**	**4**
Increase in other income from equity interest in Horizon Pipeline as a result of the Nicor merger	**2**	**0**
EBIT - current year	**$10**	**$9**

Cargo Shipping

Our cargo shipping segment's primary activity is transporting containerized freight in the Bahamas and the Caribbean, a region that has historically been characterized by modest market growth and intense competition. Such shipments consist primarily of southbound cargo such as building materials, food and other necessities for developers, distributors and residents in the region, as well as tourist-related shipments intended for use in hotels and resorts, and on cruise ships. The balance of the cargo consists primarily of interisland shipments of consumer staples and northbound shipments of apparel, rum and agricultural products. Other related services such as inland transportation and cargo insurance are also provided within the cargo shipping segment.

Our cargo shipping segment also includes an equity investment in Triton, a cargo container leasing business. Triton is a full-service global leasing company and an owner-lessor of marine intermodal cargo containers. Profits and losses are generally allocated to investors capital accounts in proportion to their capital contributions. Our investment in Triton is accounted for under the equity method, and our share of earnings is reported within "Other Income" on our Consolidated Statements of Income. For more information about our investment in Triton, see Note 10 to our consolidated financial statements under Item 8 herein.

The cargo shipping business reported EBIT of $8 million for the year ended December 31, 2012, including $11 million EBIT from our investment in Triton, and immaterial EBIT for the period ending December 31, 2011, as it only reflected the 22 days following the close of our merger with Nicor.

Liquidity and Capital Resources

Overview The acquisition of natural gas and pipeline capacity, payment of dividends and funding of working capital needs 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. 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 with cash from operations are primarily satisfied with short-term borrowings under our commercial paper programs, which are supported by the AGL Credit Facility and the Nicor Gas 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 is focused on maintaining strong Consolidated Statements of Financial Position, ensuring ample cash resources and daily liquidity, accessing capital markets at favorable times as necessary, managing critical business risks and maintaining a balanced capital structure through the appropriate issuance of equity or long-term debt securities.

Our financing activities, including long-term and short-term debt and equity, are subject to customary approval or review by state and federal regulatory bodies, including the various commissions of the states in which we conduct business. Certain financing activities we undertake may also be subject to approval by state regulatory agencies. 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. Nicor Gas is restricted by regulation in the amount it can dividend or loan to affiliates and is not permitted to make money pool loans to affiliates. Dividends to AGL Resources are allowed only to the extent of Nicor Gas' retained earnings balance, which was $500 million at December 31, 2012.

We believe the amounts available to us under our senior notes, AGL Credit Facility and Nicor Gas Credit Facility, through the issuance of debt and equity securities, combined with cash provided by operating activities, will continue to allow us to meet our needs for working capital, pension contributions, capital expenditures, anticipated debt redemptions, interest payments on debt obligations, dividend payments, common share repurchases and other cash needs through the next several years. Our ability to satisfy our working capital requirements and our 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, and demand for, natural gas and operational risks.

As of December 31, 2012 and 2011, we had $80 million and $71 million, respectively, of cash and short and long-term investments on our Consolidated Statements of Financial Position that were generated from Tropical Shipping. This cash and the investments are not available for use by our other operations unless we repatriate a portion of Tropical Shipping's earnings in the form of a dividend that would be subject to a significant amount of United States income tax. See Note 12 to our consolidated financial statements under Item 8 herein for additional information on our income taxes.

We will continue to evaluate our need to increase available liquidity based on our view of working capital requirements, including the impact of changes in natural gas prices, liquidity requirements established by rating agencies and other factors. See Item 1A, "Risk Factors," for additional information on items that could impact our liquidity and capital resource requirements.

Credit Ratings Our borrowing costs and our ability to obtain adequate and cost-effective financing are directly impacted by our credit ratings, as well as the availability of financial markets. Credit ratings are important to our counterparties when we engage in certain transactions, including OTC derivatives. It is our long-term objective to maintain or improve our credit ratings in order to manage our existing financing costs 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. The rating agencies regularly review our performance, prospects and financial condition and reevaluate their ratings of our long-term debt and short-term borrowings, our corporate ratings and our ratings outlook. 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 and each rating should be evaluated independently of other ratings.

Factors we consider important in assessing our credit ratings include our Consolidated 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 or our stock price and have not entered into any agreements that would require us to issue equity based on credit ratings or other trigger events. As of December 31, 2012, if our credit rating had fallen below investment grade, we would have been required to provide collateral of $22 million to continue conducting business with certain customers. The following table summarizes our credit ratings as of December 31, 2012.

	AGL Resources			Nicor Gas		
	S&P	Moody's	Fitch	S&P	Moody's	Fitch
Corporate rating	BBB+	n/a	BBB+	BBB+	n/a	A
Commercial paper	A-2	P-2	F2	A-2	P-2	F1
Senior unsecured	BBB+	Baa1	BBB+	BBB+	A3	A+
Senior secured	n/a	n/a	n/a	A	A1	AA-
Ratings outlook	Stable	Stable	Stable	Stable	Stable	Stable

In December 2012, Fitch downgraded the corporate and senior unsecured credit ratings of AGL Resources from A- to BBB+. The key drivers for the downgrade of AGL Resources were increased debt relative to the rating category, low growth in the regulated segment and the challenging market environment for the unregulated businesses. There were no implications on our corporate funding or access to capital markets as a result of this downgrade, nor did it trigger any collateralization requirements under our corporate guarantees.

In December 2011, subsequent to the completion of our merger with Nicor, all three of the rating agencies reassessed their credit ratings for the post-merger company and its subsidiaries. At that time, S&P downgraded the corporate credit rating of AGL Resources from A- to BBB+, while downgrading the corporate credit rating of Nicor Gas from AA to BBB+. Moody's affirmed the senior unsecured and short-term ratings of the legacy subsidiaries of AGL Resources, while downgrading the senior unsecured rating of Nicor Gas from A2 to A3 and the commercial paper rating of Nicor Gas from P-1 to P-2. Fitch affirmed its ratings for both AGL Resources and Nicor Gas.

The primary reason for the 2011 downgrade for AGL Resources was the increased financial leverage resulting from the merger and the resulting weakening of our consolidated credit metrics. The downgrade of Nicor Gas was primarily an attempt to conform the Nicor Gas credit ratings to those of the subsidiaries of AGL Resources.

Our credit ratings depend largely on our financial performance, and a downgrade in our current ratings, particularly below investment grade, would increase our borrowing costs and could 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.

Default Provisions Our debt instruments and other financial obligations include provisions that, if not complied with, could require early payment or similar actions. Our credit facilities contain customary events of default, including, but not limited to, the failure to pay 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 facilities contain 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 facilities each include a financial covenant that requires us to maintain a ratio of total debt to total capitalization of no more than 70% at the end of any fiscal month. This ratio, as defined within our debt agreements, includes standby letters of credit, performance/surety bonds and excludes accumulated OCI items related to non-cash pension adjustments, other post-retirement benefits liability adjustments and accounting adjustments for cash flow hedges. Adjusting for these items, the following table contains our debt-to-capitalization ratios for the periods presented, which are within our required and targeted ranges.

	AGL Resources		**Nicor Gas**	
	December 31,		**December 31,**	
	2012	**2011**	**2012**	**2011**
Debt-to-capitalization ratio	58%	58%	55%	60%

We were in compliance with all of our debt provisions and covenants, both financial and non-financial, as of December 31, 2012 and 2011.

Our ratio of total debt to total capitalization, on a consolidated basis, 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 ratio of total debt to total capitalization 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. For more information on our default provisions see Note 8 to our consolidated financial statements under Item 8 herein. 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.

	December 31, 2012	2011
Short-term debt	16%	16%
Long-term debt	43	43
Total debt	59	59
Equity	41	41
Total capitalization	100%	100%

Cash Flows

The following table provides a summary of our operating, investing and financing cash flows for the last three years.

In millions	2012	2011	2010
Net cash provided by (used in):			
Operating activities	$1,003	$451	$526
Investing activities	(786)	(1,339)	(442)
Financing activities	(155)	933	(86)
Net increase (decrease) in cash and cash equivalents	62	45	(2)
Cash and cash equivalent at beginning of period	69	24	26
Cash and cash equivalent at end of period	$131	$69	$24

Cash Flow from Operating Activities We prepare our Consolidated Statements 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 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 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.

2012 compared to 2011 Our increased cash from operating activities was $1,003 million, an increase of $552 million or 122% from 2011. The increase was primarily related to the recovery of working capital from the companies acquired in the December 2011 merger with Nicor. Cash provided by operations changed $89 million in derivative financial instrument assets and liabilities primarily a result of the change in forward NYMEX prices at wholesale services year-over-year and $70 million driven by a decrease in Sequent's park and loan gas transactions due to lower volumes and decreased prices. Additionally, we had a $26 million increase in operating cash flow from Elizabethtown Gas' recoverable derivative position as a result of changes in forward NYMEX prices. These increases were partially offset by a decrease in recovery of working capital during 2012 as a result of warmer-than-normal weather. Our increased operating cash flow in 2012 was also impacted by a decrease in cash used for margin deposits of $94 million due to the change in cash collateral value on our hedged positions and a $121 million decrease in trade payables mainly due to lower natural gas prices and purchased volumes in 2012.

2011 compared to 2010 In 2011, our net cash flow provided from operating activities was $451 million, a decrease of $75 million or 14% from 2010. This decrease was primarily a result of merger-related expenses in 2011 and the payment of $22 million of Nicor deferred compensation plans and $12 million of Nicor financial advisor fees. Our gas and trade payables required $58 million more of cash compared to 2010, primarily related to our subsidiaries acquired as part of the Nicor merger. Additionally, we had a $69 million decrease in operating cash flow from loaned gas activities associated with park and loan gas transactions in part due to fewer opportunities resulting from a weakening of storage price differentials.

These decreases in our cash from operating activities were primarily due to Nicor Gas net inventory withdrawals of $89 million in the period after merger closing through December 31, 2011 and were partially offset by a $158 million increase in cash received from our inventories primarily driven by a lower average cost of gas inventory and lower volumes of gas inventory.

Cash Flow from Investing Activities The decrease in net cash used in investing activities was primarily a result of our $912 million payment for the cash portion of the purchase consideration, net of cash that was acquired in the Nicor merger in 2011. This was offset by an increase in PP&E expenditures of $355 million, the majority of which were within our distribution operations and midstream operations segments. Our estimated PP&E expenditures for 2013 and our actual PP&E expenditures incurred in 2012, 2011 and 2010 are shown within the following categories and are presented in the following table.

- **Distribution business** - primarily includes new construction and infrastructure improvements

- **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, SAVE at Virginia Natural Gas, and Elizabethtown Gas' utility infrastructure enhancements program
- **Natural gas storage** - underground natural gas storage at Golden Triangle Storage, Jefferson Island and Central Valley
- **Other** - primarily includes cargo shipping, information technology and building and leasehold improvements

In millions	**2013** (1)	**2012**	**2011** (2)	**2010**
Distribution business	$365	$371	$159	$159
Regulatory infrastructure programs	212	263	192	186
Natural gas storage	11	55	22	114
Other	106	93	54	51
Total	$694	$782	$427	$510

(1) Estimated PP&E expenditures.
(2) Only includes Nicor expenditures subsequent to the merger date of December 9, 2011.

Our PP&E expenditures were $782 million for the year ended December 31, 2012, compared to $427 million for the same period in 2011.The increase of $355 million, or 83% was primarily due to $188 million of PP&E expenditures at Nicor Gas and $31 million of PP&E expenditures at Central Valley, both of which were acquired through our merger with Nicor in December 2011. Additionally, capital expenditures increased $63 million for pipeline replacement projects, $21 million for i-SRP projects and $10 million for i-CGP projects at Atlanta Gas Light as well as $16 million for accelerated infrastructure replacement program projects at Virginia Natural Gas.

Our PP&E expenditures were $427 million for the year ended December 31, 2011, compared to $510 million for the same period in 2010. This decrease of $83 million, or 16%, was primarily due to a $98 million decrease in expenditures for the construction of the Golden Triangle Storage natural gas storage facility due to the completion of base infrastructure spending and completion of the first cavern. This was partially offset by capital expenditures of $13 million at Nicor Gas and $6 million at Central Valley that were incurred subsequent to merger closing.

Our estimated expenditures for 2013 include discretionary spending for capital projects principally within the distribution business, regulatory infrastructure programs, natural gas storage 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.

On December 6, 2012, we entered into a ten-year, $200 million 1.78% fixed-rate forward-starting interest rate swap to hedge any potential interest rate volatility prior to an anticipated issuance of senior notes during the second quarter 2013. We have designated the forward-starting interest rate swap, which will mature on the debt issuance date, as a cash flow hedge. On September 6, 2012, we settled our $250 million fixed-rate to floating-rate interest rate swap related to the $300 million outstanding 6.4% senior notes due in July 2016. This settlement resulted in our receipt of a $17 million cash payment.

As of December 31, 2012, our variable-rate debt was $1.5 billion, or 32%, of our total debt, compared to $1.7 billion, or 36%, as of December 31, 2011. The decrease was primarily due to working capital requirements in 2011. As of December 31, 2012, our commercial paper borrowings of $1.4 billion were 4% higher than the same time last year, primarily a result of higher working capital requirements. For more information on our debt, see Note 8 to our consolidated financial statements under Item 8 herein.

Our cash used in financing activities was $155 million in 2012 compared to cash provided of $933 million in 2011. The decrease in net cash flow provided by financing activities of $1,088 million was primarily due to our $1.3 billion of long-term debt issued and increased commercial paper borrowings million in 2011.

Merger Financing On December 9, 2011, we closed our merger with Nicor. The total value of the consideration paid to Nicor common shareholders was $2.5 billion. Upon closing the merger, we assumed the first mortgage bonds of Nicor Gas, which at December 31, 2012 and 2011 had principal balances totaling $500 million and maturity dates between 2016 and 2038. These bonds were recorded at their estimated fair value of $599 million on the date the merger closed. Additionally, we assumed $424 million in short-term debt upon closing the merger.

During 2011, we secured the permanent debt financing we used to pay the cash portion of the purchase consideration. This included approximately $200 million from our $500 million in senior notes that were issued in March 2011, $500 million in senior notes that were issued in September 2011, and $275 million in senior unsecured notes that were issued in the private placement market in October 2011.

Short-term Debt Our short-term debt as of December 31, 2012 was comprised of borrowings under our commercial paper programs and current portions of our senior notes and capital leases:

In millions	**Year-end balance outstanding** (1)	**Daily average balance outstanding** (2)	**Minimum balance outstanding** (2)	**Largest balance outstanding** (2)
Commercial paper - AGL Capital	$1,063	$791	$578	$1,093
Commercial paper - Nicor Gas	314	147	0	456
Current portion of long-term debt	225	167	15	240
Current portion of capital leases	1	1	1	2
Total short-term debt and current portion of long-term debt and capital leases	$1,603	$1,106	$594	$1,791

(1) As of December 31, 2012.
(2) The minimum and largest balances outstanding for each short-term debt instrument occurred at different times during the year and thus the total balances are not indicative of actual borrowings on any one day during the year.

The largest, minimum and daily average balances borrowed under our commercial paper programs are important when assessing the intra-period fluctuation of our short-term borrowings and potential liquidity risk. The fluctuations are due to our seasonal cash requirements.

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

On November 10, 2011, the existing AGL Credit Facility was amended to increase the available principal to $1.3 billion in support of the AGL Capital commercial paper program. On December 15, 2011, Nicor Gas entered into a $700 million revolving credit facility to support the Nicor Gas commercial paper program. The AGL Credit Facility and the Nicor Gas Credit Facility can be drawn upon to meet working capital and other general corporate needs. The interest rates payable on borrowings under these facilities are calculated either at the alternative base rate, plus an applicable margin, or LIBOR, plus an applicable interest margin. The applicable interest margin used in both interest rate calculations will vary according to AGL Capital's and Nicor Gas' current credit ratings. At December 31, 2012 and 2011, we had no outstanding borrowings under either of these facilities.

The timing of natural gas withdrawals is dependent on the weather and natural gas market conditions, both of which impact the price of natural gas. 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, we believe that we have sufficient liquidity to cover our working capital needs for the upcoming Heating Season.

The lenders under our credit facilities and lines of credit are major financial institutions with $2.2 billion of committed balances and all have investment grade credit ratings as of December 31, 2012. 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, 2012, and consisted of medium-term notes: Series A, Series B, and Series C, which we issued under an indenture during December 1989; senior notes; first mortgage bonds; and gas facility revenue bonds.

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.

	Issuance Date	**Amount** (in millions)	**Term** (in years)	**Interest rate**
Senior notes - Series A (1)	October 2011	$120	5	1.9%
Senior notes - Series B (1)	October 2011	$155	7	3.5%
Senior notes (1)	September 2011	$200	30	5.9%
Senior notes (1)	September 2011	$300	10	3.5%
Senior notes (2)	March 2011	$500	30	5.9%
Gas facility revenue bonds (3)	October 2010	$160	11 - 21	reset daily

(1) The net proceeds were used to pay a portion of the cash consideration and expenses incurred in connection with the Nicor merger.
(2) The net proceeds were used to repay our commercial paper and to repay our $300 million in senior notes that matured on January 14, 2011. The remaining proceeds were used to pay a portion of the cash consideration and expenses incurred in connection with the Nicor merger.
(3) We entered into new agreements with remarketing agents to resell the bonds to investors, and established new letters of credit to provide credit enhancement to the bonds.

Noncontrolling Interest We recorded cash distributions for SouthStar's dividend distributions to Piedmont of $14 million in 2012, $16 million in 2011 and $27 million in 2010 in our Consolidated Statements of Cash Flows as financing activities. The primary reason for the reduction in the distribution to Piedmont during the current year is due to decreased earnings for 2012.

Dividends on Common Stock Our common stock dividend payments were $203 million in 2012, $148 million in 2011 and $136 million in 2010. The increases were generally the result of the annual dividend increase of $0.04 per share for each of the last three years. However, as a result of the Nicor merger, AGL Resources shareholders of record as of the close of business on December 8, 2011, received a pro rata dividend of $0.0989 per share for the stub period, accruing from November 19, 2011 totaling $7 million. The dividend payments made in February 2012 were reduced by this stub period dividend. For information about restrictions on our ability to pay dividends on our common stock, see Note 9 to our consolidated financial statements under Item 8 herein.

Treasury Shares In February 2006, our Board of Directors authorized us to purchase up to 8 million treasury shares through our repurchase plan, which expired on January 31, 2011. This plan was used to offset shares issued under our employee and non-employee director incentive compensation plans and our dividend reinvestment and stock purchase plans. Stock purchases under this plan were made in the open market or in private transactions at times, and in amounts that we deemed appropriate.

For the year ended December 31, 2011, we purchased less than 0.1 million shares of our common stock at a weighted average cost of $36.25 per common share and an aggregate cost of $2 million. For the year ended December 31, 2010, we purchased 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. We held the purchased shares as treasury shares and accounted for them using the cost method. For the year ended December 31, 2012, we did not purchase any shares of our common stock. 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 AGL Credit Facility and Term Loan Facility financial covenants related to total debt to total capitalization. The debt securities will be guaranteed by AGL Resources.

On February 25, 2009, Nicor Gas filed a shelf registration with the SEC with a capacity of $225 million that expired in March 2012. Nicor Gas did not issue any first mortgage bonds under this shelf registration.

Off-balance sheet arrangements We have certain guarantees, as further described in Note 11 to our consolidated financial statements under Item 8 herein. We believe the likelihood of any such payment under these guarantees is remote. No liability has been recorded for these guarantees.

Contractual Obligations and Commitments We have incurred various contractual obligations and financial commitments in the normal course of business 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. The following table illustrates our expected future contractual obligation payments such as debt and lease agreements, and commitments and contingencies as of December 31, 2012.

In millions	Total	2013	2014	2015	2016	2017	2018 & thereafter
Recorded contractual obligations:							
Long-term debt (1)	$3,432	$226	$0	$200	$545	$22	$2,439
Short-term debt	1,377	1,377	0	0	0	0	0
Pipeline replacement program costs (2)	121	121	0	0	0	0	0
Environmental remediation liabilities (2)	444	57	62	77	56	40	152
Total	$5,374	$1,781	$62	$277	$601	$62	$2,591
Unrecorded contractual obligations and commitments (3) (8) (9):							
Pipeline charges, storage capacity and gas supply (4)	$2,233	$762	$470	$307	$138	$92	$464
Interest charges (5)	2,430	166	163	153	140	126	1,682
Operating leases (6)	210	32	25	23	21	19	90
Asset management agreements (7)	31	12	8	5	4	2	0
Standby letters of credit, performance / surety bonds (8)	35	29	6	0	0	0	0
Other	8	2	2	2	2	0	0
Total	$4,947	$1,003	$674	$490	$305	$239	$2,236

(1) Excludes the $90 million step up to fair value of first mortgage bonds, $18 million unamortized debt premium and $13 million interest rate swaps fair value adjustment. Includes current portion of long-term debt of $225 million, which matures in April 2013, and current portion of capital leases.
(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 amounts for Nicor Gas and SouthStar gas commodity purchase commitments of 52 Bcf at floating gas prices calculated using forward natural gas prices as of December 31, 2012, and is valued at $186 million. As we do for other subsidiaries, we provide guarantees to certain gas suppliers for SouthStar in support of payment obligations.
(5) Floating rate interest charges are calculated based on the interest rate as of December 31, 2012 and the maturity date of the underlying debt instrument. As of December 31, 2012, we have $53 million of accrued interest on our Consolidated Statements of Financial Position that will be paid in 2013.
(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. Our operating leases are primarily for real estate.
(7) Represent fixed-fee minimum payments for Sequent's affiliated asset management agreements.
(8) We provide guarantees to certain municipalities and other agencies and certain gas suppliers of SouthStar in support of payment obligations.
(9) Based on the current funding status of the plans, we are not required to make a minimum contribution to our pension plans in 2013.

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 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 other retirement 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 other retirement costs we are responsible for under the terms of our plan and minimum funding required by state regulatory commissions.

The state regulatory commissions in all of our jurisdictions, except Illinois, have phase-ins that defer a portion of the retirement benefit expenses for retirement plans other than pensions for future recovery. We recorded a regulatory asset for these future recoveries of $215 million as of December 31, 2012 and $291 million as of December 31, 2011. In addition, we recorded a regulatory liability of $3 million as of December 31, 2012 and $19 million as of December 31, 2011 for our expected expenses under the AGL Postretirement Plan. In Illinois, all accrued retirement plan expenses are recovered through base rates. See Note 6 to our consolidated financial statements under Item 8 herein for additional information about our pension and other retirement plans.

In 2012, we contributed $40 million to our qualified pension plans. In 2011, we contributed $56 million to these qualified pension plans. Effective December 31, 2012, we have merged the NUI Pension and Nicor Pension plans into the AGL Pension plan and based on the estimated funded status of the merged AGL Pension plan, we would not be required to make a minimum required contribution to the plan in 2013. We may make contributions in 2013 in order to preserve the current level of benefits under the plan 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 primarily due to the need to make estimates about the effects of matters that are inherently uncertain. Actual results could differ from those estimates. We frequently reevaluate our judgments and estimates that are based upon historical experience and various other assumptions that we believe to be reasonable under the circumstances.

The following is a summary of our most critical accounting policies, which represent those that may involve a higher degree of uncertainty, judgment and complexity: Environmental Remediation Liabilities, Derivatives and Hedging Activities, Impairment of Goodwill and Long-Lived Assets, including Intangible Assets, Contingencies, Pension and Other Retirement Plans and Income Taxes. Our significant accounting policies are described in Note 2 to our consolidated financial statements under Item 8 herein.

Environmental Remediation Liabilities

We are subject to legislation and regulation by federal, state and local authorities with respect to environmental matters. We previously owned and operated a number of MGP sites at which MPG residuals 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 when such estimates cannot be made, which is generally the case when remediation has not commenced or during the early years of a site investigation and remediation effort. For those elements of the program where we cannot perform engineering estimates, there remains considerable variability in future cost estimates. Accordingly, we have established a probabilistic model to determine a range of potential expenditures to remediate and monitor our former operating sites. We cannot at this time identify any single number within this range as a better estimate of likely future costs, and we generally have recorded the low end of the range for our probabilistic cost estimates.

We cannot perform precise engineering soil and groundwater cleanup estimates for certain of our former MGP sites. As we 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 and the liabilities may increase as estimates are refined and remediation efforts proceed. These estimates contain various engineering assumptions, which we refine and update on an ongoing basis. We completed our probabilistic models and engineering estimates for our sites in Illinois during 2012, which primarily contributed to the $117 million increase from the amount recorded at December 31, 2011. These costs are recoverable from our customers as they are paid and, accordingly, we have recorded a regulatory asset associated with the recorded liabilities. See Note 11 of our consolidated financial statements for more information on our ERC. We presently report estimates of future remediation costs on an undiscounted basis.

We have identified 26 former operating sites in Illinois where Nicor Gas or its predecessors owned or operated all or part of these sites. Most of these sites are not presently owned by us. In accordance with Illinois Commission authorization, we have been recovering, and expect to continue to recover, these costs from our customers, subject to annual prudence reviews.

In Georgia and Florida, we have confirmed 13 former MGP sites where Atlanta Gas Light, or its predecessors, 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 are no cost recovery mechanisms for the environmental remediation sites in North Carolina.

The following table provides more information on our former operating sites:

In millions	Probabilistic model cost estimates	Engineering estimates	Amount recorded	Expected costs over next twelve months
Illinois	$193 - $439	$50	$243	$32
New Jersey	116 - 203	6	122	13
Georgia and Florida	53 - 106	12	68	4
North Carolina	n/a	11	11	8
Total	$362 - $748	$79	$444	$57

Beyond 2013, 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 11 to our consolidated financial statements under Item 8 herein.

Derivatives and Hedging Activities

The authoritative guidance to determine whether a contract meets the definition of a derivative instrument, contains an embedded derivative requiring bifurcation, or qualifies for hedge accounting treatment is numerous and complex. The treatment of a single contract may vary from period to period depending upon accounting elections, changes in our assessment of the likelihood of future hedged transactions or new interpretations of accounting guidance. As a result, judgment is required in determining the appropriate accounting treatment. In addition, the estimated fair value of derivative instruments may change significantly from period to period depending upon market conditions, and changes in hedge effectiveness may impact the accounting treatment.

The authoritative guidance related to derivatives and hedging requires that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the Consolidated 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 normal sale, it is exempted from the fair value accounting treatment and is, instead, 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 derivatives' fair value are recognized concurrently in earnings unless specific hedge accounting criteria are met. If the derivatives meet those criteria, the guidance allows a derivatives' 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.

Nicor Gas and Elizabethtown Gas utilize derivative instruments for the purchase of natural gas for customers. These derivatives are reflected at fair value and are not designated as hedges. Realized gains or losses on such instruments are included in the cost of gas delivered and are passed through directly to customers, subject to review by the applicable state regulatory commissions, and therefore have no direct impact on earnings. Unrealized changes in the fair value of these derivative instruments are deferred as regulatory assets or liabilities.

We use derivative 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 instruments used to manage our exposure to 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.

Additionally, as required by the authoritative guidance, we are required to classify our derivative 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. 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 instrument assets of $144 million at December 31, 2012 and $288 million at December 31, 2011. Additionally, we have recorded derivative liabilities of $38 million at December 31, 2012 and $110 million at December 31, 2011. We recorded gains on our Consolidated Statements of Income of $10 million in 2012 and losses of $24 million in 2011 and $46 million in 2010.

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, results of operations and cash flows. Our derivative and hedging activities are described in further detail in Note 2 to our consolidated financial statements under Item 8 herein and Item 1, "Business."

Impairment of Goodwill and Long-Lived Assets, including Intangible Assets

Goodwill We do not amortize our goodwill, but test it for impairment at the reporting unit level during the fourth fiscal quarter 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. A reporting unit is the operating segment, or a business one level below the operating segment (a component), if discrete financial information is prepared and regularly reviewed by management. Components are aggregated if they have similar economic characteristics.

As part of our impairment test, an initial assessment is made by comparing the fair value of a reporting unit with its carrying value, including goodwill. If the fair value is less than the carrying value, an impairment is indicated, and we must perform a second test to quantify the amount of the impairment. In the second test, we calculate the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value determined in step one of the assessment. If the carrying value of the goodwill exceeds the implied fair value of the goodwill, we record an impairment charge.

To estimate the fair value of our reporting units, we use two generally accepted valuation approaches, an income approach and a market approach, using assumptions consistent with a market participant's perspective.

Under the income approach, fair value is determined based upon the present value of estimated future cash flows discounted at an appropriate risk-adjusted rate. These forecasts contain a degree of uncertainty, and changes in these projected cash flows could significantly increase or decrease the fair value of a reporting unit. For the regulated reporting units, a fair recovery of and return on costs prudently incurred to serve customers is assumed. An unfavorable outcome in a rate case could cause the fair value of these reporting units to decrease. Key assumptions used in the income approach included return on equity for the regulated reporting units, long-term growth rates used to determine terminal values at the end of the discrete forecast period, and discount rates. The discount rate is applied to estimated future cash flows and is one of the most significant assumptions used to determine fair value under the income approach. As interest rates rise, the calculated fair values will decrease. The terminal growth rate is based on a combination of historical and forecasted statistics for real gross domestic product and personal income for each utility service area.

Under the market approach, fair value is determined by applying market multiples to forecasted cash flows. This method uses metrics from similar publicly traded companies in the same industry to determine how much a knowledgeable investor in the marketplace would be willing to pay for an investment in a similar company.

The goodwill impairment testing develops a baseline test and performs a sensitivity analysis to calculate a reasonable valuation range. The sensitivities are derived by altering those assumptions which are subjective in nature and inherent to a discounted cash flows calculation. We weight the results of the two valuation approaches to estimate the fair value of each reporting unit.

Our goodwill impairment analysis for the year ended December 31, 2012 indicated that the estimated fair value of all but one of our reporting units with goodwill was in excess of the carrying value by approximately 20% to over 500%, and are not at risk of failing step one of the impairment test. The estimated fair value of a reporting unit within our midstream operations segment, with $14 million of goodwill, exceeded its carrying value by less than 10%. The significant assumptions that drive the estimated fair value are projected cash flows, current and future rates for contracted capacity, growth rates, weighted average cost of capital and market multiples. Due to the subjectivity of these assumptions, we cannot provide assurance that future analyses will not result in impairment as a future impairment depends on market and economic factors affecting fair value.

Long-Lived Assets We depreciate/amortize our long-lived assets, including intangible assets, over their useful lives. Currently, we have no indefinite-lived intangible assets. We assess these long-lived assets, for impairment whenever events or changes in circumstances indicate that an asset's carrying amount may not be recoverable. When such events or circumstances are present, we assess the recoverability of long-lived assets by determining whether the carrying value will be recovered through the expected future cash flows. An impairment is indicated if the carrying amount of a long-lived asset exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If an impairment is indicated, we record an impairment loss equal to the difference between the carrying value and the fair value of the long-lived asset.

We determined that there were no long-lived asset impairments in 2012; however, if our storage facilities within midstream operations experiences further natural gas price declines or a prolonged slow recovery, future analyses may result in an impairment of long-lived assets. If subscription rates and subscribed volumes decline, the estimated future cash flows will decrease from our current estimates. As of December 31, 2012, we estimate that approximately 15% of our future cash flows will be received over the next 10 years, an additional 20% over the next 10 years and approximately 65% in periods thereafter over the remaining useful lives of our storage facilities.

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 11 to our consolidated financial statements under Item 8 herein.

Pension and Other Retirement Plans

Effective as of December 31, 2012, the Employees' Retirement Plan of NUI Corporation (NUI Plan), and the Nicor Companies Pension and Retirement Plan (Nicor Plan) were merged with and into the AGL Resources Inc. Retirement Plan (AGL Plan). Our pension and other retirement 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 retirement plan costs and liabilities and update them when appropriate. The critical actuarial assumptions used to develop the required estimates for our pension and other retirement plans include the following key factors:

- assumed discount rates
- expected return on plan assets
- the market value of plan assets
- assumed mortality table
- assumed health care costs
- assumed compensation increases
- assumed rates of retirement
- assumed rates of termination

The discount rate is utilized in calculating the actuarial present value of our pension and other retirement obligations and our annual net pension and other retirement costs. When establishing our discount rate, with the assistance of our actuaries, we consider high-grade bond indices in developing a single equivalent discount rate for all of our plans. As of December 31, 2012, the single equivalent discount rate is derived by applying the appropriate spot rates based on high quality (AA or better) corporate bonds that have a yield higher than the regression mean yield curve, to the forecasted future cash flows in each year for each plan.

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 other retirement plans costs. 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 or less than the assumed rate, that year's annual pension or other retirement plan cost is not affected; rather, this gain or loss reduces or increases future pension or other retirement plan costs.

Equity market performance and corporate bond rates have a significant effect on our reported results. For the AGL pension plan, market performance affects 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 smoothing weighted average methodology. Gains and losses on plan assets are spread through the MRVPA based on the five-year smoothing weighted average methodology, which affects the expected return on plan assets component of pension expense.

In addition, differences between actuarial assumptions and actual plan experience 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 the AGL pension plan. If necessary, the excess is amortized over the average remaining service period of active employees.

During 2012, we recorded net periodic benefit costs of $53 million (net of capitalization) related to our defined pension and other retirement benefit plans. We estimate that in 2013, we will record net periodic pension and other retirement benefit costs in the range of $56 million to $63 million (net of capitalization), a $3 million to $10 million increase compared to 2012. Approximately $1 million to $2 million (net of capitalization) of the increase relates to the Nicor Gas retirement plans, which were acquired through the merger with Nicor. Accordingly, excluding the impacts of the additional costs from the Nicor Gas retirement plans, we anticipate that our net periodic pension and other retirement benefit costs will increase by $2 million to $8 million in 2013. Nicor Gas had recorded $19 million in net periodic benefit costs in 2011 prior to the completion of the merger. In determining our estimated expenses for 2013, our actuarial consultant assumed the following expected return on plan assets and discount rates:

	Pension plans	Other retirement plans
Discount rate	4.15%	3.95%
Expected return on plan assets	7.75%	7.75%

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 other retirement plans while holding all other assumptions constant:

		In millions	
Actuarial assumptions	**Percentage-point change in assumption**	**Increase (decrease) in PBO/ APBO**	**Increase (decrease) in cost**
Expected long-term return on plan assets	+/- 1%	$- / -	$(8) / 8
Discount rate	+/- 1%	(170) / 190	(15) / 15

See Note 4 and Note 6 to our consolidated financial statements under Item 8 herein for additional information on our pension and other retirement plans.

Income Taxes

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 account for income taxes in accordance with authoritative guidance, 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 allowance if it is more likely than not that some or all of the deferred tax assets will not be realized.

Deferred tax liabilities are 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.

A deferred income tax liability is not recorded on undistributed foreign earnings that are expected, in our judgment, to be indefinitely reinvested offshore. We consider, among other factors, actual cash investments offshore as well as projected cash requirements in making this determination. Changes in our investment or repatriation plans or circumstances could result in a different deferred income tax liability.

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 audits 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 reported.

We had a $22 million valuation allowance on $197 million of deferred tax assets as of December 31, 2012, reflecting the expectation that most of these assets will be realized. Our gross long-term deferred tax liability totaled $1,763 million at December 31, 2012. See Note 12 to our consolidated financial statements under Item 8 herein for additional information on our taxes.

We are required 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.

Additionally, we recognize accrued interest related to uncertain tax positions in interest expense, and penalties in operating expense in the Consolidated Statements of Income. As of December 31, 2012, we did not have a liability recorded for payment of interest and penalties associated with uncertain tax positions.

Accounting Developments

On December 16, 2011, the FASB issued authoritative guidance related to disclosures about offsetting assets and liabilities. The guidance requires disclosure about the effect of the offsetting of financial instruments, either in the financial statements or under netting arrangements with counterparties. On January 9, 2013, the FASB decided that the scope of this new disclosure requirement will be limited to derivative instruments carried at fair value. This guidance will be effective for us beginning January 1, 2013 and will not impact our consolidated financial statements.

On July 27, 2012, the FASB issued authoritative guidance related to the testing of indefinite-lived intangible assets for impairment. The guidance provides us with the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more-likely-than-not that the indefinite-lived asset is impaired. If, after assessing the total events or circumstances, we determine that it is not more-likely-than-not that the indefinite-lived asset is impaired, then we are not required to take further action. However, if we conclude otherwise, then we are required to determine the fair value of the indefinite-lived intangible asset and perform the quantitative impairment test by comparing the fair value with the carrying amount. The guidance also gives us the option to bypass the qualitative assessment for any period and proceed directly to performing the quantitative impairment test and resume performing the qualitative assessment in any subsequent period. This guidance will be effective for us beginning January 1, 2013 and will not have a material impact on our consolidated financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to risks associated with natural gas prices, interest rates, credit and fuel prices. Natural gas price risk results from changes in the fair value of natural gas. Interest rate risk is caused by fluctuations in interest rates related to 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. Fuel price risk, primarily in our cargo shipping segment, is a product of the fluctuation in fuel prices; however, this risk is partially reduced through fuel surcharges. Our use of derivative instruments is governed by a risk management policy, approved and monitored by our Risk Management Committee (RMC), which prohibits the use of derivatives for speculative purposes.

Our 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

Distribution Operations 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 has no natural gas price risk.

Nicor Gas and Elizabethtown Gas enter into derivative instruments to hedge the impact of market fluctuations in natural gas prices for customers. These derivatives are reflected at fair value and are not designated as hedges. Realized gains or losses on such instruments are included in the cost of gas delivered and are passed through directly to customers and therefore have no direct impact on earnings. Realized and unrealized changes in the fair value of these derivative instruments are deferred as regulatory assets or liabilities until recovered from or credited to our customers.

Retail Operations We routinely utilize various types of derivative 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. We use these hedging instruments to substantially lock in economic margins (as spreads between wholesale and retail natural gas prices widen between periods) and thereby minimize our exposure to declining operating margins.

Wholesale Services We routinely use various types of derivative 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.

Midstream Operations We use derivative instruments to reduce our exposure to the risk of changes in the price of natural gas that will be purchased in future periods for pad gas, conditioning gas and additional volumes of gas used to de-water our caverns (de-water gas) during the construction of storage facilities. Pad gas includes volumes of non-working natural gas used to maintain the operational integrity of the caverns. Conditioning gas is used to ready a field for use and will be sold in connection with placing the storage facility into service. 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 instruments for asset optimization purposes.

Consolidated The following tables include the fair values and average values of our consolidated derivative instruments as of the dates indicated. We base the average values on monthly averages for the 12 months ended December 31, 2012 and 2011.

	Derivative instruments average values (1) at December 31,	
In millions	**2012**	**2011**
Asset	$208	$184
Liability	101	76

(1) Excludes cash collateral amounts.

	Derivative instruments fair values netted with cash collateral at December 31,	
In millions	**2012**	**2011**
Asset	$144	$288
Liability	39	110

The following table illustrates the change in the net fair value of our derivative instruments during the twelve months ended December 31, 2012, 2011 and 2010, and provides detail of the net fair value of contracts outstanding as of December 31, 2012, 2011 and 2010.

In millions	**2012**	**2011**	**2010**
Net fair value of derivative instruments outstanding at beginning of period	$31	$55	$110
Derivative instruments realized or otherwise settled during period	(61)	(74)	(117)
Net fair value of derivative instruments acquired during period	0	(5)	0
Change in net fair value of derivative instruments	66	55	62
Net fair value of derivative instruments outstanding at end of period	36	31	55
Netting of cash collateral	69	147	105
Cash collateral and net fair value of derivative instruments outstanding at end of period (1)	$105	$178	$160

(1) Net fair value of derivative instruments outstanding includes $4 million premium and associated intrinsic value at December 31, 2012, $3 million at December 31, 2011 and less than $1 million at December 31, 2010 associated with weather derivatives.

The sources of our net fair value at December 31, 2012, are as follows.

In millions	**Prices actively quoted (Level 1)** (1)	**Significant other observable inputs (Level 2)** (2)
Mature through 2013	$(20)	$61
Mature 2014 - 2015	(12)	7
Mature 2016 - 2018	(2)	2
Total derivative instruments (3)	$(34)	$70

(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. Our VaR is determined on a 95% confidence interval and a 1-day holding period. In simple terms, this means that 95% of the time, the risk of loss from a portfolio of positions is expected to be less than or equal to the amount of VaR calculated.

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, 2012, 2011 and 2010 were less than $0.1 million and Sequent had the following VaRs.

In millions	2012	2011	2010
Period end	$1.8	$2.2	$1.6
12-month average	2.0	1.6	1.3
High	4.8	3.1	3.0
Low	1.1	0.8	0.7

Fuel Price Risk

Cargo Shipping Tropical Shipping's objective is to reduce its exposure to higher fuel costs through fuel surcharges. However, these fuel surcharges do not entirely remove our risk in periods of increasing fuel prices and volatility, or increased competition. An increase of 10% in Tropical Shipping's average cost per gallon for vessel fuel results in an additional $6 million in annual fuel expense. The aforementioned fuel surcharges would be implemented to reduce the impact of the increased fuel expense.

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 $1.5 billion of variable-rate debt outstanding at December 31, 2012, a 100 basis point change in market interest rates would have resulted in an increase in pre-tax interest expense of $15 million on an annualized basis.

On December 6, 2012, we entered into a ten-year, $200 million 1.78% fixed-rate forward-starting interest rate swap to hedge any potential interest rate volatility prior to an anticipated issuance of senior notes during the second quarter 2013. We anticipate issuing approximately $500 million to $600 million of senior notes in the first half of 2013. As we have only hedged $200 million of the anticipated offering, the remainder is subject to risk of increases in near-term interest rates. We have designated the forward-starting interest rate swap, which will mature on the debt issuance date, as a cash flow hedge.

In May 2011, we entered into interest rate swaps related to the $300 million outstanding of 6.4% senior notes due in July 2016. These interest rate swaps effectively converted $250 million from a fixed rate to a variable rate obligation. On September 6, 2012 we settled this $250 million interest rate swap, which resulted in our receipt of a $17 million cash payment that is classified as a financing activity in the Consolidated Statements of Cash Flows.

Interest rate swaps help us achieve our desired mix of variable to fixed rate debt (i.e. variable debt target of 20% to 45% of total debt). The gain or loss on the interest rate swaps designated as cash flow hedges is generally deferred in accumulated OCI until settlement, at which point it is amortized to interest expense over the life of the related debt. For additional information, see Note 5 to our consolidated financial statements under Item 8 herein.

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 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 2012, the four largest Marketers based on customer count accounted for approximately 17% of our consolidated operating margin and 22% of distribution operations' operating margin.

Several factors are designed to mitigate our risks from the increased concentration of credit that has resulted from deregulation. In addition to the security support described above, Atlanta Gas Light bills intrastate delivery service to Marketers in advance rather than in arrears. We accept credit support in the form of cash deposits, letters of credit/surety bonds from acceptable issuers and corporate guarantees from investment-grade entities. The RMC reviews on a monthly basis the adequacy of credit support coverage, credit rating profiles of credit support providers and payment status of each Marketer. We believe that adequate policies and procedures have been put in place to properly quantify, manage and report on Atlanta Gas Light's credit risk exposure to Marketers.

Atlanta Gas Light also faces potential credit risk in connection with assignments of interstate pipeline transportation and storage capacity to Marketers. Although Atlanta Gas Light assigns this capacity to Marketers, in the event that a Marketer fails to pay the interstate pipelines for the capacity, the interstate pipelines would in all likelihood seek repayment from Atlanta Gas Light.

Our gas distribution businesses offer options to help customers manage their bills, such as energy assistance programs for low-income customers and a budget payment plan that spreads gas bills more evenly throughout the year. Customer credit risk has been substantially mitigated at Nicor Gas by the bad debt rider approved by the Illinois Commission on February 2, 2010, which provides for the recovery from (or refund to) customers of the difference between Nicor Gas' actual bad debt experience on an annual basis and the benchmark bad debt expense included in its rates for the respective year. For Virginia Natural Gas and Chattanooga Gas, we are allowed to recover the gas portion of bad debt write-offs through their gas recovery mechanisms.

Nicor Gas faces potential credit risk in connection with its natural gas supply sales and procurement activities to the extent a counterparty defaults on a contract to pay for or deliver at agreed-upon terms and conditions. To manage this risk, Nicor Gas maintains credit policies to determine and monitor the creditworthiness of its counterparties. In doing so, Nicor Gas seeks guarantees or collateral, in the form of cash or letters of credit, which limits its exposure to any individual counterparty and enters into netting arrangements to mitigate counterparty credit risk.

Certain of our derivative instruments contain 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. As of December 31, 2012 for agreements with such features, our distribution operations derivative instruments with liability fair values totaled $11 million, for which we had posted no collateral to our counterparties. If it was assumed that we had to post the maximum contractually specified collateral or settle the liability, we would have been required to pay $11 million at December 31, 2012.

Retail Operations We obtain credit scores for our firm residential and small commercial customers using a national credit reporting agency, enrolling only those customers that meet or exceed our credit threshold. We consider potential interruptible and large commercial customers based on reviews of publicly available financial statements and commercially available credit reports. Prior to entering into a physical transaction, we also assign 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 We have established credit policies to determine and monitor the creditworthiness of counterparties, as well as the quality of pledged collateral. We also utilize master netting agreements whenever possible to mitigate exposure to counterparty credit risk. When we are engaged in more than one outstanding derivative transaction with the same counterparty and we also have a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of our credit risk. We also use other netting agreements with certain counterparties with whom we conduct significant transactions. Master netting agreements enable us to net certain assets and liabilities by counterparty. We also net across product lines and against cash collateral, provided the master netting and cash collateral agreements include such provisions.

Additionally, we may require counterparties to pledge additional collateral when deemed necessary. We conduct credit evaluations and obtain appropriate internal approvals for a 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, we require credit enhancements by way of guaranty, cash deposit or letter of credit for transaction counterparties that do not have investment grade ratings.

We have a concentration of credit risk as measured by our 30-day receivable exposure plus forward exposure. As of December 31, 2012, excluding $10 million of customer deposits, our top 20 counterparties represented approximately 50% of the total counterparty exposure of $420 million.

As of December 31, 2012, our counterparties, or the counterparties' guarantors, had a weighted average S&P equivalent credit rating of A-, which is an improvement from 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. The following table shows our third-party natural gas contracts receivable and payable positions:

	As of December 31,			
	Gross receivables		Gross payables	
In millions	2012	2011	2012	2011
Netting agreements in place:				
Counterparty is investment grade	$485	$395	$282	$255
Counterparty is non-investment grade	9	23	13	47
Counterparty has no external rating	175	184	315	288
No netting agreements in place:				
Counterparty is investment grade	7	4	1	0
Counterparty has no external rating	1	1	0	0
Amount recorded on Consolidated Statements of Financial Position	$677	$607	$611	$590

We have 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, we would need to post collateral to continue transacting business with some of our counterparties. If such collateral were not posted, our 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 with our counterparties would have totaled $11 million at December 31, 2012, which would not have a material impact to our consolidated results of operations, cash flows or financial condition.

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, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 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, 2012, 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, GA
February 6, 2013

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, 2012, 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 6, 2013

/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

AGL RESOURCES INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION - ASSETS

In millions	As of December 31, 2012	2011
Current assets		
Cash and cash equivalents	$131	$69
Short-term investments	58	53
Receivables		
Energy marketing receivables	677	607
Gas	362	364
Unbilled revenues	235	216
Other	89	112
Less allowance for uncollectible accounts	28	15
Total receivables, net	1,335	1,284
Inventories		
Natural gas stored underground	662	702
Other	46	48
Total inventories	708	750
Regulatory assets	145	131
Prepaid expenses	141	164
Derivative instruments	130	226
Other current assets	20	69
Total current assets	2,668	2,746
Long-term assets and other deferred debits		
Property, plant and equipment	10,478	9,779
Less accumulated depreciation	2,131	1,879
Property, plant and equipment, net	8,347	7,900
Goodwill	1,837	1,813
Regulatory assets	944	1,079
Long-term investments	136	128
Intangible assets	96	105
Derivative instruments	14	62
Other	99	80
Total long-term assets and other deferred debits	11,473	11,167
Total assets	$14,141	$13,913

See Notes to Consolidated Financial Statements.

AGL RESOURCES INC. AND SUBISIDIARIES
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION - LIABILITIES AND EQUITY

In millions, except share amounts	As of December 31, 2012	2011
Current liabilities		
Short-term debt	$1,377	$1,321
Energy marketing trade payable	611	590
Accounts payable - trade	334	294
Current portion of long-term debt and capital leases	226	17
Regulatory liabilities	161	112
Customer credit balances and deposits	143	152
Accrued regulatory infrastructure program costs	121	131
Accrued environmental remediation liabilities	57	37
Accrued taxes	53	49
Accrued interest	53	61
Accrued wages and salaries	34	52
Derivative instruments	33	99
Other current liabilities	135	169
Total current liabilities	3,338	3,084
Long-term liabilities and other deferred credits		
Long-term debt	3,327	3,561
Accumulated deferred income taxes	1,588	1,445
Regulatory liabilities	1,477	1,405
Accrued environmental remediation liabilities	387	290
Accrued other retirement benefit costs	268	320
Accrued pension obligations	240	238
Derivative instruments	6	11
Accrued regulatory infrastructure program costs	0	145
Other long-term liabilities and other deferred credits	75	75
Total long-term liabilities and other deferred credits	7,368	7,490
Total liabilities and other deferred credits	10,706	10,574
Commitments, guarantees and contingencies (see Note 11)		
Equity		
Common shareholders' equity		
Common stock, $5 par value; 750,000,000 shares authorized; outstanding: 117,855,075 shares at December 31, 2012 and 117,044,803 shares at December 31, 2011	590	586
Additional paid in capital	2,014	1,989
Retained earnings	1,035	967
Accumulated other comprehensive loss	(218)	(217)
Treasury shares, at cost: 216,523 shares at December 31, 2012 and 189,000 shares at December 31, 2011	(8)	(7)
Total common shareholders' equity	3,413	3,318
Noncontrolling interest	22	21
Total equity	3,435	3,339
Total liabilities and equity	$14,141	$13,913

See Notes to Consolidated Financial Statements.

AGL RESOURCES INC AND SUBISIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

	Years ended December 31,		
In millions, except per share amounts	**2012**	**2011**	**2010**
Operating revenues (includes revenue taxes of $86 for 2012, $9 for 2011 and $0 for 2010)	$3,922	$2,338	$2,373
Operating expenses			
Cost of goods sold	1,791	1,097	1,164
Operation and maintenance	921	501	497
Depreciation and amortization	415	186	160
Nicor merger expenses	20	57	6
Taxes other than income taxes	165	57	46
Total operating expenses	3,312	1,898	1,873
Operating income	610	440	500
Other income (expenses), net	24	7	(1)
Interest expenses, net	(184)	(136)	(109)
Total other expense	(160)	(129)	(110)
Earnings before income taxes	450	311	390
Income tax expenses	164	125	140
Net income	286	186	250
Less net income attributable to the noncontrolling interest	15	14	16
Net income attributable to AGL Resources Inc.	$271	$172	$234
Per common share data			
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	$2.32	$2.14	$3.02
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	$2.31	$2.12	$3.00
Cash dividends declared per common share	$1.74	$1.90	$1.76
Weighted average number of common shares outstanding			
Basic	117.0	80.4	77.4
Diluted	117.5	80.9	77.8

See Notes to Consolidated Financial Statements.

AGL RESOURCES INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

In millions	Years Ended December 31, 2012	2011	2010
Net income	$286	$186	$250
Other comprehensive loss, net of tax			
Retirement benefit plans			
Actuarial loss arising during the period (net of income tax of $16, $47 and $22)	(17)	(71)	(32)
Prior service costs arising during the period (net of income tax of $1)	1	0	0
Reclassification of losses to net benefit cost (net of income tax of $9, $7 and $5)	13	9	7
Reclassification of prior service costs to net benefit cost (net of income tax of $2, $3 and $3)	(2)	(3)	(3)
Retirement benefit plans	(5)	(65)	(28)
Cash flow hedges, net of tax			
Net derivative instrument gains (losses) arising during the period (net of income tax of $0, $3 and $7)	1	(6)	(15)
Reclassification of realized derivative losses to net income (net of income tax of $3, $2 and $6)	3	4	11
Cash flow hedges, net	4	(2)	(4)
Other comprehensive loss, net of tax	(1)	(67)	(32)
Comprehensive income	285	119	218
Less comprehensive income attributable to noncontrolling interest	15	14	17
Comprehensive income attributable to AGL Resources Inc.	$270	$105	$201

See Notes to Consolidated Financial Statements.

AGL RESOURCES INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY

	AGL Resources Inc. Shareholders								
In millions, except per share amounts	Common stock Shares	Common stock Amount	Additional paid-in-capital	Retained Earnings	Accumulated other comprehensive Loss	Treasury shares	Noncontrolling interest	Total
As of December 31, 2009	77.5	$390	$679	$848	$(116)	$(21)	$39	$1,819
Net income	-	-	-	234	-	-	16	250
Other comprehensive (loss) income	-	-	-	-	(33)	-	1	(32)
Dividends on common stock ($1.76 per share)	-	-	-	(136)	-	-	-	(136)
Purchase of additional 15% ownership interest in SouthStar	-	-	(51)	-	(1)	-	(6)	(58)
Distributions to noncontrolling interests	-	-	-	-	-	-	(27)	(27)
Purchase of treasury shares	(0.2)	-	-	-	-	(7)	-	(7)
Issuance of treasury shares	0.4	-	(1)	(2)	-	18	-	15
Stock-based compensation expense, net of tax	-	-	8	-	-	1	-	9
Stock granted, share-based compensation, net of forfeitures	-	-	(7)	-	-	-	-	(7)
Stock issued, dividend reinvestment plan	0.2	1	2	(1)	-	7	-	9
Stock issued, share-based compensation, net of forfeitures	0.1	-	1	-	-	-	-	1
As of December 31, 2010	78.0	$391	$631	$943	$(150)	$(2)	$23	$1,836
Net income	-	-	-	172	-	-	14	186
Other comprehensive loss	-	-	-	-	(67)	-	-	(67)
Dividends on common stock ($1.90 per share)	-	-	-	(148)	-	-	-	(148)
Distributions to noncontrolling interests	-	-	-	-	-	-	(16)	(16)
Benefit, dividend reinvestment and stock purchase plans	-	-	-	-	-	-	-	-
Stock granted, share-based compensation, net of forfeitures	-	-	(11)	-	-	-	-	(11)
Stock issued, dividend reinvestment plan	0.3	1	9	-	-	-	-	10
Stock issued, share-based compensation, net of forfeitures	0.5	3	20	-	-	(3)	-	20
Purchase of treasury shares	-	-	-	-	-	(2)	-	(2)
Issuance of shares for Nicor merger	38.2	191	1,332	-	-	-	-	1,523
Stock-based compensation expense, net of tax	-	-	8	-	-	-	-	8
As of December 31, 2011	117.0	$586	$1,989	$967	$(217)	$(7)	$21	$3,339
Net income	-	-	-	271	-	-	15	286
Other comprehensive loss	-	-	-	-	(1)	-	-	(1)
Dividends on common stock ($1.74 per share)	-	-	-	(203)	-	-	-	(203)
Distributions to noncontrolling interests	-	-	-	-	-	-	(14)	(14)
Stock granted, share-based compensation, net of forfeitures	-	-	(10)	-	-	-	-	(10)
Stock issued, dividend reinvestment plan	0.3	1	9	-	-	-	-	10
Stock issued, share-based compensation, net of forfeitures	0.6	3	19	-	-	(1)	-	21
Stock-based compensation expense, net of tax	-	-	7	-	-	-	-	7
As of December 31, 2012	117.9	$590	$2,014	$1,035	$(218)	$(8)	$22	$3,435

See Notes to Consolidated Financial Statements.

AGL RESOURCES INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

In millions	Years ended December 31, 2012	2011	2010
Cash flows from operating activities			
Net income	$286	$186	$250
Adjustments to reconcile net income to net cash flow provided by operating activities			
Depreciation and amortization	415	186	160
Deferred income taxes	154	214	92
Change in derivative instrument assets and liabilities	72	(17)	7
Changes in certain assets and liabilities			
Trade payables, other than energy marketing	51	(68)	(14)
Inventories	42	158	33
Prepaid taxes	37	(88)	14
Accrued natural gas costs	37	(3)	(14)
Receivables, other than energy marketing	19	45	(26)
Energy marketing receivables and trade payables, net	(49)	27	47
Accrued expenses	(22)	(77)	7
Other, net	(39)	(112)	(30)
Net cash flow provided by operating activities	1,003	451	526
Cash flows from investing activities			
Acquisition of Nicor Inc, net of cash acquired	0	(912)	0
Expenditures for property, plant and equipment	(782)	(427)	(510)
Proceeds from the disposition of assets	0	0	73
Other, net	(4)	0	(5)
Net cash flow used in investing activities	(786)	(1,339)	(442)
Cash flows from financing activities			
Dividends paid on common shares	(203)	(148)	(136)
Payment of long-term debt	(15)	(300)	0
Distribution to noncontrolling interest	(14)	(16)	(27)
Issuances of long-term debt	0	1,289	0
Net payments and borrowings of short-term debt	56	91	131
Benefit, dividend reinvestment and stock purchase plan	21	19	8
Proceeds from term loan facility	0	150	0
Payments of term loan facility	0	(150)	0
Issuances of gas facility revenue bonds	0	0	160
Payments of gas facility revenue bonds	0	0	(160)
Purchase 15% ownership in SouthStar from Piedmont	0	0	(58)
Other, net	0	(2)	(4)
Net cash flow (used in) provided by financing activities	(155)	933	(86)
Net increase (decrease) in cash and cash equivalents	62	45	(2)
Cash and cash equivalents at beginning of period	69	24	26
Cash and cash equivalents at end of period	$131	$69	$24
Cash paid (received) during the period for			
Interest	$174	$116	$107
Income taxes	$(37)	$12	$58
Non cash transactions			
Merger with Nicor, common stock issued 38.2 million shares	$0	$1,523	$0

See Notes to Consolidated Financial Statements.

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 of 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.

Basis of Presentation

Our consolidated financial statements as of and for the period ended December 31, 2012 are prepared in accordance with GAAP and under the rules of the SEC. Our consolidated financial statements include our accounts, the accounts of our wholly owned subsidiaries, the accounts of our majority-owned and controlled subsidiaries and the accounts of our variable interest entity for which we are the primary beneficiary. For unconsolidated entities that we do not control, but exercise significant influence over, we use the equity method of accounting and our proportionate share of income or loss is recorded on the Consolidated Statements of Income. See Note 10 for additional information. We have eliminated intercompany profits and transactions in consolidation except for intercompany profits where recovery of such amounts are probable 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.

On December 9, 2011, we closed our merger with Nicor and created a combined company with increased scale and scope in the distribution, storage and transportation of natural gas. The businesses acquired in the merger are included for all of 2012, and for only 22 days of 2011 in our consolidated financial statements. See Note 3 for additional information.

Note 2 - Significant Accounting Policies and Methods of Application

Cash and Cash Equivalents

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

Receivables and Allowance for Uncollectible Accounts

Our receivables primarily consist of natural gas sales and transportation services billed to residential, commercial, industrial and other customers. We bill customers monthly, and our 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. For 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 change as well. 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. Customers' accounts are written off once we deem them to be uncollectible.

Nicor Gas Credit risk exposure at Nicor Gas is mitigated by the bad debt rider approved by the Illinois Commission on February 2, 2010. The bad debt rider provides for the recovery from (or refund to) customers of the difference between Nicor Gas' actual bad debt experience on an annual basis and the benchmark bad debt expense used to establish its base rates for the respective year. For more information on the bad debt rider, see discussion in Regulatory Assets and Liabilities.

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. The functions of the retail sale of gas 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

Except for Nicor Gas, distribution operations records natural gas stored underground at WACOG. Nicor Gas' inventory is carried at cost on a LIFO basis. For our retail operations, wholesale services and midstream operations businesses, we account for natural gas inventory at the lower of WACOG or market price.

Based on the average cost of gas purchased in December 2012, the estimated replacement cost of Nicor Gas' inventory at December 31, 2012 exceeded the LIFO cost by $190 million. At December 31, 2012, the Nicor Gas LIFO inventory balance was $119 million.

Our retail operations, wholesale services, and midstream operations segments evaluate the weighted 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, we record adjustments to reduce the weighted average cost of the natural gas inventory to market price. Consequently, as a result of declining natural gas prices, retail operations, wholesale services and midstream operations recorded LOCOM adjustments to cost of goods sold in the following amounts, to reduce the value of their inventories to market value.

In millions	**2012**	**2011**	**2010**
Retail operations	$3	$5	$0
Wholesale services	19	31	8
Midstream operations	1	0	0

In Georgia's competitive environment, Marketers including SouthStar, sell natural gas to firm end-use customers at market-based prices. Part of the unbundling process, which resulted from deregulation and provides 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.

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 our wholesale services segment 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. While the amounts due from or owed to wholesale services' counterparties are settled net, they are recorded on a gross basis in 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, 2012 and 2011, 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.

Wholesale services 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. We evaluate the credit risk of our 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, we assign an internal rating based on our analysis of the strength of its financial ratios. The following table provides additional information about wholesale services' credit exposure at December 31, 2012, excluding $10 million of customer deposits.

Dollars in millions	**Total** (1)	**# of top counterparties**	**Concentration risk %**
Credit exposure	$211	20	50%

(1) Our counterparties or the counterparties' guarantors had a weighted average S&P equivalent rating of A- at December 31, 2012.

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.

We have 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 wholesale services 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 our credit risk. Wholesale services also uses other netting agreements with certain counterparties with whom it conducts significant transactions.

Fair Value Measurements

We have financial and nonfinancial assets and liabilities subject to fair value measures. The financial assets and liabilities measured and carried at fair value include cash equivalents, receivables, derivative assets and liabilities. The carrying values of cash and cash equivalents, short and long-term investments, derivative assets and liabilities, accounts payable, short-term debt, other current assets and liabilities and accrued interest approximate fair value. The nonfinancial assets and liabilities include pension and other retirement benefits. See Note 4 for additional fair value disclosures.

As defined in the 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 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:

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 exchange-traded derivatives, money market funds and retirement plan assets.

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 marketplace. 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 and retirement plan assets.

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. Transfers into and out of Level 3 reflect the liquidity at the relevant natural gas trading locations and dates, which affects the significance of unobservable inputs used in the valuation applied to natural gas derivatives. Our Level 3 assets, liabilities and any applicable transfers are primarily related to our pension and other retirement benefit plan assets as described in Note 3, Note 4 and Note 6. Transfers for retirement plan assets are described further in Note 4. We determine both transfers into and out of Level 3 using values at the end of the interim period in which the transfer occurred.

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

Derivative Instruments

Our policy is to classify derivative cash flows in the same category as the hedged item, rather than by the nature of the instrument.

Fair Value Hierarchy As required by the authoritative guidance, derivative 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 own nonperformance risk on our liabilities. To mitigate the risk that a counterparty to a derivative instrument defaults on settlement or otherwise fails to perform under contractual terms, we have established procedures to monitor the creditworthiness of counterparties, seek guarantees or collateral back-up in the form of cash or letters of credit and, in most instances, enter into netting arrangements. See Note 4 for additional fair value disclosures.

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.

We have elected to net derivative assets and liabilities under master netting arrangements on our Consolidated Statements of Financial Position. With that election, we are also required to offset cash collateral held in our broker accounts with the associated net fair value of the instruments in the accounts. See Note 4 for additional information about our cash collateral.

Natural Gas Derivative Instruments

The fair value of the natural gas derivative instruments that 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 instruments. See Note 5 for additional derivative disclosures.

Distribution Operations Nicor Gas, subject to review by the Illinois Commission, and Elizabethtown Gas, in accordance with a directive from the New Jersey BPU, enter into derivative instruments to hedge the impact of market fluctuations in natural gas prices. As previously noted, such derivative instruments are carried at fair value each reporting period in our Consolidated Statements of Financial Position. In accordance with regulatory requirements, any realized gains and losses related to these derivatives are reflected in natural gas costs and ultimately included in billings to customers. Thus, hedge accounting is not elected and, in accordance with accounting guidance pertaining to rate-regulated entities, unrealized changes in the fair value of these derivative instruments are deferred or accrued as regulatory assets or liabilities until the related revenue is recognized.

Nicor Gas also enters into derivative instruments to reduce the earnings volatility of certain forecasted operating costs arising from fluctuations in natural gas prices, such as the purchase of natural gas for company use. These derivative instruments are carried at fair value. To the extent hedge accounting is not elected, changes in such fair values are recorded in the current period as operating and maintenance expense.

Retail Operations We have designated a portion of our derivative 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 that the underlying hedged item is recognized in earnings.

We currently have minimal hedge ineffectiveness defined as when the gains or losses on the hedging instrument do not completely offset the losses or gains on the hedged item. This cash flow hedge ineffectiveness is recorded in cost of goods sold in our Consolidated Statements of Income in the period in which it occurs. We have not designated the remainder of our derivative instruments as hedges for accounting purposes and, accordingly, we record changes in the fair value of such instruments within cost of goods sold in our Consolidated Statements of Income in the period of change.

We enter into weather derivative contracts as economic hedges of operating margins in the event of warmer-than-normal weather in the Heating Season. We account for these contracts using the intrinsic value method. These weather derivative instruments do not qualify for hedge accounting designation and changes in the intrinsic value of the contracts are reflected in cost of goods sold on our Consolidated Statements of Income.

Wholesale Services We purchase natural gas for storage when the current market price we pay to buy and transport natural gas plus the cost to store and finance 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 and OTC contracts 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. We also enter into transactions to secure transportation capacity between two delivery points in order to serve our customers and various markets. We use NYMEX futures and OTC contracts to capture the price differential or spread between the locations served by the capacity in order to substantially lock in the operating margin we will ultimately realize when we physically flow natural gas between the two delivery points. These contracts generally meet the definition of derivatives and are carried 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. These contracts are not designated as hedges for accounting purposes.

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 and transportation portfolio. Further, we incur monthly demand charges for the contracted storage and transportation capacity, and payments associated with asset management agreements and recognize these demand charges and payments in our Consolidated Statements of Income in the period they are incurred. 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.

Debt

We estimate the fair value of 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 consider our currently assigned ratings for unsecured debt and the secured rating for the Nicor Gas first mortgage bonds.

Property, Plant and Equipment

A summary of our PP&E by classification as of December 31, 2012 and 2011 is provided in the following table.

In millions	**2012**	**2011**
Transportation and distribution	$7,992	$7,579
Storage caverns	1,149	931
Shipping vessels and containers	145	146
Other	820	747
Construction work in progress	372	376
Total gross PP&E	10,478	9,779
Less accumulated depreciation	2,131	1,879
Total net PP&E	$8,347	$7,900

Distribution Operations PP&E consists of property and equipment that is currently in use, being held for future use and currently 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
- Nicor Gas' pad gas - the portion considered to be non-recoverable is recorded as depreciable PP&E while the portion considered to be recoverable is recorded as non-depreciable PP&E

We recognize no gains or losses on depreciable utility property that is retired or otherwise disposed, as required under the composite depreciation method. Such gains and losses are ultimately refunded to or recovered from customers through future rate adjustments. Our gas distribution utilities also hold property, primarily land; this is not presently used and useful in utility operations and is not in rate base. Upon sale, any gain or loss is recognized in other income.

Retail Operations, Wholesale Services, Midstream Operations, Cargo Shipping and Other PP&E includes 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 salt-dome storage at Jefferson Island and Golden Triangle Storage that is retained as pad gas is classified as non-depreciable PP&E and is carried at cost. Central Valley has two types of pad gas in its depleted reservoir storage facility. The first is non-depreciable PP&E, which is carried at cost, and the second is non-recoverable to which we have no contractual ownership.

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. More information on our rates used and the rate method is provided in the following table.

	2012	2011	2010
Atlanta Gas Light (1)	2.6%	2.6%	2.5%
Chattanooga Gas (1)	2.5%	2.5%	2.8%
Elizabethtown Gas (2)	2.4%	2.5%	2.4%
Elkton Gas (2)	2.4%	2.4%	2.3%
Florida City Gas (2)	3.9%	3.9%	3.7%
Nicor Gas (2)	4.1%	4.1%	n/a
Virginia Natural Gas (1)	2.5%	2.5%	3.0%

(1) Average composite straight-line depreciation rates for depreciable property, excluding transportation equipment, which may be depreciated in excess of useful life and recovered in rates.
(2) Composite straight-line depreciation rates.

For our non-regulated segments we compute depreciation expense on a straight-line basis over the following estimated useful lives of the assets as seen in the following table.

In years	Estimated useful life
Transportation equipment	5 - 10
Shipping vessels	20 - 25
Storage caverns	40 - 60
Other	up to 40

AFUDC and Capitalized Interest

Four of our utilities are authorized by applicable state regulatory agencies or legislatures to capitalize the cost of debt and equity funds as part of the cost of construction projects in our Consolidated Statements of Financial Position. Nicor Gas does not have authorized AFUDC rates, but rather it is authorized to capitalize AFUDC at the current actual cost of debt and equity, if applicable. The capital expenditures of our two other utilities do not qualify for AFUDC treatment. More information on our authorized or actual AFUDC rates is provided in the following table.

	2012	2011	2010
Atlanta Gas Light	8.10%	8.10%	8.10%
Chattanooga Gas	7.41%	7.41%	7.41%
Elizabethtown Gas (1)	0.51%	0.53%	0.40%
AFUDC (in millions) (2)	$9	$6	$3

(1) Variable rate is determined by FERC method of AFUDC accounting.
(2) Amounts recorded in the Consolidated Statements of Income.

Impairment of Goodwill and Long-Lived Assets, including Intangible Assets

Our goodwill is not amortized, but is subject to an annual impairment test. Our other long-lived assets, including our finite-lived intangible assets require an impairment review when events or circumstances indicate that the carrying amount may not be recoverable. We base our evaluation of other long-lived assets on the presence of impairment indicators such as the future economic benefit of the assets, any historical or future profitability measurements and other external market conditions or factors.

Goodwill

We perform an annual goodwill impairment test on our reporting units that contain goodwill during the fourth quarter of each year, 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. To estimate the fair value of our reporting units, we used two generally accepted valuation approaches, an income approach and a market approach, using assumptions consistent with a market participant's perspective.

Under the income approach, fair value is determined based upon the present value of estimated future cash flows discounted at an appropriate risk-adjusted rate. These forecasts contain a degree of uncertainty, and changes in these projected cash flows could significantly increase or decrease the fair value of a reporting unit. For the regulated reporting units, a fair recovery of and return on costs prudently incurred to serve customers is assumed. An unfavorable outcome in a rate case could cause the fair value of these reporting units to decrease. Key assumptions used in the income approach included return on equity for the regulated reporting units, long-term growth rates used to determine terminal values at the end of the discrete forecast period, and discount rates. The discount rate is applied to estimated future cash flows and is one of the most significant assumptions used to determine fair value under the income approach. As interest rates rise, the calculated fair values will decrease. The terminal growth rate was based on a combination of historical and forecasted statistics for real gross domestic product and personal income for each utility service area.

Under the market approach, fair value is determined by applying multiples to forecasted cash flows. This method uses metrics from similar publicly traded companies in the same industry to determine how much a knowledgeable investor in the marketplace would be willing to pay for an investment in a similar company.

The goodwill impairment testing develops a baseline test and performs a sensitivity analysis to calculate a reasonable valuation range. The sensitivities are derived by altering those assumptions which are subjective in nature and inherent to a discounted cash flows calculation. We weight the results of the two valuation approaches to estimate the fair value of each reporting unit.

Our goodwill impairment analysis for the year ended December 31, 2012, indicated that the estimated fair value of all but one of our reporting units with goodwill was in excess of the carrying value by approximately 20% to over 500%, and are not at risk of failing step one of the impairment test. The estimated fair value of a reporting unit within our midstream operations segment, with $14 million of goodwill, exceeded its carrying value by less than 10%. The significant assumptions that drive the estimated fair value are projected cash flows, current and future rates for contracted capacity, growth rates, weighted average cost of capital and market multiples. Due to the subjectivity of these assumptions, we cannot provide assurance that future analyses will not result in impairment as a future impairment depends on market and economic factors affecting fair value.

Long-Lived Assets

We depreciate/amortize our long-lived assets, including intangible assets, over their useful lives. Currently, we have no significant indefinite-lived intangible assets. These assets are reviewed for impairment when events or changes in circumstances indicate that the carrying amount of the asset may not be recoverable. When such events or circumstances are present, we assess the recoverability of long-lived assets by determining whether the carrying value will be recovered through expected future cash flows. An impairment is indicated if the carrying amount of the long-lived asset exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If an impairment is indicated, we record an impairment loss equal to the difference between the carrying value and the fair value of the long-lived asset. We determined that there were no long-lived asset impairments in 2012 or 2011.

Intangible Assets

Our intangible assets increased substantially as a result of the merger with Nicor in 2011 and relate primarily to trade names and customer relationships with definite useful lives ranging up to 18 years. Intangible assets, net of accumulated amortization were $96 million at December 31, 2012 and $105 million at December 31, 2011. Amortization expense was $9 million in 2012 and $0 in 2011 and 2010. Amortization for the next five years is estimated to be:

In millions	**Amortization Expense**
2013	$9
2014	9
2015	9
2016	9
2017	8

Taxes

Income Taxes The reporting of our assets and liabilities for financial accounting purposes differs from the reporting for income tax purposes. The principal differences between net income and taxable income relate to the timing of deductions, primarily due to the benefits of tax depreciation since we generally depreciate assets for tax purposes over a shorter period of time than for book purposes. The determination of our provision for income taxes requires significant judgment, the use of estimates, and the interpretation and application of complex tax laws. Significant judgment is required in assessing the timing and amounts of deductible and taxable items. We report the tax effects of depreciation and other differences in those items as deferred income tax assets or liabilities in our Consolidated Statements of Financial Position.

We have current and deferred income taxes in our Consolidated Statements of Income. 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 tax expense.

Accumulated Deferred Income Tax Assets and Liabilities As noted above, 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 these deferred income tax assets and liabilities using enacted income tax rates.

A deferred income tax liability is not recorded on undistributed foreign earnings that are expected to be indefinitely reinvested offshore. We consider, among other factors, actual cash investments offshore as well as projected cash requirements in making this determination. Changes in our investment or repatriation plans or circumstances could result in a different deferred income tax liability. We had $80 million of such cash and investments on our Consolidated Statements of Financial Position as of December 31, 2012 and $71 million as of December 31, 2011. These amounts were generated from our Cargo Shipping segment.

Regulatory Income Tax Liability For our regulated utilities we also measure deferred income tax assets and liabilities using enacted income tax rates. Thus, when the statutory income tax rate declines before a temporary difference has fully reversed, the deferred income tax liability must be reduced to reflect the newly enacted income tax rates. However, the amount of the reduction is transferred to our regulatory income tax liability, which we are amortizing over the lives of the related properties as the temporary difference reverses over approximately 30 years.

Income 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 upon 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 addresses derecognition, classification, interest and penalties on income taxes, and accounting in interim periods.

Uncertain Tax Positions We recognize accrued interest related to uncertain tax positions in interest expense and penalties in operating expense in our Consolidated Statements of Income. As of December 31, 2012, we did not have a liability recorded for payment of interest or penalties associated with uncertain tax positions.

Tax Collections We do not collect income taxes from our customers on behalf of governmental authorities. However, we do collect and remit various taxes on behalf of various governmental authorities. We record these amounts in our Consolidated Statements of Financial Position. In other instances, we are allowed to recover from customers other taxes that are imposed upon us. We record such taxes as operating expense and record the corresponding customer charges as revenue.

Revenues

Distribution operations We record revenues when goods or 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, Atlanta Gas Light bills Marketers in equal monthly installments for each residential, commercial and industrial customer's distribution costs. Additionally, as required by the Georgia Commission, Atlanta Gas Light utilizes 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 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 recognizes its residential SFV capacity revenues in equal monthly installments.

All of our utilities, with the exception of Atlanta Gas Light, have rate structures that include volumetric rate designs which 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 bill 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 Virginia Natural Gas, Elizabethtown Gas and Chattanooga Gas contain WNAs that partially mitigate the impact of unusually cold or warm weather on customer billings and operating margin. The purpose of a WNA 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 tariffs for Chattanooga Gas and Elkton Gas contain revenue normalization mechanisms that mitigate the impact of conservation and declining customer usage.

Revenue Taxes We charge customers for revenue taxes imposed on us and remit amounts owed to various governmental authorities. Our policy is to record all such taxes charged to customers as operating revenues and the related taxes incurred as operating expenses in our Consolidated Statements of Income. Revenue taxes included in operating expenses were $85 million for the year ended December 31, 2012, $9 million in 2011 and no revenue taxes in 2010.

Retail operations 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.

We recognize revenue on 12-month utility-bill management contracts as the lesser of cumulative earned or cumulative billed amounts. We recognize revenue for warranty and repair contracts on a straight-line basis over the contract term. Revenue for maintenance services is recognized at the time such services are performed.

Wholesale services We record wholesale services' revenues when services are provided to customers. Profits from sales between segments are eliminated in the other 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. Gains and losses on derivatives held for energy trading purposes are required to be presented net in revenue.

Midstream operations We record operating revenues for storage and transportation services 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.

Cargo shipping Revenues are recognized at the time vessels depart from port. Insurance premiums are recognized when the vessel carrying the insured cargo reaches its port of destination and the insured cargo is released to the consignee. The portion of premiums not earned at the end of the year is recorded as unearned premiums.

Cost of goods sold

Distribution operations 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, all prudently incurred natural gas costs are passed through to customers without markup, subject to regulatory review. In accordance with the authoritative guidance for rate-regulated entities, we defer or accrue (that is, include as an asset or liability in the Consolidated Statements of Financial Position and exclude from or include in the Consolidated Statements of Income, respectively) the difference between the actual cost of goods sold incurred and the amount of commodity revenue earned in a given period, such that no operating margin is recognized related to these costs. The deferred or accrued amount is either billed or refunded to our customers prospectively through adjustments to the commodity rate. Deferred natural gas costs are reflected as regulatory assets identified as recoverable natural gas costs, and accrued natural gas costs are reflected as regulatory liabilities, which are identified as accrued natural gas costs within our Consolidated Statements of Financial Position. For more information, see "Regulatory Assets and Liabilities" in Note 2.

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

Repair and maintenance expense

We record expense for repair and maintenance costs as incurred. This includes expenses for planned major maintenance, such as dry-docking the vessels owned by our cargo shipping business.

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. This accounting treatment does not affect the future annual operating lease cash obligations. For more information, see "Commitments, Guarantees and Contingencies" in Note 11.

Other income (expense)

Our other income (expense), net is detailed in the following table. For more information on our equity investment income, see Note 10.

In millions	**2012**	**2011**	**2010**
Equity investment income	$13	$1	$0
AFUDC - equity	6	4	2
Other, net	5	2	(3)
Total other income (expense)	$24	$7	$(1)

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. The increase in weighted average shares in 2012 compared to 2011 is primarily due to the issuance of 38.2 million shares in connection with the Nicor merger on December 9, 2011.

We derive our potentially dilutive common shares by calculating the number of shares issuable under restricted stock, restricted stock units and stock options. The vesting of certain shares of the restricted stock and restricted stock units depends on the satisfaction of defined 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 (except per share amounts)	**2012**	**2011**	**2010**
Net income attributable to AGL Resources Inc.	$271	$172	$234
Denominator:			
Basic weighted average number of shares outstanding (1)	117.0	80.4	77.4
Effect of dilutive securities	0.5	0.5	0.4
Diluted weighted average number of shares outstanding	117.5	80.9	77.8
Basic and diluted earnings per share			
Basic	$2.32	$2.14	$3.02
Diluted	$2.31	$2.12	$3.00

(1) Daily weighted average shares outstanding.

The following table contains the weighted average number of 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	**2012**	**2011**	**2010**
Twelve months ended	0.0	0.0	0.8

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 in the current period are capitalized as regulatory assets when it is probable that such costs or 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 associated assets and liabilities as of December 31, are summarized in the following table.

In millions	**2012**	**2011**
Regulatory assets		
Recoverable regulatory infrastructure program costs	$47	$48
Recoverable ERC	38	7
Recoverable pension and other retirement benefit costs	19	29
Other regulatory assets	41	47
Total regulatory assets - current	145	131
Recoverable ERC	438	351
Recoverable pension and other retirement benefit costs	196	262
Recoverable regulatory infrastructure program costs	167	305
Long-term debt fair value adjustment	90	99
Other regulatory assets	53	62
Total regulatory assets - long-term	944	1,079
Total regulatory assets	$1,089	$1,210
Regulatory liabilities		
Accrued natural gas costs	$93	$53
Bad debt rider	37	30
Accumulated removal costs	16	14
Other regulatory liabilities	15	15
Total regulatory liabilities - current	161	112
Accumulated removal costs	1,393	1,321
Unamortized investment tax credit	29	32
Regulatory income tax liability	27	27
Bad debt rider	17	14
Other regulatory liabilities	11	11
Total regulatory liabilities - long-term	1,477	1,405
Total regulatory liabilities	$1,638	$1,517

Our regulatory assets are probable of recovery as authorized by a state regulatory commission. Base rates are designed to provide both a recovery of cost and a return on investment during the period rates are in effect. As such, all of our regulatory assets recoverable through base rates are subject to review by the respective state regulatory commission during 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 we believe that we will be able to recover such costs, consistent 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, while some regulatory liabilities would be written-off, others would continue to be recorded as liabilities but not as regulatory liabilities.

Although the natural gas distribution industry is competing with alternative fuels, primarily electricity, 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 that do not represent revenue collected from customers for expenditures that have not yet been incurred 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.

The majority of our regulatory assets and liabilities listed in the preceding table are included in base rates except for the recoverable regulatory infrastructure program costs, recoverable ERC, the bad debt rider and accrued natural gas costs, which are recovered through specific rate riders on a dollar-for-dollar basis. The rate riders that authorize the recovery of regulatory infrastructure program costs and natural gas costs include both a recovery of cost and a return on investment during the recovery period. Nicor Gas' rate riders for environmental costs and energy efficiency costs provide a return of investment and expense including short-term interest on reconciliation balances. However, there is no interest associated with the under or over collections of bad debt expense.

Nicor Gas' pension and other retirement benefit costs have historically been considered in rate proceedings in the period they are accrued. As a regulated utility, Nicor Gas expects to continue rate recovery of the eligible costs of these defined benefit retirement plans and, accordingly, associated changes in the funded status of Nicor Gas' plans have been deferred as a regulatory asset or liability until recognized in net income, instead of being recorded in accumulated OCI. However, to the extent Nicor Gas' employees perform services for affiliates, and to the extent such employees are eligible to participate in these plans, the affiliates are charged for the cost of these benefits and changes in the funded status that are expected to be recovered from affiliates in the future are recorded in accumulated OCI. The Illinois Commission presently does not allow Nicor Gas the opportunity to earn a return on its recoverable retirement benefit costs. Such costs are expected to be recovered over a period 11 years. The regulatory assets related to debt are also not included in rate base, but the costs are recovered over the term of the debt through the authorized rate of return component of base rates.

Environmental Remediation Costs Our ERC liabilities are estimates of future remediation costs for investigation and clean up of our former operating sites that are contaminated. Our estimates are based on conventional engineering estimates and the use of probabilistic models of potential costs when such estimates cannot be made, 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 them. 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 paid and accrued ERCs are deferred in a corresponding regulatory asset until the costs are recovered from customers. We primarily recover these deferred costs through three rate riders that authorize dollar-for-dollar recovery. The ERC rate rider for Atlanta Gas Light allows for recovery of the costs incurred over the subsequent five-year period. The ERC associated with the investigation and remediation of Nicor Gas and Elizabethtown Gas remediation sites located in the states of Illinois and New Jersey are recovered under remediation adjustment clauses that include carrying cost on unrecovered expenditures. For more information on our ERC liabilities, see Note 11.

Bad Debt Rider Nicor Gas' bad debt rider provides for the recovery from, or refund to, customers of the difference between Nicor Gas' actual bad debt experience on an annual basis and a benchmark bad debt expense of $63 million, as determined by the Illinois Commission in February 2010. Nicor Gas' actual 2012 bad debt experience was $23 million, resulting in a refund to customers of $40 million which will be refunded between June 2013 and May 2014. Nicor Gas' actual 2011 bad debt experience was $31 million, resulting in a refund to customers of $32 million of which $19 million was refunded in 2012 and $13 million will be refunded by May 2013. The over recovery is recorded as a decrease to operating expenses on our Consolidated Statements of Income in the period refunded to customers and is recorded as a regulatory liability on our Consolidated Statements of Financial Position until then.

Accumulated Removal Costs In accordance with regulatory treatment, our depreciation rates are comprised of two cost components - historical cost and the estimated cost of removal, net of estimated salvage, of certain regulated properties. We collect these costs in base rates through straight-line depreciation expense, with a corresponding credit to accumulated depreciation. Because the accumulated estimated removal costs are a generally accepted component of depreciation, but meet the requirements of authoritative guidance related to regulated operations, we have accounted for them as a regulatory liability and have reclassified them from accumulated depreciation to accumulated removal costs in our Consolidated Statements of Financial Position. In the rate setting process, the liability for these accumulated removal costs are treated as a reduction to the net rate base upon which our regulated utilities have the opportunity to earn their allowed rate of return. Our accumulated removal costs increased $74 million in 2012 due to accretion.

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 December 31, 2012, we have completed the replacement of all our cast iron pipes, and the remaining replacements are on schedule.

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 revenues recognized to date that have not yet been recovered from customers through the rate riders, and (ii) the future expected costs to be recovered through the rate riders.

Atlanta Gas Light has recorded a current regulatory asset of $47 million, which represents the amount of recognized revenues expected to be collected from customers over the next 12 months. Atlanta Gas Light has also recorded a non-current asset of $167 million, which represents the expected future collection of revenues already recognized. The amounts recovered from the pipeline replacement revenue rider during the last three years were:

- $51 million in 2012
- $48 million in 2011
- $45 million in 2010

As of December 31, 2012, Atlanta Gas Light had recorded a current liability of $121 million representing expected program expenditures for the next 12 months and no long-term liability.

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). The purpose of the i-SRP 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. 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 i-CGP, the Georgia Commission authorized Atlanta Gas Light to extend its 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 all related costs will be recovered through a surcharge.

In 2009, the New Jersey BPU approved an enhanced infrastructure program for Elizabethtown Gas, which was created in response to the New Jersey Governor's request for utilities to assist in the economic recovery by increasing infrastructure investments. In May 2011, the New Jersey BPU approved Elizabethtown Gas' request to spend an additional $40 million under this program before the end of 2012. Costs associated with the investment in this program are recovered through periodic adjustments to base rates. In July 2012, we filed for an extension of the program up to $135 million in additional spend over five years and we expect a ruling in the first half of 2013.

On June 25, 2012, the Virginia Commission approved SAVE, an accelerated infrastructure replacement program, which is expected to be completed over a five-year period. The program permits a maximum capital expenditure of $25 million per year, not to exceed $105 million in total. SAVE is subject to annual review by the Virginia Commission. We began recovering costs based on this program through a rate rider that was effective August 1, 2012.

Other Regulatory Assets and Liabilities Our recoverable pension and other retirement benefit plan costs are recoverable through base rates over the next 2 to 21 years, based on the remaining recovery period as designated by the applicable state regulatory commissions. This category also includes recoverable seasonal rates, which 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.

Accounting for Retirement Benefit Plans

The authoritative guidance related to retirement benefits requires that we recognize the obligations related to each defined benefit retirement plan and quantify the plans' funded 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 yet recognized as part of net periodic benefit cost as explained in authoritative guidance related to retirement benefits. Because substantially all of its retirement costs are recoverable through base rates, Nicor Gas generally defers any charge or credit to a regulatory asset or liability until the period in which the costs are included in base rates, in accordance with the authoritative guidance for rate-regulated entities. The assets of our retirement plans are accounted for at fair value and are classified in the fair value hierarchy 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 business 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. For entities that are not determined to be VIEs, we evaluate whether we have control or significant influence over the joint venture to determine the appropriate consolidation and presentation. Generally, entities under our control are consolidated, and entities over which we can exert significant influence, but do not control, are accounted for under the equity method of accounting.

We have concluded that the only venture that we are required to consolidate as a VIE, as 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 consolidation of SouthStar 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.

We also invest in partnerships and limited liability companies that are accounted for under the equity method, but are not joint ventures. All such investments are required to use the equity method unless our interest is so minor that there is virtually no influence over operating and financial policies.

Investments accounted for under the equity method are included in long-term investments on our Consolidated Statements of Financial Position, and the equity income is recorded within other income on our Consolidated Statements of Income and was immaterial for all periods presented. For additional information, see Note 10.

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. Our estimates are based 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 relate to our pipeline replacement program accruals, environmental liability accruals, uncollectible accounts and other allowances for contingent losses, goodwill and intangible assets, retirement plan benefit obligations, derivative and hedging activities and provisions for income taxes. We evaluate our estimates on an ongoing basis and our actual results could differ from our estimates.

Accounting Developments

On January 1, 2012, we adopted authoritative guidance related to fair value measurements. The guidance expands the qualitative and quantitative disclosures required for Level 3 significant unobservable inputs. The guidance also limits the application of the highest and best use premise to non-financial assets and liabilities. This guidance had no impact on our consolidated financial statements. See Note 4 for additional fair value disclosures.

On January 1, 2012, we adopted authoritative guidance related to comprehensive income. The guidance eliminates the option to present OCI in the statement of equity, but allows companies to elect to present net income and OCI in one continuous statement of comprehensive income, or in two consecutive statements. This guidance does not change any of the components of net income or OCI, and earnings per share continues to be calculated based on net income. This guidance did not have a material impact on our consolidated financial statements.

Note 3 - Merger with Nicor

On December 9, 2011, we completed our merger with Nicor. In accordance with the Merger Agreement, each share of Nicor common stock outstanding at the Effective Date, other than shares cancelled and Dissenting Shares, as defined in the Merger Agreement, was converted into purchase consideration of (i) 0.8382 of a share of AGL Resources common stock and (ii) $21.20 in cash. Fractional shares were not issued in connection with the merger as Nicor shareholders who would have been entitled to receive a fraction of a share of AGL Resources common stock received cash settlements. Additionally, cash was paid to repurchase stock options and restricted stock units that were awarded for pre-merger services. Nicor's previous shareholders own approximately 33% of the combined company. The value of the consideration paid to Nicor shareholders was calculated as follows:

In millions, except per share price	
Nicor shares outstanding at the Effective Date	45.5
Exchange ratio	0.8382
Number of shares of AGL Resources common stock issued	38.2
Volume-weighted average price of AGL Resources common stock on December 8, 2011	$39.90
Cost of equity issued	$1,523
Nicor shares outstanding at the Effective Date	45.5
Cash payment per share of Nicor common stock	$21.20
Cash paid for Nicor common shares outstanding	$966
Cash paid to repurchase outstanding equity awards	$14
Cost of debt issued	$980
Total purchase consideration	$2,503

The allocation of the total consideration transferred in the merger to the fair value of assets acquired and liabilities assumed includes adjustments for the fair value of Nicor's assets and liabilities. This allocation is presented in the following table.

In millions	
Current assets	$955
Property, plant and equipment	3,192
Goodwill	1,423
Other noncurrent assets, excluding goodwill	891
Current liabilities	(1,194)
Long-term debt	(599)
Other noncurrent liabilities	(2,165)
Total purchase consideration	$2,503

The allocation of purchase price in the table above reflects refinements made during the measurement period primarily related to increased ERC liabilities for our sites in Illinois, increased valuation allowance on deferred tax assets related to our investment in Triton, increased fair value of certain non-utility assets, reduced fair value of certain property, plant and equipment and reclassifying a portion of the ERC liability from long-term to current. The impact of the refinements on the depreciation and amortization of purchase accounting adjustments was not material.

The estimated fair values of the assets acquired and the liabilities assumed were determined based on the accounting guidance for fair value measurements under GAAP, which defines fair value as 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. The estimated fair value measurements assume the highest and best use of the assets by market participants, considering the use of the asset that is physically possible, legally permissible and financially feasible at the measurement date.

We concluded that net book value is a reasonable estimate of fair value for Nicor's tangible and intangible assets and liabilities that are explicitly subject to cost-of-service ratemaking. We determined the fair value of Nicor's long-term debt using the income approach, and used a discounted cash flow technique that incorporates a market interest yield curve with adjustments for duration, optionality and risk profile. As a result, our purchase price allocation included an adjustment of $99 million to step-up the basis of Nicor's long-term debt to fair value as of the merger date. A corresponding regulatory asset was recorded in connection with the fair value adjustment of the debt. While the regulatory asset related to debt is not included in rate base, the costs are recovered over the term of the debt through the authorized rate of return component of base rates. The following table summarizes our purchase price allocation for Nicor Gas' regulatory assets and liabilities:

In millions	
Current assets	$59
Property, plant and equipment	4,881
Other noncurrent assets, excluding goodwill	567
Current liabilities	(107)
Other noncurrent liabilities	(1,138)

For all other assets and liabilities acquired from Nicor, we considered the income, market and cost approaches to determining fair value. The income approach estimates the fair value by discounting the projected future cash flows at our weighted average cost of capital. We utilized this approach to obtain the business enterprise values for each reporting unit. Additionally, we used the income approach to determine the fair values for intangible trade names and customer relationship assets.

The market approach is based on the premise that the fair value can be determined through the use of prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. Finally, the cost approach utilizes the concept of replacement cost as an indicator of fair value. We applied the market and cost approaches to estimate the fair value of the property, plant and equipment. Our valuations included a $35 million step-up for Nicor's non-regulated property, plant and equipment. This was primarily related to the vessels and related equipment in our cargo shipping segment. The excess of the purchase price paid over the estimated fair values of the assets acquired and liabilities assumed was recognized as goodwill, which is not deductible for tax purposes. A rollforward of total goodwill by operating segment in our Consolidated Statements of Financial Position as of December 31, 2012 is as follows:

In millions	**Distribution Operations**	**Retail Operations**	**Wholesale Services**	**Midstream Operations**	**Cargo Shipping**	**Other**	**Consolidated**
Goodwill - December 31, 2010	$404	$0	$0	$14	$0	$0	$418
Merger with Nicor	1,182	124	2	2	77	8	1,395
Goodwill - December 31, 2011	1,586	124	2	16	77	8	1,813
Merger with Nicor and other	54	(2)	(2)	(2)	(16)	(8)	24
Goodwill - December 31, 2012	$1,640	$122	$0	$14	$61	$0	$1,837

The fair value of intangible assets recorded as result of the merger is as follows:

In millions	**Fair Value**	**Weighted average amortization period** (in years)
Trade names:		
Retail operations	$29	15
Cargo shipping	15	15
Customer relationships:		
Retail operations	53	10
Cargo shipping	6	18
Total	$103	

The fair value measurements of intangible assets were primarily based on significant unobservable inputs and thus represent Level 3 measurements as defined in accounting guidance for fair value measurements.

The following table summarizes the estimated fair value of the acquired receivables recorded in connection with the merger:

In millions	
Nicor accounts receivable at December 9, 2011	$400
Cash flows not expected to be collected	24
Fair value of acquired receivables	$376

In connection with the merger, AGL Resources recorded merger transaction costs of $20 million ($13 million net of tax) for the twelve months ended December 31, 2012, $57 million ($48 million net of tax) for the twelve months ended December 31, 2011 and $6 million ($4 million net of tax) for the twelve months ended December 31, 2010. These costs were expensed as incurred and separately stated in our Consolidated Statements of Income. The merger transaction costs recognized for the twelve months ended December 31, 2011 includes $34 million ($31 million net of tax) of change in control and other benefit payments. In addition, our 2011 Consolidated Statements of Income include incremental debt issuance costs related to financing the cash portion of the purchase consideration in advance of the merger closing date. The expense was $25 million ($16 million net of tax) for the twelve months ended December 31, 2011.

The amounts of revenue and earnings of Nicor included in our Consolidated Statements of Income for the periods subsequent to the December 9, 2011 closing date are as follows:

In millions, except per share amounts	**Year Ended December 31, 2012**	**December 10, 2011- December 31, 2011**
Total revenues	$2,063	$209
Net income (1)	$70	$(24)
Basic earnings per common share	$0.60	$(0.30)
Diluted earnings per common share	$0.59	$(0.30)

(1) The period ended December 31, 2011 includes change in control expenses of $31 million (net of taxes).

Pro forma financial information The following unaudited pro forma financial information reflects our consolidated results of operations as if the merger with Nicor had taken place on January 1, 2010. The unaudited pro forma information has been calculated after conforming our accounting policies and adjusting Nicor's results to reflect the depreciation and amortization that would have been charged assuming fair value adjustments to property, plant and equipment, debt and intangible assets had been applied on January 1, 2010, together with the consequential tax effects.

AGL Resources and Nicor together incurred costs directly related to the merger of $96 million in 2011 and $27 million in 2010. These expenses are excluded from the pro forma earnings presented below.

The unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of results of operations that would have been achieved had the pro forma events taken place on the dates indicated, or of the future consolidated results of operations of the combined company.

	Year ended December 31,	
In millions, except per share amounts	**2011**	**2010**
Total revenues	$4,680	$5,083
Net income attributable to AGL Resources Inc.	$304	$343
Basic earnings per common share	$2.62	$2.97
Diluted earnings per common share	$2.61	$2.96

The contingencies acquired as a result of the merger are discussed in Note 11.

Note 4 - Fair Value Measurements

Retirement benefit plans

The target asset allocation of the Nicor Companies Pension and Retirement Plan (Nicor Plan) was approximately 60% equity and 40% fixed income. The target allocations of the AGL Resources Inc. Retirement Plan (AGL Plan), the Employees' Retirement Plan of NUI Corporation (NUI Plan), and the Health and Welfare Plan for Retirees and Inactive Employees of AGL Resources Inc. (AGL Postretirement Plan) were approximately 81% equity and 19% fixed income. The plans' investment policies provide for some variation in these targets. The actual asset allocations of our retirement plans are presented in the following table by Level within the fair value hierarchy.

	December 31, 2012									
	Pension plan (1)					Other retirement plans				
In millions	Level 1	Level 2	Level 3	Total	% of total	Level 1	Level 2	Level 3	Total	% of total
Cash	$14	$2	$0	$16	2%	$1	$0	$0	$1	1%
Equity Securities										
U.S. large cap (2)	69	181	0	250	30%	0	38	0	38	55%
U.S. small cap (2)	60	22	0	82	10%	0	0	0	0	0%
International companies (3)	0	120	0	120	14%	0	12	0	12	18%
Emerging markets (4)	0	34	0	34	4%	0	0	0	0	0%
Fixed income securities										
Corporate bonds (5)	0	216	0	216	26%	0	18	0	18	26%
Other (or gov't/muni bonds)	0	30	0	30	3%	0	0	0	0	0%
Other types of investments										
Global hedged equity (6)	0	0	38	38	4%	0	0	0	0	0%
Absolute return (7)	0	0	36	36	4%	0	0	0	0	0%
Private capital (8)	0	0	23	23	3%	0	0	0	0	0%
Total assets at fair value	$143	$605	$97	$845	100%	$1	$68	$0	$69	100%
% of fair value hierarchy	17%	72%	11%	100%		1%	99%	0%	100%	

	December 31, 2011									
	Pension plan (1)					Other retirement plans				
In millions	Level 1	Level 2	Level 3	Total	% of total	Level 1	Level 2	Level 3	Total	% of total
Cash	$13	$0	$0	$13	2%	$1	$0	$0	$1	2%
Equity Securities										
U.S. large cap (2)	95	134	0	229	30%	0	34	0	34	56%
U.S. small cap (2)	53	25	0	78	10%	0	0	0	0	0%
International companies (3)	0	107	0	107	14%	0	10	0	10	16%
Emerging markets (4)	0	25	0	25	3%	0	0	0	0	0%
Fixed income securities										
Corporate bonds (5)	0	191	0	191	25%	0	0	0	0	0%
Other types of investments										
Other (or gov't/muni bonds)	0	28	0	28	4%	0	16	0	16	26%
Global hedged equity (6)	0	0	30	30	4%	0	0	0	0	0%
Absolute return (7)	0	0	34	34	5%	0	0	0	0	0%
Private capital (8)	0	0	25	25	3%	0	0	0	0	0%
Total assets at fair value	$161	$510	$89	$760	100%	$1	$60	$0	$61	100%
% of fair value hierarchy	21%	67%	12%	100%		2%	98%	0%	100%	

(1) Includes $8 million at December 31, 2012 and $6 million at December 31, 2011 of medical benefit (health and welfare) component for 401h accounts to fund a portion of the other retirement benefits.
(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.

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

	Fair value measurements using significant unobservable inputs - Level 3 (1) December 31, 2012			
In millions	**Global hedged equity**	**Absolute return**	**Private capital**	**Total**
Assets:				
Beginning balance	$30	$34	$25	$89
Gains included in changes in net assets	3	2	3	8
Purchases	15	0	0	15
Sales	(10)	0	(5)	(15)
Ending balance	$38	$36	$23	$97

	December 31, 2011			
In millions	**Global hedged equity**	**Absolute return**	**Private capital**	**Total**
Assets:				
Beginning balance	$35	$30	$22	$87
(Losses) gains included in changes in net assets	(1)	1	5	5
Purchases	2	3	1	6
Sales	(6)	0	(3)	(9)
Ending balance	$30	$34	$25	$89

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

Derivative Instruments

The following table summarizes, by level within the fair value hierarchy, our derivative assets and liabilities that were carried at fair value on a recurring basis in our Consolidated Statements of Financial Position as of the dates presented.

	December 31, 2012		December 31, 2011	
In millions	**Assets** (1)	**Liabilities**	**Assets** (1)	**Liabilities**
Natural gas derivatives				
Quoted prices in active markets (Level 1)	$8	$(45)	$11	$(145)
Significant other observable inputs (Level 2)	96	(30)	229	(67)
Netting of cash collateral	33	36	32	115
Total carrying value (2) (3)	**$137**	**$(39)**	**$272**	**$(97)**
Interest rate derivatives				
Significant other observable inputs (Level 2)	**$3**	**$0**	**$13**	**$(13)**

(1) $4 million of premium at December 31, 2012 and $3 million at December 31, 2011 associated with weather derivatives have been excluded as they are accounted for based on intrinsic value.
(2) There were no material unobservable inputs (Level 3) for any of the periods presented.
(3) There were no material transfers between Level 1, Level 2, or Level 3 for any of the periods presented.

Money Market Funds

At December 31, 2012 and 2011, the fair values of our money market funds, which were recorded within short-term and long-term investments, were as follows:

In millions	**2012**	**2011**
Money market funds (1)	$66	$59

(1) Carried at fair value and classified as Level 1 within the fair value hierarchy.

Debt

Our long-term debt is recorded at amortized cost, with the exception of Nicor Gas' first mortgage bonds, which are recorded at acquisition date fair 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. The following table presents the amortized cost and fair value of our long-term debt for the following periods.

	As of December 31,	
In millions	**2012**	**2011**
Long-term debt amortized cost, including current portions of long-term debt and capital leases (1)	$3,553	$3,578
Long-term debt fair value (1) (2)	$4,057	$3,938

(1) Includes the debt assumed in the Nicor merger with a carrying value of $590 million as of December 31, 2012 and $599 million as of December 31, 2011.
(2) Valued using Level 2 inputs.

Note 5 - Derivative Instruments

Derivative 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 instruments, including 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 instruments and energy-related contracts to manage natural gas price, interest rate, weather, automobile fuel price and foreign currency risks:

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

Certain of our derivative instruments contain 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. As of December 31, 2012 and 2011 for agreements with such features, derivative instruments with liability fair values totaled $39 million and $110 million, respectively, for which we had posted no collateral to our counterparties. In addition, our energy marketing receivables and payables, which also have credit-risk-related or other contingent features, are discussed in Note 2. Our derivative instrument activities are included within operating cash flows as an adjustment to net income of $72 million in 2012, $(17) million in 2011 and $7 million in 2010.

On December 6, 2012, we entered into a ten-year, $200 million 1.78% fixed-rate forward-starting interest rate swap to hedge any potential interest rate volatility prior to an anticipated issuance of senior notes during the second quarter 2013. We have designated the forward-starting interest rate swap, which will mature on the debt issuance date, as a cash flow hedge.

In May 2011, we entered into interest rate swaps related to the $300 million outstanding of 6.4% senior notes due in July 2016 that effectively converted $250 million from a fixed rate to a variable rate obligation. On September 6, 2012 we settled this $250 million fixed-rate to floating-rate interest rate swap.

The fair values of our interest rate swaps were reflected as a long-term derivative asset of $3 million and no short-term liability at December 31, 2012 and a long-term derivative asset of $13 million and a short-term liability of $13 million at December 31, 2011. For more information on our debt, see Note 8.

The following table summarizes the various ways in which we account for our derivative instruments and the impact on our consolidated financial statements:

Accounting Treatment	Recognition and Measurement	
	Statements of Financial Position	**Income Statement**
Cash flow hedge	Derivative carried 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 OCI (loss)	Effective portion of the gain or loss on the derivative instrument is reclassified out of accumulated OCI (loss) and into earnings when the hedged transaction affects earnings
Fair value hedge	Derivative carried at fair value Changes in fair value of the hedged item are recorded as adjustments to the carrying amount of the hedged item	Gains or losses on the derivative instrument and the hedged item are recognized in earnings. As a result, to the extent the hedge is effective, the gains or losses will offset and there is no impact on earnings. Any hedge ineffectiveness will impact earnings
Not designated as hedges	Derivative carried at fair value	Realized and unrealized gains or losses on the derivative instrument are recognized in earnings
	Distribution operations' gains and losses on derivative instruments are deferred as regulatory assets or liabilities until included in cost of goods sold	The gain or loss on these derivative instruments is reflected in natural gas costs and is ultimately included in billings to customers

Quantitative Disclosures Related to Derivative Instruments

As of December 31, 2012 and 2011, our derivative 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, 2012 and 2011, we had net long natural gas contracts outstanding in the following quantities:

Natural gas contracts

In Bcf	**December 31, 2012** (1) (2)	**December 31, 2011** (2)
Hedge designation:		
Cash flow hedges	6	5
Not designated as hedges	96	186
Total hedges	102	191
Hedge position:		
Short position	(1,955)	(1,680)
Long position	2,057	1,871
Net long position	102	191

(1) Approximately 99% of these contracts have durations of two years or less and the remaining 1% expire in 3 to 6 years.
(2) Volumes related to Nicor Gas exclude variable-priced contracts, which are accounted for as derivatives, but whose fair values are not directly impacted by changes in commodity prices.

Derivative Instruments on the Consolidated Statements of Financial Position

In accordance with regulatory requirements, gains and losses on derivative instruments used at Nicor Gas and Elizabethtown Gas in our distribution operations segment were reflected in accrued natural gas costs within our Consolidated Statements of Financial Position. The following amounts represent realized losses for the year ended December 31.

In millions	**2012**	**2011**
Nicor Gas	$35	$3
Elizabethtown Gas	$28	$27

The following table presents the fair value and Consolidated Statements of Financial Position classification of our derivative instruments:

In millions	**Statements of financial position location** (1) (2)	**December 31, 2012**	**2011**
Designated as cash flow and fair value hedges			
Asset Instruments			
Current natural gas contracts	Derivative instruments assets and liabilities - current portion	$1	$9
Noncurrent natural gas contracts	Derivative instruments assets and liabilities	3	0
Interest rate swap agreements	Derivative instruments assets - current portion	0	13
Liability Instruments			
Current natural gas contracts	Derivative instruments assets and liabilities - current portion	(2)	(12)
Interest rate swap agreements	Derivative instruments liabilities - current portion	0	(13)
Total		2	(3)
Not designated as cash flow hedges			
Asset Instruments			
Current natural gas contracts	Derivative instruments assets and liabilities - current portion	394	706
Noncurrent natural gas contracts	Derivative instruments assets and liabilities	45	133
Liability Instruments			
Current natural gas contracts	Derivative instruments assets and liabilities - current portion	(355)	(689)
Noncurrent natural gas contracts	Derivative instruments assets and liabilities	(50)	(116)
Total		34	34
Total derivative instruments		$36	$31

(1) These amounts are netted within our Consolidated Statements of Financial Position for amounts which we have netting arrangements with the counterparties.
(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 do not include cash collateral held on deposit in broker margin accounts of $69 million as of December 31, 2012 and $147 million as of December 31, 2011. 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 instruments in the recurring fair values table of Note 4.

Derivative Instruments on the Consolidated Statements of Income

The following table presents the gain or (loss) on derivative instruments in our Consolidated Statements of Income for the years ended December 31, 2012, 2011 and 2010.

	December 31,		
In millions	**2012**	**2011**	**2010**
Designated as cash flow hedges			
Natural gas contracts - loss reclassified from OCI into cost of goods sold	$(3)	$(6)	$(16)
Interest rate swaps - ineffectiveness recorded as an offset to interest expense	(3)	3	0
Not designated as hedges			
Natural gas contracts - net fair value adjustments recorded in operating revenues (1)	34	40	(1)
Natural gas contracts - net fair value adjustments recorded in cost of goods sold (2)	0	0	(2)
Natural gas contracts - net fair value adjustments recorded in operation and maintenance expense	(4)	(4)	0
Total gains (losses) on derivative instruments	$24	$33	$(19)

(1) Associated with the fair value of existing derivative instruments at December 31, 2012, 2011 and 2010.
(2) Excludes losses recorded in cost of goods sold associated with weather derivatives of $14 million for the year ended December 31, 2012, $9 million for the year ended December 31, 2011 and $27 million for the year ended December 31, 2010.

Any amounts recognized in operating income, related to ineffectiveness or due to a forecasted transaction that is no longer expected to occur, were immaterial for the years ended December 31, 2012, 2011 and 2010.

Our expected net loss to be reclassified from OCI into cost of goods sold, operation and maintenance expense, and operating revenues and recognized in our Consolidated Statements of Income over the next 12 months is $1 million. These pre-tax deferred losses are recorded in OCI related to natural gas derivative contracts associated with retail operations' and with Nicor Gas' system use. The expected losses are based upon the fair values of these financial instruments at December 31, 2012.

Note 6 - 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 defined benefit retirement plans. Further, we have an Investment Policy (the Policy) for our pension and other retirement benefit plans whose goal is 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 plans' assets are 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 funded status. Changes in the projected benefit obligation (PBO) and accumulated postretirement benefit obligation (APBO) are mainly driven by the assumed discount rate. Additionally, equity market performance has a significant effect on our market-related value of plan assets (MRVPA), which is used by the AGL Plan, to determine the expected return on the plan assets component of net annual pension cost. The MRVPA is a calculated value. Gains and losses on plan assets are spread through the MRVPA based on the five-year smoothing weighted average methodology.

Pension Benefits

We sponsor the AGL Plan, which is a tax-qualified defined benefit retirement plan for our eligible employees. A defined benefit plan specifies the amount of benefits an eligible participant eventually will receive using information about the participant, including information related to the participant's earnings history, years of service and age. In 2012, we also sponsored two other tax-qualified defined benefit retirement plans for our eligible employees, the Nicor Plan and the NUI Plan. Effective as of December 31, 2012, the NUI Plan and the Nicor Plan were merged into the AGL Plan. The participants of the Nicor and NUI plans described below are now being offered the AGL Plan.

We generally calculate the benefits under the AGL Plan based on age, years of service and pay. The benefit formula for the AGL Plan is currently a career average earnings formula. Participants who were employees as of July 1, 2000 and who were at least 50 years of age as of that date earned benefits until December 31, 2010 under a final average pay formula. Participants who were employed as of July 1, 2000, but did not satisfy the age requirement to continue under the final average earnings formula, transitioned to the career average earnings formula on July 1, 2000.

Effective January 1, 2012, the AGL Plan was frozen with respect to participation for non-union employees hired on or after that date. Such employees are entitled to employer provided benefits under their defined contribution plan, that exceed defined contribution benefits for employees who participate in the defined benefit plan.

The Nicor Plan is a noncontributory defined benefit pension plan covering substantially all union and non-union employees of Nicor Gas and its affiliates that adopted the Nicor Plan, hired prior to 1998. Pension benefits are based on years of service and the highest average salary for management employees and job level for collectively bargained employees (referred to as pension bands). The benefit obligation related to collectively bargained benefits considers the past practice of regular benefit increases.

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

Defined Benefit Welfare Benefits

Until December 31, 2012, we sponsor two defined benefit retiree health care plans for our eligible employees, the Health and Welfare Plan for Retirees and Inactive Employees of AGL Resources Inc. (AGL Welfare Plan) and the Nicor Gas Welfare Benefit Plan (Nicor Welfare Plan). Eligibility for these benefits is based on age and years of service. Effective December 31, 2012, the Nicor Welfare Plan was terminated and as of January 1, 2013, all participants under that plan became eligible to participate in the AGL Welfare Plan. This change in plan participation eligibility did not affect the benefit terms. The Nicor Welfare Plan benefits described below are now being offered to such participants under the AGL Welfare Plan.

The AGL Welfare Plan includes medical coverage for all eligible AGL Resources employees who were employed as of June 30, 2002, if they reach the plan's retirement age while working for us. In addition, the AGL Welfare Plan provides life insurance for all employees if they have ten years of service at retirement. The state regulatory commissions have approved phase-in plans that defer a portion of the related benefits expense for future recovery. The AGL Welfare Plan terms include a limit on the employer share of costs at limits based on the coverage tier, plan elected and salary level of the employee at retirement.

Medicare eligible retirees covered by the AGL Welfare Plan, including all of those at least age 65, receive benefits through our contribution to a retiree health reimbursement arrangement account. Additionally, on the pre-65 medical coverage of the AGL Welfare Plan our expected cost is determined by a retiree premium schedule based on salary level and years of service. Due to the cap, there is no impact on the periodic benefit cost or on our accumulated projected benefit obligation for the AGL Welfare Plan for a change in the assumed healthcare cost trend.

The plan provisions that are applicable to prior participants in the Nicor Welfare Plan include health care and life insurance benefits to eligible retired employees and include a limit on the employer share of cost for employees hired after 1982.

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 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. Prescription drug coverage for the Nicor Gas Medicare-eligible population changed, effective January 1, 2013, from an employer-sponsored prescription drug plan with the Retiree Drug Subsidy (RDS) to an Employer Group Waiver Plan (EGWP). The EGWP replaces the employer sponsored prescription drug plan. The expected savings is estimated to be approximately 12% of total Medicare eligible liability.

We recorded a regulatory asset for anticipated future recoveries of $215 million as of December 31, 2012 and $291 million as of December 31, 2011. In addition, we recorded a regulatory liability of $3 million as of December 31, 2012 and $19 million as of December 31, 2011 for our expected expenses under the AGL Welfare Plan and the Nicor Gas Welfare Benefit Plan.

We also have a separate unfunded supplemental retirement health care plan that provides health care and life insurance benefits to employees of discontinued businesses. This plan is noncontributory with defined benefits.

Net plan expenses were immaterial in 2012 and 2011. The APBO associated with this plan was $3 million at December 31, 2012, and $3 million at December 31, 2011.

Assumptions

We consider a variety of factors in determining and selecting our assumptions for the discount rate at December 31. We based our discount rate at December 31, 2012 on an above mean yield curve provided by our actuaries that is derived from a portfolio of high quality (rated AA or better) corporate bonds that have a yield higher than the regression mean curve and the equivalent annuity cash flows separately for each plan. The following tables present details about our pension and other retirement plans.

	Pension plans		Other retirement plans	
Dollars in millions	**2012**	**2011**	**2012**	**2011**
Change in plan assets				
Fair value of plan assets, January 1,	$754	$344	$67	$71
Plan assets acquired in Nicor merger	0	388	0	0
Actual return on plan assets	101	(7)	10	(3)
Employee contributions	0	0	1	0
Employer contributions	42	58	17	8
Benefits paid	(59)	(28)	(19)	(9)
Medicare Part D reimbursements	0	0	1	0
Plan curtailment and settlements	(1)	(1)	0	0
Fair value of plan assets, December 31,	$837	$754	$77	$67
Change in benefit obligation				
Benefit obligation, January 1,	$968	$531	$397	$107
Benefit obligations acquired in Nicor merger	0	345	0	273
Service cost	28	14	4	1
Interest cost	44	29	17	6
Actuarial loss (gain)	66	78	(22)	18
Plan amendments	0	0	(25)	0
Medicare Part D reimbursements	0	0	1	1
Benefits paid	(59)	(28)	(19)	(9)
Employee contributions	0	0	1	0
Plan curtailment and settlements	(1)	(1)	0	0
Benefit obligation, December 31,	$1,046	$968	$354	$397
Funded status at end of year	$(209)	$(214)	$(277)	$(330)
Amounts recognized in the Consolidated Statements of Financial Position consist of				
Long-term asset	$33	$26	$0	$0
Current liability	(2)	(2)	(12)	(14)
Long-term liability	(240)	(238)	(265)	(316)
Total liability at December 31,	$(209)	$(214)	$(277)	$(330)
Accumulated benefit obligation (2)	$983	$910	n/a	n/a
Supplemental information for underfunded pension plans included above as of December 31, 2012:				
Aggregate benefit obligation	n/a	$604	n/a	n/a
Aggregate accumulated benefit obligation	n/a	570	n/a	n/a
Aggregate fair value of plan assets	n/a	363	n/a	n/a
Assumptions used to determine benefit obligations				
Discount rate	4.2%	4.6%	4.0%	4.5%
Rate of compensation increase	3.7%	3.7%	3.7%	3.7%
Pension band increase (1)	2.0%	2.0%	n/a	n/a

(1) Only applicable to the Nicor Gas pension plan.
(2) ABO differs from the projected benefit obligation in that the ABO excludes the effect of salary and wage increases.

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

	Pension plans			Other retirement plans		
Dollars in millions	**2012**	**2011**	**2010**	**2012**	**2011**	**2010**
Service cost	$28	$14	$11	$4	$1	$0
Interest cost	44	29	27	16	6	6
Expected return on plan assets	(64)	(33)	(28)	(5)	(5)	(5)
Net amortization of prior service credit	(2)	(2)	(2)	(3)	(4)	(4)
Recognized actuarial loss	34	14	10	9	2	2
Net periodic benefit cost	$40	$22	$18	$21	$0	$(1)
Assumptions used to determine benefit costs						
Discount rate (1)	4.6%	5.4%	6.0%	4.5%	5.2%	5.8%
Expected return on plan assets (1)	8.4%	8.5%	8.8%	8.5%	8.2%	8.8%
Rate of compensation increase (1)	3.7%	3.7%	3.7%	3.8%	3.7%	3.7%
Pension band increase (1) (2)	2.0%	2.0%	n/a	n/a	n/a	n/a

(1) Rates are presented on a weighted average basis.
(2) Only applicable to the Nicor Gas pension plan.

A portion of the net benefit cost or credit related to these plans has been capitalized as a cost of constructing gas distribution facilities and the remainder is included in gas distribution operation and maintenance expense, net of amounts charged to affiliates.

Assumptions used to determine the 2012 health care benefit cost for the Nicor Gas Welfare Benefit Plan were as follows:

	2012	**2011**
Health care cost trend rate assumed for next year	8.4%	8.6%
Ultimate rate to which the cost trend rate is assumed to decline	4.5%	4.5%
Year that reaches ultimate trend rate	2030	2030

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

Dollars in millions	**Effect on service and interest cost**	**Effect on benefit obligation**
1% Health care cost trend rate increase	$1	$17
1% Health care cost trend rate decrease	(1)	(14)

As a result of a cap on expected cost for the AGL Welfare Plan, a one-percentage-point increase or decrease in the assumed health care trend does not materially affect periodic benefit cost or accumulated benefit obligation of the Plan.

The following table presents the amounts not yet reflected in net periodic benefit cost and included in net regulatory assets and accumulated OCI as of December 31, 2012 and 2011:

	Net regulatory assets		**Accumulated OCI**		**Total**	
In millions	**Pension plan**	**Other retirement plans**	**Pension plan**	**Other retirement plans**	**Pension plan**	**Other retirement plans**
December 31, 2012:						
Prior service credit	$0	$(24)	$(11)	$(2)	$(11)	$(26)
Net loss	146	83	324	52	470	135
Total	$146	$59	$313	$50	$459	$109
December 31, 2011:						
Prior service cost (credit)	$1	$1	$(13)	$(4)	$(12)	$(3)
Net loss	162	119	312	51	474	170
Total	$163	$120	$299	$47	$462	$167

The 2013 estimated amortization out of regulatory assets or accumulated OCI for these plans are set forth in the following table.

In millions	Net Regulatory Asset		Accumulated OCI		Total	
	Pension plans	Other retirement plans	Pension plans	Other retirement plans	Pension plans	Other retirement plans
Amortization of prior service credit	$0	$(3)	$(2)	$(2)	$(2)	$(5)
Amortization of net loss	9	6	24	3	33	8

The following table presents the gross benefit payments expected for the years ended December 31, 2013 through 2022 for our pension and other retirement plans. There will be benefit payments under these plans beyond 2022.

In millions	Pension plans	Other retirement plans
2013	$57	$19
2014	60	20
2015	62	21
2016	65	21
2017	68	22
2018-2022	377	121

Contributions

Our employees generally do not contribute to these pension and other retirement plans, however, Nicor Gas and pre-65 AGL retirees make nominal contributions to their health care plan. 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 and established a 100% funding target (over a 7-year amortization period) for plan years beginning after December 31, 2007. In 2012 we contributed $40 million to the AGL Plan and the NUI Plan. In 2011 we contributed $56 million to the AGL Plan and the NUI Plan. No contributions were made to the Nicor Plan in 2012 or 2011. For more information on our 2013 contributions to our pension plans, see Note 11.

Employee Savings Plan Benefits

We sponsor defined contribution benefit plans that allow eligible participants to make contributions to their accounts up to specified limits. Under these plans, our matching contributions to participant accounts were $14 million in 2012, $7 million in 2011 and $7 million in 2010.

Note 7 - Stock-Based Compensation

General

The AGL Resources Inc. Omnibus Performance Incentive Plan, as amended and restated, and the Long-Term Incentive Plan (1999) provide for the grant of incentive and nonqualified stock options, stock appreciation rights, shares of restricted stock, restricted stock units, performance cash awards and other stock-based awards to officers and key employees. Under the Omnibus Performance Incentive Plan, as of December 31, 2012, the number of shares issuable upon exercise of outstanding stock options, warrants & rights is 823,200 shares. Under the Long-Term Incentive Plan (1999) as of December 31, 2012, the number of shares issuable upon exercise of outstanding stock options, warrants & rights is 1,184,890 shares. The maximum number of shares available for future issuance under the Omnibus Performance Incentive Plan is 4,609,105 shares, which includes 1,657,910 shares previously available under the Nicor Inc. 2006 Long term incentive plan, as amended, pursuant to NYSE rules. No further grants will be made from the Long-Term Incentive Plan (1999) except for reload options that may be granted pursuant to the terms of certain outstanding options.

Accounting Treatment and Compensation Expense

We measure and recognize stock-based compensation expense for our stock-based awards over the requisite service period in our financial statements based on the estimated fair value at the date of grant for our stock-based awards using the modified prospective method. These stock awards include:

- stock options
- stock awards
- performance units (restricted stock units, performance share 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 requisite service period when recognizing compensation expense. These estimates are adjusted to the extent that actual forfeitures differ, or are expected to materially differ, from such estimates. 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 have granted 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 closing price per share of AGL Resources common stock for the trading day immediately preceding the grant date, 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	2012	2011	2010
Compensation costs (1)	$9	$14	$11
Income tax benefits (1)	1	1	2
Excess tax benefits (2)	1	1	2

(1) Recorded in our Consolidated Statements of Income.
(2) Recorded in our Consolidated Statements of Financial Position.

Incentive and Nonqualified Stock Options

The stock options we granted 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, 2012, we had no unrecognized compensation costs related to stock options and this amount was immaterial as of December 31, 2011. Cash received from stock option exercises for 2012 was $7 million, and the income tax benefits from stock option exercises were $1 million. Cash received from stock option exercises for 2011 was $11 million, and the income tax benefit from stock option exercises was $1 million. The following tables summarize activity related to stock options for key employees and non-employee directors. As used in the table, intrinsic value for options means the difference between the current market value and the grant price.

Stock Options

	Number of options	Weighted average exercise price	Weighted average remaining life (in years)	Aggregate intrinsic value (in millions)
Outstanding - December 31, 2009	2,551,568	$34.48		
Granted	0	0		
Exercised	(296,008)	31.33		
Forfeited	(26,448)	37.85		
Outstanding - December 31, 2010	2,229,112	$34.85		
Granted	1,685	42.19		
Exercised	(383,646)	31.11		
Forfeited	(23,997)	37.70		
Outstanding - December 31, 2011	1,823,154	$35.61	4.6	
Granted	0	0	0.0	
Exercised	(234,844)	32.07	3.2	
Forfeited	(59,720)	37.34	4.0	
Outstanding - December 31, 2012	1,528,590	$36.09	3.7	$6
Exercisable - December 31, 2012	1,528,590	$36.09	3.7	$6
Exercisable - December 31, 2011	1,747,656	$35.81	4.5	$11
Exercisable - December 31, 2010	1,799,334	$34.92	4.9	$4

Information about exercisable and outstanding options as of December 31, 2012, is as follows.

	Options exercisable and outstanding		
Range of Exercise Prices	Number of options	Weighted average remaining contractual life (in years)	Weighted average exercise price
$26.31 to $30.69	38,500	0.6	$26.86
$30.70 to $35.08	335,048	3.9	$32.25
$35.09 to $39.46	1,115,866	3.7	$37.38
$39.47 to $43.85	39,176	3.9	$41.25
Outstanding	1,528,590	3.7	$36.09

We measure compensation expense related to stock options based on the fair value of these awards at their date of grant using the Black-Scholes option-pricing model. There were no options granted in 2010 and 2012, and the number of shares granted in 2011 was immaterial.

We use shares purchased under our 2006 share repurchase program to satisfy exercises to the extent that repurchased shares are available. Otherwise, we issue new shares from our authorized common stock.

Performance Units

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

Restricted Stock Units In general, a restricted stock unit is an award that represents the opportunity to receive a specified number of shares of our common stock, subject to the achievement of certain pre-established performance criteria. In 2012, we granted 186,300 restricted stock units to certain employees, of which 179,710 of these units were outstanding as of December 31, 2012. These restricted stock units had a performance measurement period that ended December 31, 2012. Because the performance measure related to a basic earnings per common share attributable to AGL Resources Inc. common shareholders goal was not met, the performance criteria were not achieved. As such, the related restricted stock awards will not occur in 2013.

Performance Share Unit Awards A performance share unit award represents the opportunity to receive cash and shares subject to the achievement of certain pre-established performance criteria. We granted performance share unit awards to certain officers. These awards have a performance measure that relates to the Company's relative total shareholder return relative to a group of peer companies. There is no recorded liability for the 2010 grants, as the performance criteria were not achieved. The recorded liability and maximum potential liability related to the 2012 and 2011 grants are as follows:

In millions	Measurement period end date	Accrued at Dec. 31, 2012	Maximum aggregate payout
Granted in 2011	Dec. 31, 2013	$4	$11
Granted in 2012	Dec. 31, 2014	$3	$16

Stock and Restricted Stock Awards

The compensation cost of both stock awards and restricted stock awards is equal to the grant date fair value of the awards, recognized over the requisite service period. No other assumptions are used to value the awards. We refer to restricted stock as an award of our common stock that is subject to time-based vesting or achievement of performance measures. Restricted stock awards are subject to certain transfer restrictions and forfeiture upon termination of employment.

Stock Awards - Non-Employee Directors Non-employee director compensation may be paid in shares of our common stock in connection with initial election, the annual retainer, and chair retainers, as applicable. Stock awards for non-employee directors are 100% vested and nonforfeitable as of the date of grant. During 2012 we issued 32,723 shares with a weighted average fair value of $39.43 to our non-employee directors.

Restricted Stock Awards - Employees The following table summarizes the restricted stock awards activity for our employees during the last two years.

	Shares of restricted stock	Weighted average remaining vesting period (in years)	Weighted average fair value
Outstanding - December 31, 2010 (1)	400,900		$30.80
Issued	311,600		39.48
Forfeited	(25,784)		36.22
Vested	(209,362)		34.68
Outstanding - December 31, 2011 (1) (2)	477,354	2.6	$34.40
Issued	268,840	3.0	40.08
Forfeited	(28,829)	2.0	39.07
Vested	(214,274)	0.0	36.45
Outstanding - December 31, 2012 (1) (2)	503,091	1.8	$39.44

(1) Subject to restriction.
(2) Includes 82,222 restricted shares with nonforfeitable dividend rights.

Employee Stock Purchase Plan (ESPP)

We have a nonqualified, broad based ESPP for all eligible employees. As of December 31, 2012, there were 224,073 shares available for future issuance under this plan. Employees may purchase shares of our common stock in quarterly intervals at 85% of fair market value, and we record an expense for the 15% purchase price discount. Employee ESPP contributions may not exceed $25,000 per employee during any calendar year.

	2012	2011	2010
Shares purchased on the open market	108,132	65,843	60,017
Average per-share purchase price	$38.96	$40.55	$37.07
Total purchase price discount	$618,278	$401,346	$333,639

Note 8 - Debt and Credit Facilities

Our financing activities, including long-term and short-term debt, are subject to customary approval or review by state and federal regulatory bodies. Our wholly-owned subsidiary, AGL Capital, was established to provide for our ongoing financing needs through a commercial paper program, the issuance of various debt and hybrid securities and other financing arrangements. We fully and unconditionally guarantee all debt issued by AGL Capital. Nicor Gas is not permitted by regulation to make loans to affiliates or utilize AGL Capital for its financing needs.

The following table provides maturity dates, year-to-date weighted average interest rates and amounts outstanding for our various debt securities and facilities that are included in our Consolidated Statements of Financial Position.

		December 31, 2012		December 31, 2011	
Dollars in millions	**Year(s) due**	**Weighted average interest rate** (1)	**Outstanding**	**Weighted average interest rate** (1)	**Outstanding**
Short-term debt					
Commercial paper - AGL Capital (2)	2013	0.5%	$1,063	0.4%	$869
Commercial paper- Nicor Gas (2)	2013	0.4	314	0.4	452
Total short-term debt		**0.5%**	**$1,377**	**0.4%**	**$1,321**
Current portion of long-term debt and capital leases					
Current portion of long-term debt	2013	4.6	225	8.3	15
Current portion of capital leases	2013	4.9	1	4.9	2
Total current portion of long-term debt and capital leases		**4.6%**	**$226**	**8.0%**	**$17**
Long-term debt - excluding current portion					
Senior notes	2015-2041	5.1%	$2,325	5.4%	$2,550
First mortgage bonds	2016-2038	5.6	500	5.6	500
Gas facility revenue bonds	2022-2033	1.2	200	1.2	200
Medium-term notes	2017-2027	7.8	181	7.8	181
Total principal long-term debt		5.0%	$3,206	5.7%	$3,431
Fair value adjustments (3)	2016-2038	n/a	103	n/a	112
Unamortized debt premium, net	n/a	n/a	18	n/a	18
Total non-principal long-term debt		n/a	121	n/a	$130
Total long-term debt			**$3,327**		**$3,561**
Total debt			**$4,930**		**$4,899**

(1) Interest rates are calculated based on the daily weighted average balance for the applicable category outstanding for the twelve months ended December 31, 2012 and 2011.

(2) As of December 31, 2012, the weighted average interest rates on our commercial paper borrowings were 0.5% for AGL Capital and 0.4% for Nicor Gas.

(3) See Note 4 for additional information on our fair value measurements.

Short-term Debt

Our short-term debt at December 31, 2012 and 2011 was composed of borrowings under our commercial paper programs.

Commercial Paper Programs We maintain commercial paper programs at AGL Capital and at Nicor Gas that consist of short-term, unsecured promissory notes that are used in conjunction with cash from operations to fund our seasonal working capital requirements. Working capital needs fluctuate during the year and are highest during the injection period in advance of the Heating Season. The Nicor Gas commercial paper program supports working capital needs at Nicor Gas, while all of our other subsidiaries, and SouthStar, participate in the AGL Capital commercial paper program. At December 31, 2012, our commercial paper maturities ranged from 2 to 93 days.

AGL Credit Facility On November 10, 2011, AGL Capital amended and restated its revolving credit facility to extend the maturity date to November 10, 2016 and to increase the revolving credit commitments to $1.3 billion. This credit facility can be drawn upon to support the AGL Capital commercial paper program and to provide the flexibility to meet ongoing working capital and other general purpose needs. The interest rate payable on borrowings under the AGL Credit Facility is calculated either at the alternative base rate, plus an applicable margin, or LIBOR, plus an applicable interest margin. The applicable interest margin used in both interest rate calculations will vary according to AGL Capital's current credit ratings. At December 31, 2012 and 2011, there were no outstanding borrowings under this facility.

Nicor Gas Credit Facility On December 15, 2011, Nicor Gas entered into a $700 million revolving credit facility, which matures on December 15, 2016. The Nicor Gas Credit Facility replaced its previous three-year credit facility and the 364-day facility and can be drawn upon to support the Nicor Gas commercial paper program and to provide the flexibility to meet ongoing working capital and other general purpose needs. The interest rate payable on borrowings under the Nicor Gas Credit Facility is calculated either at the alternative base rate, plus an applicable interest margin, or LIBOR, plus an applicable interest margin. The applicable interest margin used in both interest rate calculations will vary according to Nicor Gas' current credit ratings. At December 31, 2012 and 2011, there were no outstanding borrowings under this facility.

Current Portion of Long-term Debt and Capital Leases Our current portion of long-term debt at December 31, 2012 and 2011 was composed of the current portions of our long-term debt and capital lease obligations. Our capital leases consist primarily of a sale/leaseback transaction of gas meters and other equipment that was completed in 2002 by Florida City Gas and expires in the second quarter 2013. Based on the terms of the lease agreement, Florida City Gas is required to insure the leased equipment during the lease term. In the second quarter 2012, Florida City Gas had the option to purchase the leased meters from the lessor at their fair market value, but did not exercise this option.

Long-term Debt

Our long-term debt at December 31, 2012 and 2011 consisted of medium-term notes: Series A, Series B, and Series C, which we issued under an indenture dated December 1, 1989; senior notes; first mortgage bonds; and gas facility revenue bonds. Some of these issuances were completed in the private placement market. In determining that those specific bonds qualify for exemption from registration under Section 4(2) of the Securities Act of 1933, we relied on the facts that the bonds were offered only to a limited number of large institutional investors and each institutional investor that purchased the bonds represented that it was purchasing the bonds for its own account and not with a view to distribute them. We fully and unconditionally guarantee all of our senior notes. Additionally, substantially all of Nicor Gas' properties are subject to the lien of the indenture securing its first mortgage bonds.

The majority of our long-term debt matures after fiscal year 2017. The annual maturities of our long-term debt for the next five years and thereafter are as follows:

Year	**Amount** *(in millions)*
2013	$225
2014	0
2015	200
2016	545
2017	22
Thereafter	2,439
Total	$3,431

Senior Notes There were no senior note issuances in 2012. We had the following senior note issuances in 2011:

	Issuance Date	**Amount** *(in millions)*	**Maturity date**	**Interest rate**
Public offering (1)	March 16, 2011	$500	March 15, 2041	5.9%
Public offering (2)	September 15, 2011	$200	March 15, 2041	5.9%
Public offering (2)	September 15, 2011	$300	September 15, 2021	3.5%
Private placement - Series A (2)	October 27, 2011	$120	October 27, 2016	1.9%
Private placement - Series B (2)	October 27, 2011	$155	October 27, 2018	3.5%

(1) The net proceeds were used to repay our commercial paper and to repay our $300 million in senior notes that matured on January 14, 2011. The remaining proceeds were used for the cash consideration and expenses incurred in connection with the Nicor merger.
(2) The net proceeds were used to pay a portion of the cash consideration and expenses incurred in connection with the Nicor merger.

Following our issuances of these senior notes, we terminated the Bridge Facility.

Interest Rate Swaps On December 6, 2012, we entered into a ten-year, $200 million 1.78% fixed-rate forward-starting interest rate swap to hedge any potential interest rate volatility prior to an anticipated issuance of senior notes during the second quarter 2013. We have designated the forward-starting interest rate swap, which will mature on the forecasted debt issuance date, as a cash flow hedge.

In May 2011, we entered into interest rate swaps related to the $300 million outstanding of 6.4% senior notes due in July 2016. These interest rate swaps effectively converted $250 million from a fixed rate to a variable rate obligation. On September 6, 2012 we settled our $250 million fixed-rate to floating-rate interest rate swap, which resulted in our receipt of a $17 million cash payment that is classified as a financing activity in the Consolidated Statements of Cash Flows. Upon settlement of the swap, we began amortizing the accumulated fair value increase to the senior notes, net of ineffectiveness, as a reduction to interest expense over the remaining term of the senior notes.

First Mortgage Bonds As a result of the merger, we acquired the first mortgage bonds of Nicor Gas, which at December 31, 2012 and 2011 had principal balances totaling $500 million. Nicor Gas has issued first mortgage bonds through the public and private placement markets.

Gas Facility Revenue Bonds We are party to a series of loan agreements with the New Jersey Economic Development Authority (NJEDA) under which the NJEDA has issued a series of gas facility revenue bonds. These gas revenue bonds are issued by state agencies or counties to investors, and proceeds from the issuance are then loaned to us.

Financial and Non-Financial Covenants

The AGL Credit Facility and the Nicor Gas Credit Facility each include a financial covenant that requires us to maintain a ratio of total debt to total capitalization of no more than 70% at the end of any fiscal month; however, our goal is to maintain these ratios at levels between 50% and 60%. These ratios, as calculated in accordance with the debt covenants, include standby letters of credit and surety bonds and exclude accumulated OCI items related to non-cash pension adjustments, other post-retirement benefits liability adjustments and accounting adjustments for cash flow hedges. Adjusting for these items, the following table contains our debt-to-capitalization ratios for the periods presented, which are within our required and targeted ranges.

	AGL Resources December 31,		Nicor Gas December 31,	
	2012	2011	2012	2011
Debt-to-capitalization ratio	58%	58%	55%	60%

The credit facilities contain 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.

Default Provisions

Our credit facilities and other financial obligations include provisions that, if not complied with, could require early payment or similar actions. The most important default events include:

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

We have no triggering events in our debt instruments that are tied to changes in our specified credit ratings or our stock price and have not entered into any transaction that requires us to issue equity based on credit ratings or other triggering events. We were in compliance with all existing debt provisions and covenants, both financial and non-financial, as of December 31, 2012 and 2011.

Preferred Securities

At December 31, 2012 and 2011, we had 10 million shares of authorized, unissued Class A junior participating preferred stock, no par value, and 10 million shares of authorized, unissued preferred stock, no par value.

Note 9 - Equity

Treasury Shares

Our Board of Directors authorized us to purchase up to 8 million treasury shares through our repurchase plan, which expired on January 31, 2011. This plan was used to offset shares issued under our employee and non-employee director incentive compensation plans and our dividend reinvestment and stock purchase plans. Stock purchases under this plan were made in the open market or in private transactions at times, and in amounts that we deemed appropriate. We held the purchased shares as treasury shares and accounted for them using the cost method. In 2011, we spent $2 million to purchase less than 0.1 million treasury shares at a weighted average price per share of $36.25 and purchased no treasury shares in 2012.

Dividends

Our common shareholders may receive dividends when declared at the discretion of our Board of Directors. Dividends may be paid in cash, stock or other form of payment, and payment of future dividends will depend on our future earnings, cash flow, financial requirements and other factors. As a result of the Nicor merger, AGL Resources shareholders on record as of the close of business on December 8, 2011, received a pro rata dividend for the stub period, accruing from November 19, 2011.

Additionally, we derive a substantial portion of our consolidated assets, earnings and cash flow from the operation of regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to us is subject to regulation. As with most other companies, the payment of dividends is restricted by laws in the states where we conduct business. In certain cases, our ability to pay dividends to our common shareholders is limited by (i) our ability to pay our debts as they become due in the usual course of business and satisfy our obligations under certain financing agreements, including our debt-to-capitalization covenant, (ii) our ability to maintain total assets below total liabilities, and (iii) our ability to satisfy our obligations to any preferred shareholders.

Accumulated Other Comprehensive Loss

Our share of comprehensive income (loss) includes net income plus OCI, which includes changes in fair value of certain derivatives designated as cash flow hedges, certain changes in pension and other retirement benefit plans and reclassifications for amounts included in net income less net income and OCI attributable to the noncontrolling interest. For more information on our derivative instruments, see Note 5. For more information on our pensions and retirement benefit obligations, see Note 6. Our other comprehensive income (loss) amounts are aggregated within our accumulated other comprehensive loss. The following table provides the components of our accumulated other comprehensive loss balances, net of the related tax effects allocated to each component of OCI.

In millions	**Cash flow hedges**	**Retirement benefit plans**	**Accumulated other comprehensive**
As of December 31, 2009	$(2)	$(114)	$(116)
Other comprehensive loss	(5)	(28)	(33)
Purchase of additional 15% ownership interest in SouthStar	(1)	0	(1)
As of December 31, 2010	(8)	(142)	(150)
Other comprehensive loss	(2)	(65)	(67)
As of December 31, 2011	(10)	(207)	(217)
Other comprehensive income (loss)	4	(5)	(1)
As of December 31, 2012	$(6)	$(212)	$(218)

Note 10 - Non-Wholly Owned Entities

Variable Interest Entities

On a quarterly basis we evaluate all of our owner interests to determine if they represent a variable interest entity (VIE) as defined by the authoritative accounting guidance on consolidation, and if so, which party is the primary beneficiary. We have determined that SouthStar, a joint venture owned by us and Piedmont, is the only VIE for which we are the primary beneficiary, which requires us to consolidate its assets, liabilities and Statements of Income. Earnings from SouthStar in 2012, 2011 and 2010 were allocated entirely in accordance with the ownership interests. We account for our ownership of SouthStar in accordance with authoritative accounting guidance which is fully described within Note 2.

SouthStar markets natural gas and related services under the trade name Georgia Natural Gas to customers primarily in Georgia, and under various other trade names to customers in Ohio, Florida and New York. The primary risks associated with SouthStar are discussed in our risk factors included in Item 1A.

The following table illustrates the effect that our 2009 purchase of an additional 15% ownership percentage, which became effective in January 2010, had on our equity.

In millions	Premium on common stock	Accumulated other comprehensive loss	Total
Purchase of additional 15% ownership interest	$(51)	$(1)	$(52)

Our conclusion that SouthStar is a VIE resulted from our equal voting rights with Piedmont not being proportional to our economic obligation to absorb 85% of losses or residual returns from the joint venture. Following are additional factors we considered in determining that we have the power to direct SouthStar's activities that most significantly impact its performance.

Operations

Our wholly owned subsidiary, Atlanta Gas Light, provides the following services in accordance with Georgia Commission authorization that affect SouthStar's operations:

- provides meter reading services for SouthStar's customers in Georgia
- maintains and expands the natural gas infrastructure in Georgia
- markets the benefits of natural gas, performs outreach to residential and commercial developers, offers natural gas appliance rebates and billboard and print advertising, all of which support SouthStar's efforts to maintain and expand its residential, commercial and industrial customers in its largest market, Georgia
- assigns storage and transportation capacity used in delivering natural gas to SouthStar's customers

Liquidity and capital resources

- we provide guarantees for SouthStar's activities with its counterparties, its credit exposure and to certain natural gas suppliers in support of SouthStar's payment obligations
- SouthStar utilizes the AGL Capital commercial paper program for its liquidity and working capital requirements. We support SouthStar's daily cash management activities and assist with ensuring SouthStar has adequate liquidity and working capital resources

Back office functions

- in accordance with our services agreement, we provide services to SouthStar with respect to accounting, information technology, credit and internal controls

SouthStar's financial results are seasonal in nature, with business depending to a great extent on the first and fourth quarters of each year. SouthStar's current assets consist primarily of natural gas inventory, derivative instruments and receivables from its customers. SouthStar also has receivables from us due to its participation in AGL Capital's commercial paper program. See Note 2 for additional discussions of SouthStar's inventories. SouthStar's restricted assets consist of customer deposits and were immaterial as of December 31, 2012 and 2011. SouthStar's current liabilities consist primarily of accrued natural gas costs, other accrued expenses, customer deposits, derivative instruments and payables to us from its participation in AGL Capital's commercial paper program.

As of December 31, 2012, SouthStar's current assets, which approximate fair value, exceeded its current liabilities, long-term assets and other deferred debits, long-term liabilities and other deferred credits by $129 million. SouthStar's other contractual commitments and obligations, including operating leases and agreements with third party providers, do not contain terms that would trigger material financial obligations in the event that such contracts were terminated. As a result, our maximum exposure to a loss at SouthStar is considered to be immaterial. SouthStar's creditors have no recourse to our general credit beyond our corporate guarantees we have provided to SouthStar's counterparties and natural gas suppliers. We have provided no financial or other support that was not previously contractually required. With the exception of our corporate guarantees, we have not entered into any arrangements that could require us to provide financial support to SouthStar.

Price and volume fluctuations of SouthStar's natural gas inventories can cause significant variations in our working capital and cash flow from operations. Changes in our operating cash flows are also attributable to SouthStar's working capital changes resulting from the impact of weather, the timing of customer collections, payments for natural gas purchases and cash collateral amounts that SouthStar maintains to facilitate its derivative instruments.

Cash flows used in our investing activities include capital expenditures for SouthStar for the year ended December 31, of $1 million for 2012, $2 million for 2011 and $3 million for 2010. Cash flows used in our financing activities include SouthStar's distribution to Piedmont for its portion of SouthStar's annual earnings from the previous year. Generally, this distribution occurs in the first or second quarter of each fiscal year. For the year ended December 31, 2012, SouthStar distributed $14 million to Piedmont and $16 million during the year ended December 31, 2011.

The following table provides additional information on SouthStar's assets and liabilities as of the dates presented, which are consolidated within our Consolidated Statements of Financial Position.

	December 31, 2012			December 31, 2011		
In millions	**Consolidated**	**SouthStar** (1)	**%** (2)	**Consolidated**	**SouthStar** (1)	**%** (2)
Current assets	$2,668	$201	8%	$2,746	$210	8%
Long-term assets and other deferred debit	11,473	10	0	11,167	9	0
Total assets	$14,141	$211	1%	$13,913	$219	2%
Current liabilities	$3,338	$62	2%	$3,084	$77	2%
Long-term liabilities and other deferred credits	7,368	0	0	7,490	0	0
Total Liabilities	10,706	62	1	10,574	77	1
Equity	3,435	149	4	3,339	142	4
Total liabilities and equity	$14,141	$211	1%	$13,913	$219	2%

(1) These amounts reflect information for SouthStar and do not include intercompany eliminations and the balances of our wholly owned subsidiary with an 85% ownership interest in SouthStar.
(2) SouthStar's percentage of the amount on our Consolidated Statements of Financial Position.

The following table provides additional information on SouthStar's revenues and expenses for the periods presented, which are consolidated within our Consolidated Statements of Income.

	December 31,	
In millions	**2012**	**2011**
Operating revenues	$576	$689
Operating expenses		
Cost of goods sold	411	526
Operation and maintenance	63	67
Depreciation and amortization	2	2
Taxes other than income taxes	2	2
Total operating expenses	478	597
Operating income	$98	$92

Equity Method Investments

Triton We have an investment in Triton, a cargo container leasing company. Container equipment that is acquired by Triton is accounted for in tranches as defined in Triton's operating agreement, and investors make capital contributions to Triton to invest in each of the tranches. As of December 31, 2012, we had invested in seven tranches established by Triton. For the years ended December 31, 2012 and 2011, income from our equity method investment in Triton of $11 million and $1 million, respectively, are classified as other income on our Consolidated Statements of Income.

Horizon Pipeline We have a 50% owned joint venture with Natural Gas Pipeline Company of America that is regulated by the FERC. Horizon Pipeline operates an approximate 70-mile natural gas pipeline from Joliet, Illinois to near the Wisconsin/Illinois border. Nicor Gas typically contracts for 70% to 80% of the total capacity.

Our investments that are accounted for under the equity method are as follows:

In millions	**2012**	**2011**
Triton	$73	$76
Horizon Pipeline	17	18
Other	9	8
Total	$99	$102

Our net equity investment income for the years ended December 31, 2012, 2011 and 2010, was $13 million, $1 million and less than $1 million, respectively, which is reflected within other income on our Consolidated Statements of Income. The majority of our net equity investment income is attributable to our investment in Triton. For more information on our other income, see Note 2. During 2012 we received distributions of $14 million from our equity investees and an immaterial amount in 2011.

Note 11 - Commitments, Guarantees and Contingencies

We have incurred various contractual obligations and financial commitments in the normal course of our operating and financing activities that are reasonably likely to have a material effect on liquidity or the availability of capital resources. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements. These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related revenue-producing activities. The following table illustrates our expected future contractual payments such as debt and lease agreements, and commitments as of December 31, 2012.

In millions	Total	2013	2014	2015	2016	2017	2018 & thereafter
Recorded contractual obligations:							
Long-term debt (1)	$3,432	$226	$0	$200	$545	$22	$2,439
Short-term debt	1,377	1,377	0	0	0	0	0
Pipeline replacement program costs (2)	121	121	0	0	0	0	0
Environmental remediation liabilities (2)	444	57	62	77	56	40	152
Total	$5,374	$1,781	$62	$277	$601	$62	$2,591
Unrecorded contractual obligations and commitments (3) (8) (9):							
Pipeline charges, storage capacity and gas supply (4)	$2,233	$762	$470	$307	$138	$92	$464
Interest charges (5)	2,430	166	163	153	140	126	1,682
Operating leases (6)	210	32	25	23	21	19	90
Asset management agreements (7)	31	12	8	5	4	2	0
Standby letters of credit, performance / surety bonds (8)	35	29	6	0	0	0	0
Other	8	2	2	2	2	0	0
Total	$4,947	$1,003	$674	$490	$305	$239	$2,236

(1) Excludes the $90 million step up to fair value of first mortgage bonds, $18 million unamortized debt premium and $13 million interest rate swaps fair value adjustment. Includes current portion of long-term debt of $225 million, which matures in April 2013, and current portion of capital leases.
(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 amounts for Nicor Gas and SouthStar gas commodity purchase commitments of 52 Bcf at floating gas prices calculated using forward natural gas prices as of December 31, 2012, and is valued at $186 million. As we do for other subsidiaries, we provide guarantees to certain gas suppliers for SouthStar in support of payment obligations.
(5) Floating rate interest charges are calculated based on the interest rate as of December 31, 2012 and the maturity date of the underlying debt instrument. As of December 31, 2012, we have $53 million of accrued interest on our Consolidated Statements of Financial Position that will be paid in 2013.
(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. Our operating leases are primarily for real estate.
(7) Represent fixed-fee minimum payments for Sequent’s affiliated asset management agreements.
(8) We provide guarantees to certain municipalities and other agencies and certain gas suppliers of SouthStar in support of payment obligations.
(9) Based on the current funding status of the pension plan, we are not required to make a minimum contribution to our plan in 2013.

Substitute Natural Gas

In 2011, Illinois enacted laws that required Nicor Gas and other large utilities in Illinois to elect to either sign contracts to purchase SNG from coal gasification plants to be constructed in Illinois or instead file rate cases with the Illinois Commission in 2012, 2014 and 2016.

On September 30, 2011, Nicor Gas signed an agreement to purchase approximately 25 Bcf of SNG annually for a 10-year term beginning as early as 2015. The agreement required, among other things, the developer to begin construction of the SNG plant by July 1, 2012. The developer did not meet this deadline and, as a result, the agreement automatically terminated.

On October 11, 2011, the Illinois Power Agency (IPA) approved the form of a draft 30-year contract for the purchase by Nicor Gas of 20 Bcf per year of SNG from a second proposed plant beginning as early as 2018. The purchase price of the SNG that may be produced from this proposed coal gasification plant may significantly exceed market prices for natural gas and is expected to be dependent upon a variety of factors, including the developer’s financing, plant construction costs and volumes sold, which are currently not determinable. The Illinois law pertaining to this plant provides that the price paid for SNG purchased from the plant is to be considered prudent and not subject to review or disallowance by the Illinois Commission.

In November 2011, we filed a lawsuit against the IPA and the developer of this second proposed plant contending that the draft contract approved by the IPA does not conform to certain requirements of the enabling legislation. The lawsuit is pending in circuit court in DuPage County, Illinois. In accordance with the enabling legislation, the draft contract approved by the IPA for the second proposed plant was submitted to the Illinois Commission for further approvals by that regulatory body. The final form of contract approved by the Illinois Commission modified the draft contract submitted by the IPA in various respects. We have appealed the Illinois Commission’s decision to the circuit court in Dupage County, Illinois. As a result of pending litigation challenging aspects of the IPA and Illinois Commission decisions regarding the contract terms, we have not yet signed a contract with the developer to purchase SNG from the second proposed plant.

Contingencies and Guarantees

Contingent financial commitments, such as financial guarantees, represent obligations that become payable only if certain predefined events occur 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 have certain subsidiaries that enter into various financial and performance guarantees and indemnities providing assurance to third parties.

Financial guarantees Tropic Equipment Leasing Inc. (TEL), a wholly owned subsidiary, holds our interest in Triton and has an obligation to restore to zero any deficit in its equity account for income tax purposes in the unlikely event that Triton is liquidated and a deficit balance remains. This obligation continues for the life of the Triton partnerships and any payment is effectively limited to the assets of TEL, which were $5 million at December 31, 2012. We believe the likelihood of any such payment by TEL is remote. No liability has been recorded for this obligation.

Indemnities In certain instances, we have undertaken to indemnify current property owners and others against costs associated with the effects and/or remediation of contaminated sites for which we may be responsible under applicable federal or state environmental laws, generally with no limitation as to the amount. These indemnifications relate primarily to ongoing coal tar cleanup, as discussed in Environmental Matters. We believe that the likelihood of payment under our other environmental indemnifications is remote. No liability has been recorded for such indemnifications.

Environmental Matters

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	Probabilistic model cost estimates	Engineering estimates	Amount recorded	Expected costs over next twelve months
Illinois	$193 - $439	$50	$243	$32
New Jersey	116 - 203	6	122	13
Georgia and Florida	53 - 106	12	68	4
North Carolina	n/a	11	11	8
Total	$362 - $748	$79	$444	$57

We have identified 26 former operating sites in Illinois where Nicor Gas or its predecessors owned or operated all or part of the sites. With the exception of ten sites, material cleanups have not been completed, nor are precise estimates available for future cleanup costs and, therefore, considerable variability remains in future cost estimates. Nicor Gas and Commonwealth Edison Company are parties to an agreement to cooperate in cleaning up residue at many of these sites. The agreement allocates to Nicor Gas 51.7% of cleanup costs for 23 of the sites. In addition to the sites from the agreement, there are 3 sites for which we have sole responsibility.

We have confirmed 13 former operating sites in Georgia and Florida where Atlanta Gas Light or its predecessors owned or operated all or part of the sites. As of December 31, 2012, the soil and sediment remediation program was substantially complete for all but one of the Georgia sites, although groundwater cleanup or monitoring continues. Investigation is concluded for one phase of the Orlando, Florida site; however, the Environmental Protection Agency has not approved the cleanup plans. For elements of the Georgia and Florida sites where we still cannot provide engineering cost estimates, considerable variability remains in future cost estimates.

We have identified 6 former operating sites in New Jersey where Elizabethtown Gas owned or operated all or part of the sites. With the exception of two sites, material cleanups have not been completed, nor are precise estimates available for future cleanup costs and, therefore, considerable variability remains in future cost estimates. We have also identified a site in North Carolina that is subject to a remediation order by the North Carolina Department of Energy and Natural Resources, and there are no cost recovery mechanisms for the environmental remediation of this site.

Our ERC liabilities are estimates of future remediation costs for our former operating sites that are contaminated. Our estimates are based on conventional engineering estimates and the use of probabilistic models of potential costs when such estimates cannot be made, which is generally the case when remediation has not commenced or during the early years of a remediation effort. For those elements of the program where we cannot perform engineering estimates, there remains considerable variability in future cost estimates. Accordingly, we have established a probabilistic model to determine a range of potential expenditures to remediate and monitor our former operating sites. We cannot, at this time, identify any single number within this range as a better estimate of likely future costs, and we generally have recorded the low end of the range for our probabilistic cost estimates.

As we 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 assumptions, which we refine and update on an ongoing basis. In 2012, we completed our probabilistic models and engineering estimates for our sites in Illinois, which primarily contributed to the $117 million increase from the amount recorded at December 31, 2011. These costs are recoverable from our customers as they are paid and, accordingly, we have recorded a regulatory asset associated with the recorded liabilities.

With the exception of our North Carolina site, 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 and expect to collect $38 million in revenues over the next 12 months, which is reflected as a current asset. We recovered $13 million in 2012, $5 million in 2011 and $10 million in 2010 from our ERC rate riders.

Litigation

We are involved in litigation arising in the normal course of business. Although in some cases we are unable to estimate the amount of loss reasonably possible in addition to any amounts already recognized, it is possible that the resolution of these contingencies, either individually or in aggregate, will require us to take charges against, or will result in reductions in, future earnings. It is the opinion of management that the resolution of these contingencies, either individually or in aggregate, could be material to earnings in a particular period but will not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

PBR Proceeding Nicor Gas' PBR plan for natural gas costs went into effect in 2000 and was terminated effective January 1, 2003. Under this plan, Nicor Gas' total gas supply costs were compared to a market-sensitive benchmark. Savings and losses relative to the benchmark were determined annually and shared equally with sales customers. The PBR plan is currently under review by the Illinois Commission as there are allegations that Nicor Gas acted improperly in connection with the plan. On June 27, 2002, the Citizens Utility Board (CUB) filed a motion to reopen the record in the Illinois Commission's proceedings to review the PBR plan (the "Illinois Commission Proceedings"). As a result of the motion to reopen, Nicor Gas entered into a stipulation with the staff of the Illinois Commission and CUB providing for additional discovery. The Illinois Attorney General's Office (IAGO) has also intervened in this matter. In addition, the IAGO issued Civil Investigation Demands (CIDs) to CUB and the Illinois Commission staff. The CIDs ordered that CUB and the Illinois Commission staff produce all documents relating to any claims that Nicor Gas may have presented, or caused to be presented, regarding false information related to its PBR plan. We have committed to cooperate fully in the reviews of the PBR plan.

The Nicor Board of Directors directed management to, among other things, make appropriate adjustments to account for, and fully address, the adverse consequences to ratepayers, and conduct a detailed study of the adequacy of internal accounting and regulatory controls. The adjustments were made in prior years' financial statements resulting in a $25 million liability. Included in this $25 million liability is a $4 million loss contingency. A $2 million adjustment to the previously recorded liability, which is discussed below, was made in 2004 increasing the recorded liability to $27 million. By the end of 2003, Nicor Gas completed steps to correct the weaknesses and deficiencies identified in the detailed study of the adequacy of internal controls.

On February 5, 2003, CUB filed a motion for $27 million in sanctions against Nicor Gas in the Illinois Commission Proceedings. In that motion, CUB alleged that Nicor Gas' responses to certain CUB data requests were false. Also on February 5, 2003, CUB stated in a press release that, in addition to $27 million in sanctions, it would seek additional refunds to consumers. On March 5, 2003, the Illinois Commission staff filed a response brief in support of CUB's motion for sanctions. On May 1, 2003, the Administrative Law Judges assigned to the proceeding issued a ruling denying CUB's motion for sanctions. CUB has filed an appeal of the motion for sanctions with the Illinois Commission, and the Illinois Commission has indicated that it will not rule on the appeal until the final disposition of the Illinois Commission Proceedings. It is not possible to determine how the Illinois Commission will resolve the claims of CUB or other parties to the Illinois Commission Proceedings.

In 2004, Nicor Gas became aware of additional information relating to the activities of individuals affecting the PBR plan for the period from 1999 through 2002, including information consisting of third party documents and recordings of telephone conversations from Entergy-Koch Trading, LP (EKT), a natural gas, storage and transportation trader and consultant with whom Nicor Gas did business under the PBR plan. Review of additional information completed in 2004 resulted in the $2 million adjustment to the previously recorded liability referenced above.

The evidentiary hearings on this matter were stayed in 2004 in order to permit the parties to undertake additional third party discovery from EKT. In December 2006, the additional third party discovery from EKT was obtained and the Administrative Law Judge issued a scheduling order that provided for Nicor Gas to submit direct testimony by April 13, 2007. Nicor Gas submitted direct testimony in April 2007, rebuttal testimony in April 2011 and surrebuttal testimony in December 2011. In surrebuttal testimony, we sought $6 million, which included interest due to us of $2 million, as of December 31, 2011. The staff of the Illinois Commission, IAGO and CUB submitted direct testimony to the Illinois Commission in April 2009 and rebuttal testimony in October 2011. In rebuttal testimony, the staff of the Illinois Commission, IAGO and CUB requested refunds of $85 million, $255 million and $305 million, respectively.

In February 2012, we committed to a stipulated resolution of issues with the staff of the Illinois Commission, which would include crediting Nicor Gas customers $64 million. This resulted in a $37 million adjustment to the previously recorded $27 million liability referenced above and is reflected in the purchase price allocation. The stipulated resolution does not constitute an admission of fault, and it is not final and is subject to review and approval by the Illinois Commission. The CUB and IAGO are not parties to the stipulated resolution and continue to pursue their claims in this proceeding. Evidentiary hearings before the Administrative Law Judges were held during the first quarter of 2012 and post-trial legal briefs from the parties were submitted during the second quarter of 2012. Following the submission of legal briefs, on November 5, 2012, the Administrative Law Judges issued a proposed order for a refund of $72 million to ratepayers. We have increased our accrual by $8 million for a total of $72 million as a result of these developments and its effect on the estimated liability. We do not agree with the additional $8 million proposed by the Administrative Law Judges and will consider all legal recourse available should the Illinois Commission authorize a refund greater than the $64 million stipulation amount between Nicor Gas and the staff of the Illinois Commission.

Nicor Services Warranty Product Actions In the first quarter of 2011, three putative class actions were filed against Nicor Services and Nicor Gas, and in one case against Nicor. In September 2011, the three cases were consolidated into a single class action pending in state court in Cook County, Illinois. The plaintiffs purport to represent a class of customers of Nicor Gas who purchased appliance warranty and service plans from Nicor Services and/or a class of customers of Nicor Gas who purchased the Gas Line Comfort Guard product from Nicor Services. In the consolidated action, the plaintiffs variously allege that the marketing, sale and billing of the Nicor Services appliance warranty and service plans and Gas Line Comfort Guard violate the Illinois Consumer Fraud and Deceptive Business Practices Act, constitute common law fraud and result in unjust enrichment of Nicor Services and Nicor Gas. The plaintiffs seek, on behalf of the classes they purport to represent, actual and punitive damages, interest, costs, attorney fees and injunctive relief. While we are unable to predict the outcome of these matters or to reasonably estimate our potential exposure related thereto, if any, and have not recorded a liability associated with this contingency, the final disposition of this matter is not expected to have a material adverse impact on our liquidity or financial condition.

Municipal Tax Matters Many municipalities in Nicor Gas' service territory have enacted ordinances that impose taxes on gas sales to customers within municipal boundaries. Most of these municipal taxes are imposed on Nicor Gas based on revenues generated by Nicor Gas within the municipality. Other municipal taxes are imposed on natural gas consumers within the municipality but are collected from consumers and remitted to the municipality by us. In May 2007, five of those municipalities filed an action against Nicor Gas in state court in DuPage County, Illinois relating to these taxes. Pursuant to the terms of settlement between Nicor Gas and the five municipalities, the lawsuit was dismissed without prejudice in 2012.

Other In addition to the matters set forth above, we are involved with legal or administrative proceedings before various courts and agencies with respect to general claims, taxes, environmental, gas cost prudence reviews and other matters. Although we are unable to determine the ultimate outcome of these other contingencies, we believe that these amounts are appropriately reflected in our financial statements, including the recording of appropriate liabilities when reasonably estimable.

Note 12 - Income Taxes

Income Tax Expense

The relative split between current and deferred taxes is due to a variety of factors including true ups of prior year tax returns, and most importantly, the timing of our property-related deductions. Components of income tax expense shown in the Consolidated Statements of Income are shown in the following table.

In millions	**2012**	**2011**	**2010**
Current income taxes			
Federal	$9	$(89)	$37
State	4	1	12
Deferred income taxes			
Federal	134	196	86
State	20	18	6
Amortization of investment tax credits	(3)	(1)	(1)
Total	$164	$125	$140

The reconciliations between the statutory federal income tax rate, the effective rate and the related amount of tax for the years ended December 31, 2012, 2011 and 2010 on our Consolidated Statements of Income are presented in the following table.

In millions	**2012**	**2011**	**2010**
Computed tax expense at statutory rate	$158	$109	$136
State income tax, net of federal income tax benefit	19	14	15
Tax effect of net income attributable to the noncontrolling interest	(6)	(6)	(6)
Amortization of investment tax credits	(3)	(1)	(1)
Affordable housing credits	(2)	(1)	(2)
Flexible dividend deduction	(2)	(2)	(2)
Change in control payments	0	9	0
Merger transaction costs	0	3	0
Total income tax expense on Consolidated Statements of Income	$164	$125	$140

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 rate-regulated entities, which we are amortizing over approximately 30 years (see Note 2). Our deferred tax assets include $145 million related to an unfunded pension and other retirement benefit obligation, an increase of $8 million from 2011.

We have provided a valuation allowance for some of these items that reduce our net deferred tax assets to amounts we believe are more likely than not to be realized in future periods. With respect to our continuing operations, we have net operating losses in various jurisdictions. Components that give rise to the net accumulated deferred income tax liability are as follows.

In millions	As of December 31, 2012	2011
Accumulated deferred income tax liabilities		
Property - accelerated depreciation and other property-related items	$1,533	$1,418
Mark to market	22	22
Investments in partnerships	26	42
Other	126	91
Acquisition intangibles	26	34
Undistributed earnings of foreign subsidiaries	30	39
Total accumulated deferred income tax liabilities	1,763	1,646
Accumulated deferred income tax assets		
Deferred investment tax credits	9	10
Unfunded pension and other retirement benefit obligation	145	137
Other	43	57
Total accumulated deferred income tax assets	197	204
Valuation allowances (1)	(22)	(3)
Total accumulated deferred income tax assets, net of valuation allowance	175	201
Net accumulated deferred tax liability	$1,588	$1,445

(1) $3 million valuation allowance is due to the net operating losses on a former non-operating subsidiary that are not allowed in New Jersey and $19 million valuation allowance is related to our investment in Triton.

To the extent foreign cargo shipping earnings are not repatriated to the United States, such earnings are not currently subject to taxation. In addition, to the extent such earnings are indefinitely reinvested offshore, no deferred income tax expense is recorded by us. At December 31, 2012, we had $30 million of deferred income tax liabilities related to $87 million of cumulative undistributed earnings of our foreign subsidiaries. We have not recorded deferred income taxes of $31 million on $89 million of cumulative undistributed foreign earnings. At December 31, 2011, we had $39 million of deferred income tax liabilities related to $104 million of cumulative undistributed earnings of our foreign subsidiaries.

Tax Benefits

As of December 31, 2012 and December 31, 2011, we did not have a liability for unrecognized tax benefits. Based on current information, we do not anticipate that this will change materially in 2013. As of December 31, 2012, we did not have a liability recorded for payment of interest or penalties associated with uncertain tax positions.

We file a United States federal consolidated income tax return and various state income tax returns. We are no longer subject to income tax examinations by the Internal Revenue Service or in any state for years before 2007.

Note 13 - Segment Information

Our operating segments comprise revenue-generating components of our company for which we produce separate financial information internally that we regularly use to make operating decisions and assess performance. Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. We manage our businesses through five operating segments - distribution operations, retail operations, wholesale services, midstream operations, cargo shipping and one non-operating segment, other.

Our distribution operations segment is the largest component of our business and includes natural gas local distribution utilities in seven states - Illinois, Georgia, Virginia, New Jersey, Florida, Tennessee and Maryland. These utilities construct, manage, and maintain intrastate natural gas pipelines and distribution facilities. Although the operations of our distribution operations segment are geographically dispersed, the operating subsidiaries within the distribution operations segment are regulated utilities, with rates determined by individual state regulatory commissions. These natural gas distribution utilities have similar economic and risk characteristics.

We are also involved in several related and complementary businesses. Our retail operations segment includes retail natural gas marketing to end-use customers primarily in Georgia as well as various businesses that market retail energy-related products and services to residential and small business customers in Illinois. Additionally, our retail operations segment provides warranty protection solutions to customers and customer move connection services for utilities. Our wholesale services segment engages in natural gas storage and gas pipeline arbitrage and related activities. Additionally, they provide natural gas asset management and/or related logistics services for each of our utilities, as well as for non-affiliated companies, natural gas storage arbitrage and related activities. Our midstream operations segment includes our non-utility storage and pipeline operations, including the development and operation of high-deliverability natural gas storage assets.

Our cargo shipping segment transports containerized freight between Florida, the eastern coast of Canada, the Bahamas and the Caribbean region. Our cargo shipping segment also includes amounts related to cargo insurance coverage sold to our customers and other third parties. Our cargo shipping segment's vessels are under foreign registry, and its containers are considered instruments of international trade. Although the majority of its long-lived assets are foreign owned and its revenues are derived from foreign operations, the functional currency is generally the United States dollar. Our cargo shipping segment also includes an equity investment in Triton, a cargo container leasing business. Profits and losses are generally allocated to investors' capital accounts in proportion to their capital contributions. Our investment in Triton is accounted for under the equity method, and our share of earnings is reported within "Other Income" on our Consolidated Statements of Income.

Our other segment includes intercompany eliminations and aggregated subsidiaries that are not significant enough on a stand-alone basis and that do not fit into one of our other five operating segments.

We evaluate segment performance using the non-GAAP measure of EBIT, that includes operating income, other income and expenses, and equity investment income. Items we do not include in EBIT are income taxes and financing costs, including interest and debt expense, each of which we evaluate on a consolidated basis. We believe EBIT is a useful measurement of our performance because it provides information that can be used to evaluate the effectiveness of our businesses from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which is directly relevant to the efficiency of those operations.

You should not consider EBIT an alternative to, or a more meaningful indicator of, our operating performance than operating income or net income as determined in accordance with GAAP. In addition, our EBIT may not be comparable to a similarly titled measure of another company. The reconciliations of EBIT to operating income, earnings before income taxes and net income for 2012, 2011 and 2010 are presented below.

In millions	**2012**	**2011**	**2010**
Operating income	$610	$440	$500
Other income (expense)	24	7	(1)
EBIT	634	447	499
Interest expense	184	136	109
Earnings before income taxes	450	311	390
Income taxes	164	125	140
Net income	$286	$186	$250

Summarized Statements of Income, Statements of Financial Position and capital expenditure information by segment as of and for the years ended December 31, 2012, 2011 and 2010 are shown in the following tables.

Please note that our segments have changed as a result of our merger with Nicor and amounts from the periods presented have been reclassified between the segments to reflect these changes.

2012

In millions	**Distribution operations**	**Retail operations**	**Wholesale services**	**Midstream operations**	**Cargo shipping**	**Other and intercompany eliminations** (4)	**Consolidated**
Operating revenues from external parties	$2,710	$733	$58	$78	$342	$1	$3,922
Intercompany revenues (1)	167	2	30	0	0	(199)	0
Total operating revenues	2,877	735	88	78	342	(198)	3,922
Operating expenses							
Cost of goods sold	1,221	488	38	32	208	(196)	1,791
Operation and maintenance	642	114	48	19	109	(11)	921
Depreciation and amortization	351	13	2	14	22	13	415
Nicor merger expenses (2)	0	0	0	0	0	20	20
Taxes other than income taxes	140	4	4	5	6	6	165
Total operating expenses	2,354	619	92	70	345	(168)	3,312
Operating income (loss)	523	116	(4)	8	(3)	(30)	610
Other income	9	0	1	2	11	1	24
EBIT	$532	$116	$(3)	$10	$8	$(29)	$634
Identifiable and total assets (3)	$11,320	$511	$1,218	$720	$464	$(92)	$14,141
Goodwill	$1,640	$122	$0	$14	$61	$0	$1,837
Capital expenditures	$649	$8	$3	$62	$7	$53	$782

2011

In millions	**Distribution operations**	**Retail operations**	**Wholesale services**	**Midstream operations**	**Cargo shipping**	**Other and intercompany eliminations** (4)	**Consolidated**
Operating revenues from external parties	$1,451	$702	$95	$70	$19	$1	$2,338
Intercompany revenues (1)	146	0	3	0	0	(149)	0
Total operating revenues	1,597	702	98	70	19	(148)	2,338
Operating expenses							
Cost of goods sold	625	534	41	33	12	(148)	1,097
Operation and maintenance	362	71	48	15	7	(2)	501
Depreciation and amortization	160	2	1	10	1	12	186
Nicor merger expenses (2)	0	0	0	0	0	57	57
Taxes other than income taxes	44	2	3	3	0	5	57
Total operating expenses	1,191	609	93	61	20	(76)	1,898
Operating income (loss)	406	93	5	9	(1)	(72)	440
Other income	6	0	0	0	1	0	7
EBIT	$412	$93	$5	$9	$0	$(72)	$447
Identifiable and total assets (3)	$11,020	$501	$1,214	$635	$481	$62	$13,913
Goodwill	$1,586	$124	$2	$16	$77	$8	$1,813
Capital expenditures	$365	$2	$1	$35	$0	$24	$427

2010

In millions	Distribution operations	Retail operations	Wholesale services	Midstream operations	Cargo shipping	Other and intercompany eliminations (4)	Consolidated
Operating revenues from external parties	$1,349	$840	$121	$46	$0	$17	$2,373
Intercompany revenues (1)	145	0	0	0	0	(145)	0
Total operating revenues	1,494	840	121	46	0	(128)	2,373
Operating expenses							
Cost of goods sold	615	657	16	16	0	(140)	1,164
Operation and maintenance	358	76	52	17	0	(6)	497
Depreciation and amortization	138	2	2	5	0	13	160
Nicor merger expenses (2)	0	0	0	0	0	6	6
Taxes other than income taxes	35	2	3	2	0	4	46
Total operating expenses	1,146	737	73	40	0	(123)	1,873
Operating income (loss)	348	103	48	6	0	(5)	500
Other income (expense)	4	0	1	0	0	(6)	(1)
EBIT	$352	$103	$49	$6	$0	$(11)	$499
Identifiable and total assets (3)	$5,484	$259	$1,326	$471	$0	$(20)	$7,520
Goodwill	$404	$0	$0	$14	$0	$0	$418
Capital expenditures	$357	$3	$2	$126	$0	$22	$510

(1) Intercompany revenues - wholesale services records its energy marketing and risk management revenues on a net basis and its total operating revenues include intercompany revenues of $350 million in 2012, $449 million in 2011 and $473 million in 2010.
(2) Transaction expenses associated with the Nicor merger are shown separately to better compare year-over-year results.
(3) Identifiable assets are those used in each segment's operations.
(4) Our other segment's assets consist primarily of cash and cash equivalents, property, plant and equipment and the effect of intercompany eliminations.

Note 14 - Selected Quarterly Financial Data (Unaudited)

Our quarterly financial data for 2012, 2011 and 2010 are summarized below. The variance in our quarterly earnings is the result of the seasonal nature of our primary business.

In millions, except per share amounts	March 31	June 30	September 30	December 31
2012				
Operating revenues	$1,404	$686	$614	$1,218
Operating income	262	91	54	203
Net income attributable to AGL Resources Inc.	130	34	9	98
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	1.12	0.28	0.08	0.84
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	1.11	0.28	0.08	0.84
2011				
Operating revenues	$878	$375	$295	$790
Operating income	238	60	24	118
Net income (loss) attributable to AGL Resources Inc.	124	18	(3)	33
Basic earnings (loss) per common share attributable to AGL Resources Inc. common shareholders	1.60	0.23	(0.04)	0.37
Diluted earnings (loss) per common share attributable to AGL Resources Inc. common shareholders	1.59	0.23	(0.04)	0.37
2010				
Operating revenues	$1,003	$359	$346	$665
Operating income	253	48	62	137
Net income attributable to AGL Resources Inc.	134	14	22	64
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	1.74	0.17	0.29	0.82
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	1.73	0.17	0.29	0.81

Our basic and diluted earnings per common share are calculated based on the weighted daily average number of common shares and common share equivalents outstanding during the quarter. Those totals differ from the basic and diluted earnings per common share attributable to AGL Resources Inc. common shareholders shown in the Consolidated Statements of Income, which are based on the weighted average number of common shares and common share equivalents outstanding during the entire year.

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

None

ITEM 9A. CONTROLS AND PROCEDURES

Conclusions Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act). No system of controls, no matter how well-designed and operated, can provide absolute assurance that the objectives of the system of controls are met, and no evaluation of controls can provide assurance that the system of controls has operated effectively in all cases. Our disclosure controls and procedures however are designed to provide reasonable assurance that the objectives of disclosure controls and procedures are met.

Based on this evaluation, our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2012, in providing a reasonable level of assurance that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods in SEC rules and forms, including a reasonable level of assurance that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our principal executive officer and our principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the fourth quarter ended December 31, 2012, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Reports of Management and Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting

Management has assessed, and our independent registered public accounting firm, PricewaterhouseCoopers LLP, has audited, our internal control over financial reporting as of December 31, 2012. The unqualified reports of management and PricewaterhouseCoopers LLP thereon are included in Item 8 of this Annual Report on Form 10-K and are incorporated by reference herein.

ITEM 9B. OTHER INFORMATION

None

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

EXECUTIVE OFFICERS OF THE REGISTRANT

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

Name, age and position with the company	Periods served
John W. Somerhalder II, Age 57	
Chairman, President and Chief Executive Officer	October 2007 - Present
President and Chief Executive Officer	March 2006 - October 2007
Andrew W. Evans, Age 46	
Executive Vice President and Chief Financial Officer	November 2010 - Present
Executive Vice President, Chief Financial Officer and Treasurer	June 2009 - November 2010
Executive Vice President and Chief Financial Officer	May 2006 - June 2009
Henry P. Linginfelter, Age 52	
Executive Vice President, Distribution Operations	December 2011 - Present
Executive Vice President, Utility Operations	June 2007 - December 2011
Senior Vice President, Mid-Atlantic Operations	November 2004 - June 2007
Melanie M. Platt, Age 58	
Executive Vice President, Chief People Officer and President, AGL Resources Foundation	December 2011 - Present
Senior Vice President, Human Resources and Marketing Communications	November 2008 - December 2011
Senior Vice President, Human Resources	September 2004 - November 2008
Paul R. Shlanta, Age 55	
Executive Vice President, General Counsel and Chief Ethics and Compliance Officer	September 2005 - Present
Peter I. Tumminello, Age 50	
Executive Vice President, Wholesale Services, and President Sequent	December 2011 - Present
President, Sequent	April 2010 - December 2011
Executive Vice President, Business Development and Support, Sequent	February 2007 - April 2010
Vice President, Corporate Business Development	November 2005 - February 2007

The other information required by this item with respect to directors will be set forth under the captions “Proposal I - Election of Directors,” - “Corporate Governance - Ethics and Compliance Program,” - “Committees of the Board” and “- Audit Committee” in the Proxy Statement for our 2013 Annual Meeting of Shareholders or in a subsequent amendment to this report. The information required by this item with respect to Section 16(a) beneficial ownership reporting compliance will be set forth under the caption “Section 16(a) Beneficial Ownership Reporting Compliance” in the Proxy Statement or subsequent amendment referred to above. All such information that is provided in the Proxy Statement is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item will be set forth under the captions “Compensation and Management Development Committee Report,” “Compensation and Management Development Committee Interlocks and Insider Participation,” “Director Compensation,” “Compensation Discussion and Analysis” and “Executive Compensation” in the Proxy Statement or subsequent amendment referred to in Item 10 above. All such information that is provided in the Proxy Statement is incorporated herein by reference, except for the information under the caption “Compensation and Management Development Committee Report” which is specifically not so incorporated herein by reference.

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

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

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

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

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this item will be set forth under the caption "Proposal 2 - Ratification of the Appointment of PricewaterhouseCoopers LLP as Our Independent Registered Public Accounting Firm for 2013" in the Proxy Statement or subsequent amendment to referred to in Item 10 above. All such information that is provided in the Proxy Statement is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) Documents Filed as Part of This Report.

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

- Report of Independent Registered Public Accounting Firm
- Management's Report on Internal Control Over Financial Reporting
- Consolidated Statements of Financial Position as of December 31, 2012 and 2011
- Consolidated Statements of Income for the years ended December 31, 2012, 2011 and 2010
- Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2012, 2011 and 2010
- Consolidated Statements of Equity for the years ended December 31, 2012, 2011 and 2010
- Consolidated Statements of Cash Flows for the years ended December 31, 2012, 2011 and 2010
- Notes to Consolidated Financial Statements

(2) Financial Statement Schedules

Financial Statement Schedule II. Valuation and Qualifying Accounts - Allowance for Uncollectible Accounts and Income Tax Valuations for Each of the Three Years in the Period Ended December 31, 2012.

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

(3) Exhibits

Where an exhibit is filed by incorporation by reference to a previously filed registration statement or report, such registration statement or report is identified in parentheses. The Commission file number reference for any exhibit incorporated by reference is 001-14174, unless otherwise indicated.

2.1	Agreement and Plan of Merger, as amended, among AGL Resources Inc., Apollo Acquisition Corp., Ottawa Acquisition LLC and Nicor Inc., dated December 6, 2010 (Exhibit 2.1, AGL Resources Inc. Form 8-K filed December 7, 2010).
2.2	Waiver entered into as of February 4, 2011, by and among AGL Resources Inc., Apollo Acquisition Corp. and Nicor Inc. (Exhibit 2.1, AGL Resources Inc. Form 8-K filed February 9, 2011).
3.1	Amended and Restated Articles of Incorporation of AGL Resources Inc., filed December 9, 2011, with the Secretary of State of the state of Georgia (Exhibit 3.1, AGL Resources Inc. Form 8-K filed December 13, 2011).
3.2	Bylaws of AGL Resources Inc., as amended on July 31, 2012 (Exhibit 3.1, AGL Resources Inc. Form 8-K filed August 6, 2012).
4.1	Specimen form of Common Stock certificate (Exhibit 4.1, AGL Resources Inc. Form 10-Q for the fiscal quarter ended September 30, 2007).
4.2.a	Specimen AGL Capital Corporation 6.00% Senior Notes due 2034 (Exhibit 4.1, AGL Resources Inc. Form 8-K filed September 27, 2004).
4.2.b	Form of Guarantee of AGL Resources Inc. dated as of September 27, 2004 regarding the AGL Capital Corporation 6.00% Senior Notes due 2034 (Exhibit 4.3, AGL Resources Inc. Form 8-K filed September 27, 2004).
4.3.a	Specimen AGL Capital Corporation 4.95% Senior Notes due 2015 (Exhibit 4.1, AGL Resources Inc. Form 8-K filed December 21, 2004).
4.3.b	Form of Guarantee of AGL Resources Inc. dated as of December 20, 2004 regarding the AGL Capital Corporation 4.95% Senior Notes due 2015 (Exhibit 4.3, AGL Resources Inc. Form 8-K filed December 21, 2004).

4.4.a	Form of AGL Capital Corporation 6.375% Senior Notes due 2016 (Exhibit 4.1, AGL Resources Inc. Form 8-K filed December 14, 2007).
4.4.b	Form of Guarantee of AGL Resources Inc. dated as of December 14, 2007 regarding the AGL Capital Corporation 6.375% Senior Notes due 2016 (Exhibit 4.2, AGL Resources Inc. Form 8-K filed December 14, 2007).
4.5.a	Specimen AGL Capital Corporation 4.45% Senior Notes due 2013 (Exhibit 4.1.g, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2007).
4.5.b	Form of Guarantee of AGL Resources Inc. dated as of July 2, 2003 regarding the AGL Capital Corporation 4.45% Senior Notes due 2013 (Exhibit 4.3.e, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2007).
4.6.a	Specimen AGL Capital Corporation 5.25% Senior Notes due 2019 (Exhibit 4.1, AGL Resources Inc. Form 8-K filed August 10, 2009).
4.6.b	Form of Guarantee of AGL Resources Inc. dated as of August 10, 2009 regarding the AGL Capital Corporation 5.25% Senior Notes due 2019 (Exhibit 4.2, AGL Resources Inc. Form 8-K filed August 2009).
4.7.a.	Form of AGL Capital Corporation 5.875% Senior Notes due 2041 (Exhibit 4.1, AGL Resources Inc. Form 8-K filed March 21, 2011).
4.7.b	Form of Guarantee of AGL Resources Inc. dated as of March 21, 2011 regarding the AGL Capital Corporation 5.875% Senior Notes due 2041 (Exhibit 4.2, AGL Resources Inc. Form 8-K filed March 21, 2011).
4.8.a	Form of AGL Capital Corporation 3.500% Senior Notes due 2021 (Exhibit 4.1, AGL Resources Inc. Form 8-K filed September 20, 2011).
4.8.b	Form of Guarantee of AGL Resources Inc. dated as of September 2011 regarding the AGL Capital Corporation 3.500% Senior Notes due 2021 (Exhibit 4.2, AGL Resources Inc. Form 8-K filed September 20, 2011).
4.9.a	Form of AGL Capital Corporation Series A Senior Notes due 2016 (Exhibit 4.1, AGL Resources Inc. Form 8-K filed September 7, 2011).
4.9.b	Form of AGL Capital Corporation Series B Senior Notes due 2018 (Exhibit 4.2, AGL Resources Inc. Form 8-K filed September 7, 2011).
4.10.a	Indenture, dated as of December 1, 1989, between Atlanta Gas Light Company and Bankers Trust Company, as Trustee (Exhibit 4(a), Atlanta Gas Light Company registration statement on Form S-3, File No. 33-32274).
4.10.b	First Supplemental Indenture dated as of March 16, 1992, between Atlanta Gas Light Company and NationsBank of Georgia, National Association, as Successor Trustee (Exhibit 4(a), Atlanta Gas Light Company registration statement on Form S-3, File No. 33-46419).
4.11	Indenture, dated February 20, 2001 among AGL Capital Corporation, AGL Resources Inc. and The Bank of New York, as Trustee (Exhibit 4.2, AGL Resources Inc. registration statement on Form S-3, filed on September 17, 2001, File No. 333-69500).
4.12.a	Indenture of Commonwealth Edison Company to Continental Illinois National Bank and Trust Company of Chicago, Trustee, dated as of January 1, 1954 (Exhibit 4.01, Northern Illinois Gas Company Form 10-K for the fiscal year ended December 31, 1995, File No. 1-7296).
4.12.b	Indenture of Adoption of Northern Illinois Gas Company to Continental Illinois National Bank and Trust Company of Chicago, Trustee, dated February 9, 1954 (Exhibit 4.02, Northern Illinois Gas Company Form 10-K for the fiscal year ended December 31, 1995, File No. 1-7296).
4.12.c	Supplemental Indenture, dated February 15, 1998, of Northern Illinois Gas Company to Harris Trust and Savings Bank, Trustee, under Indenture dated as of January 1, 1954 (Exhibit 4.19, Northern Illinois Gas Company Form 10-K for the fiscal year ended December 31, 1997, File No. 1-7296).
4.12.d	Supplemental Indenture, dated May 15, 2001, of Northern Illinois Gas Company to BNY Midwest Trust Company, Trustee, under Indenture dated as of January 1, 1954 (Exhibit 4.18, Northern Illinois Gas Company registration statement on Form S-3 filed July 20, 2001, File No. 333-65486).
4.12.e	Supplemental Indenture, dated December 1, 2003, of Northern Illinois Gas Company to BNY Midwest Trust Company, Trustee, under Indenture dated as of January 1, 1954 (Exhibit 4.09, Northern Illinois Gas Company Form 10-K for the fiscal year ended December 31, 2003, File No. 1-7296).
4.12.f	Supplemental Indenture, dated December 1, 2003, of Northern Illinois Gas Company to BNY Midwest Trust Company, Trustee, under Indenture dated as of January 1, 1954 (Exhibit 4.10, Northern Illinois Gas Company Form 10-K for the fiscal year ended December 31, 2003, File No. 1-7296).
4.12.g	Supplemental Indenture, dated December 1, 2003, of Northern Illinois Gas Company to BNY Midwest Trust Company, Trustee, under Indenture dated as of January 1, 1954 (Exhibit 4.11, Northern Illinois Gas Company Form 10-K for the fiscal year ended December 31, 2003, File No. 1-7296).

4.12.h Supplemental Indenture, dated December 1, 2006, of Northern Illinois Gas Company to BNY Midwest Trust Company, Trustee, under Indenture dated as of January 1, 1954 (Exhibit 4.11, Northern Illinois Gas Company Form 10-K for the fiscal year ended December 31, 2006, File No. 1-7296).

4.12.i Supplemental Indenture, dated August 1, 2008, of Northern Illinois Gas Company to BNY Mellon Trust Company, Trustee, under Indenture dated January 1, 1954 (Exhibit 4.01, Northern Illinois Gas Company Form 10-Q for the fiscal quarter ended September 30, 2008, File No. 1-7296).

4.12.j Supplemental Indenture, dated July 23, 2009, of Northern Illinois Gas Company to BNY Mellon Trust Company, Trustee, under Indenture dated as of January 1, 1954 (Exhibit 4.01, Northern Illinois Gas Company Form 10-Q for the fiscal quarter ended June 30, 2009, File No. 1-7296).

4.12.k Supplemental Indenture, dated February 1, 2011, of Northern Illinois Gas Company to BNY Mellon Trust Company, Trustee, under Indenture dated as of January 1, 1954 (Exhibit 4.12, Northern Illinois Gas Company Form 10-K for the fiscal year ended December 31, 2010, File No. 1-7296).

4.12.l Supplemental Indenture, dated October 26, 2012, of Northern Illinois Gas Company to BNY Mellon Trust Company, N.A., Trustee, under the Indenture dated as of January 1, 1954 (Exhibit 4, Northern Illinois Gas Company Form 10-Q for the fiscal quarter ended September 30, 2012, File No. 1-7296).

Director Compensation Contracts, Plans and Arrangements

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

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

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

10.1.d AGL Resources Inc. 2006 Non-Employee Directors Equity Compensation Plan, amended and restated as of December 9, 2011 (Exhibit 10.2, AGL Resources Inc. Form 8-K dated December 15, 2011).

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

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

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

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

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

10.1.j Fifth Amendment to the AGL Resources Inc. 1998 Common Stock Equivalent Plan for Non-Employee Directors. (Exhibit 10.1.l, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2008).

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

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

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

Executive Compensation Contracts, Plans and Arrangements

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

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

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

10.1.ad Third amendment to the AGL Resources Inc. Long-Term Incentive Plan (1999), as amended and restated. (Exhibit 10.1.ad, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2008).

10.1.ae AGL Resources Omnibus Performance Incentive Plan, as Amended and Restated (Annex A of AGL Resources Inc.'s Schedule 14A, File No. 001-14174, filed with the Securities and Exchange Commission on March 14, 2011).

10.1.af	Form of Restricted Stock Unit (RSU) Agreement under Omnibus Performance Incentive Plan, as Amended and Restated (Exhibit 10.1.ae, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2011).
10.1.ag	Form of Restricted Stock Agreement under Omnibus Performance Incentive Plan, as Amended and Restated (Exhibit 10.1.af, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2011).
10.1.ah	Form of Performance Share Unit Award under Omnibus Performance Incentive Plan, as Amended and Restated.
10.1.ai	AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Annex A of AGL Resources Inc.'s Schedule 14A, File No. 001-14174, filed with the Securities and Exchange Commission on March 19, 2007).
10.1.aj	First Amendment to the AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.ai, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2008).
10.1.ak	Form of Incentive Stock Option Agreement - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.b, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).
10.1.al	Form of Nonqualified Stock Option Agreement - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.c, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).
10.1.am	Form of Performance Cash Award Agreement - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.al, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2009).
10.1.an	Form of Restricted Stock Agreement (performance based) - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.e, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).
10.1.ao	Form of Restricted Stock Agreement (time based) - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.f, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).
10.1.ap	Form of Restricted Stock Unit Agreement - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.ao, AGL Resources Form 10-K for the fiscal year ended December 31, 2009).
10.1.aq	Form of Stock Appreciation Rights Agreement - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.h, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).
10.1.ar	Form of Incentive Stock Option Agreement, Nonqualified Stock Option Agreement and Restricted Stock Agreement for key employees (Exhibit 10.1, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2004).
10.1.as	Form of Performance Unit Agreement for key employees (Exhibit 10.1.e, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2004).
10.1.at	Forms of Nonqualified Stock Option Agreement without the reload provision (LTIP and Officer Incentive Plan) (Exhibit 10.1, AGL Resources Inc. Form 8-K filed March 18, 2005).
10.1.au	Form of Nonqualified Stock Option Agreement with the reload provision (Officer Incentive Plan) (Exhibit 10.2, AGL Resources Inc. Form 8-K filed March 18, 2005).
10.1.av	Form of Restricted Stock Unit Agreement and Performance Cash Unit Agreement for key employees (Exhibit 10.2 and 10.3, respectively, AGL Resources Inc. Form 8-K filed February 24, 2006).
10.1.aw	AGL Resources Inc. Nonqualified Savings Plan as amended and restated as of January 1, 2009. (Exhibit 10.1.av, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2008).
10.1.ax	Form of AGL Resources Inc. Annual Incentive Plan (Exhibit 10.1.av, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2011).
10.1.ay	Description of Supplemental Executive Retirement Plan for John W. Somerhalder II. (Exhibit 10.1.ay, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2008).
10.1.az	AGL Resources Inc. Excess Benefit Plan as amended and restated as of January 1, 2009. (Exhibit 10.1.az, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2008).
10.1.ba	Form of Continuity Agreement, dated December 1, 2011, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and certain officers, including John W. Somerhalder II, Andrew W. Evans, Henry P. Linginfelter, Paul R. Shlanta and Peter I. Tumminello (Exhibit 10.1, AGL Resources Inc. Form 8-K dated December 7, 2011).
10.1.bb	Description of compensation for each of John W. Somerhalder, Andrew W. Evans, Henry P. Linginfelter, Paul R. Shlanta, and Peter I. Tumminello (our Named Executive Officers for the year ended December 31, 2011) incorporated herein by reference to the Compensation Discussion and Analysis section of the AGL Resources Inc. Proxy Statement for the Annual Meeting of Shareholders held May 1, 2012 filed on March 16, 2012).
10.2	Guaranty Agreement, effective December 13, 2005, by and between Atlanta Gas Light Company and AGL Resources Inc. (Exhibit 10.2, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2006).
10.2.a	Form of Commercial Paper Dealer Agreement between AGL Capital Corporation, as Issuer, AGL Resources Inc., as Guarantor, and the Dealers named therein, dated September 25, 2000 (Exhibit 10.79, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 2000).
10.2.b	Guarantee of AGL Resources Inc., dated October 5, 2000, of payments on promissory notes issued by AGL

Capital Corporation (AGLCC) pursuant to the Issuing and Paying Agency Agreement dated September 25, 2000, between AGLCC and The Bank of New York (Exhibit 10.80, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 2000).

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

10.4 Note Purchase Agreement dated August 31, 2011, by and among AGL Capital Corporation as issuer, AGL Resources Inc. as guarantor and each of the note purchasers signatory thereto (Exhibit 10.1, AGL Resources Inc. Form 8-K filed September 7, 2011).

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

10.5.b Modification to the Amended and Restated Master Environmental Management Services Agreement, dated February 1, 2005 by and between Atlanta Gas Light Company and The RETEC Group, Inc. (Exhibit 10.6.b, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2008).

10.5.c Term Extension to the Amended and Restated Master Environmental Management Services Agreement, dated August 1, 2005 by and between Atlanta Gas Light Company and The RETEC Group, Inc. (Exhibit 10.6.c, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2008).

10.5.d Modification to the Amended and Restated Master Environmental Management Services Agreement, dated June 30, 2005 by and between Atlanta Gas Light Company and The RETEC Group, Inc. (Exhibit 10.6.d, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2008).

10.5.e Second Modification to the Amended and Restated Master Environmental Management Services Agreement, dated February 1, 2006 by and between Atlanta Gas Light Company and The RETEC Group, Inc. (Exhibit 10.6.e, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2008).

10.5.f Third Modification to the Amended and Restated Master Environmental Management Services Agreement, dated February 1, 2008 by and between Atlanta Gas Light Company and The RETEC Group, Inc. (Exhibit 10.6.f, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2008).

10.5.g Fourth Modification to the amended and Restated Master Environmental Management Services Agreement dated as of February 1, 2009 by and between Atlanta Gas Light Company and the RETEC Group, Inc. (Exhibit 10.6, AGL Resources Inc. Form 10-Q for the quarter ended March 31, 2009).

10.5.h Environmental Services Agreement, dated July 16, 2009, by and between Atlanta Gas Light Company and MACTEC Engineering and Consulting, Inc. (Exhibit 10.2, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2009).

10.5i Final Allocation Agreement, dated January 3, 2008, between Northern Illinois Gas Company and Commonwealth Edison Company (Exhibit 10.64, Nicor Inc. Form 10-K for the fiscal year ended December 31, 2007, File No. 001-07297).

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

10.6.b Third Amendment to Amended and Restated Limited Liability Company Agreement, dated July 29, 2009, by and between Georgia Natural Gas Company and Piedmont Energy Company (Exhibit 10, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2009).

10.7 Credit Facility, dated as of December 15, 2011 among Northern Illinois Gas Company, an Illinois corporation, as borrower, the several banks and other financial institutions or entities from time to time parties to this Agreement, as lenders, SunTrust Bank, as administrative agent and lender, Wells Fargo Bank, National Association and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as co-syndication agents and lenders, and JPMorgan Chase Bank, N.A. and U.S. Bank National Association, as co-documentation agents and lenders (Exhibit 10.1, AGL Resources Inc. Form 8-K filed December 15, 2011).

10.8.a Amended and Restated Credit Agreement, dated as of November 10, 2011, among AGL Resources Inc., as guarantor, AGL Capital Corporation, as borrower, Wells Fargo Bank, National Association, as administrative agent and issuing lender, SunTrust Bank and JPMorgan Chase Bank, N.A., as co-syndication agents, JPMorgan Chase Bank, N.A. as issuing lender, Bank of America, N.A. and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as co-documentation agents, and the several banks and other financial institutions or entities from time to time party thereto (Exhibit 10.1, AGL Resources Inc. Form 8-K filed November 17, 2011).

10.8.b Guarantee Agreement, dated as of November 10, 2011, made by AGL Resources Inc., as guarantor, in favor of Wells Fargo Bank, National Association, as administrative agent for the several banks and other financial institutions or entities from time to time party to the Amended and Restated Credit Agreement, dated as of the date thereof, among AGL Resources Inc., AGL Capital Corporation, the lenders named therein, and Wells Fargo Bank, National Association, as administrative agent (Exhibit 10.2, AGL Resources Inc. Form 8-K filed November 17, 2011).

10.9.a Credit Agreement as of September 15, 2010 by and among AGL Resources Inc., AGL Capital Corporation, Wells Fargo Bank, National Association, as administrative agent, Wells Fargo Securities, LLC, Banc of America Securities LLC and SunTrust Robinson Humphrey, Inc., as joint arrangers and joint bookrunners, and the several other banks and other financial institutions named therein, Bank of America, N.A. and SunTrust Bank, as Co-Syndication Agents, and The Bank of Tokyo-Mitsubishi, UFJ, Ltd., and JPMorgan Chase Bank, N.A., as Co-Documentation Agents (Exhibit 10.1, AGL Resources Inc. Form 8-K filed September 20, 2010).

10.9.b First Amendment as of December 21, 2010 to Credit Agreement as of September 15, 2010 by and among AGL Resources Inc., AGL Capital Corporation, Wells Fargo Bank, National Association, as administrative agent, Wells Fargo Securities, LLC, Banc of America Securities LLC and SunTrust Robinson Humphrey, Inc., as joint arrangers and bookrunners, and the several other banks and other financial institutions named therein, Bank of America, N.A. and SunTrust Bank, as co-syndication agents, and The Bank of Tokyo-Mitsubishi, UFJ, Ltd., and JPMorgan Chase Bank, N.A., as co-documentation agents (Exhibit 10.5, AGL Resources Inc. Form 8-K filed December 23, 2010).

10.9.c Second Amendment as of August 11, 2011 to Credit Agreement as of September 15, 2010, as amended, by and among AGL Capital Corporation, AGL Resources Inc., Wells Fargo Bank, National Association, as administrative agent, and the several lenders named therein (Exhibit 10.3, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2011).

10.10.d Guarantee, dated as of September 15, 2010 made by AGL Resources Inc., the guarantor, in favor of Wells Fargo Bank, National Association, as administrative agent for the lenders parties to the Credit Agreement, dated as of September 15, 2010, among Guarantor, AGL Capital Corporation, the borrower, the lenders named therein, and Wells Fargo Bank, National Association, as administrative agent (Exhibit 10.2, AGL Resources Inc. Form 8-K filed September 20, 2010).

10.11.a Reimbursement Agreement dated as of October 14, 2010, by and among Pivotal Utility Holdings, Inc., AGL Resources Inc., JPMorgan Chase Bank, N.A., as administrative agent and lead arranger, and the several other banks and other financial institutions named therein (Exhibit 10.1, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2010).

10.11.b First Amendment dated as of December 17, 2010 to Reimbursement Agreement dated as of October 14, 2010, by and among Pivotal Utility Holdings, Inc., AGL Resources Inc., JPMorgan Chase Bank, N.A., as administrative agent and lead arranger, and the several other banks and other financial institutions named therein (Exhibit 10.9, AGL Resources Inc. Form 8-K, dated December 23, 2010).

10.11.c Second Amendment dated as of August 11, 2011 to Reimbursement Agreement dated as of October 14, 2010, as amended, by and among Pivotal Utility Holdings, Inc., AGL Resources Inc., JPMorgan Chase Bank, N.A., as administrative agent and lead arranger, and the several other banks and other financial institutions named therein (Exhibit 10.4, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2011).

10.11.d Third Amendment, dated as of May 21, 2012, to Reimbursement Agreement, dated as of October 14, 2010, by and among Pivotal Utility Holdings, Inc., AGL Resources Inc., JPMorgan Chase Bank, N.A., as administrative agent and lead arranger, and the several other banks and other financial institutions named therein (Exhibit 10.1, AGL Resources Inc. Form 8-K filed May 25, 2012).

10.12.a Reimbursement Agreement dated as of October 14, 2010, by and among Pivotal Utility Holdings, Inc., AGL Resources Inc., The Bank of Tokyo-Mitsubishi UFJ, Ltd, New York Branch, as administrative agent and lead arranger, and the several other banks and other financial institutions named therein. (Exhibit 10.2, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2010).

10.12.b First Amendment, dated as of December 17, 2010 to Reimbursement Agreement dated as of October 14, 2010, by and among Pivotal Utility Holdings, Inc., AGL Resources Inc., and The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch, as administrative agent and lead arranger, and the several other banks and other financial institutions named therein (Exhibit 10.8, AGL Resources Inc. Form 8-K, dated December 23, 2010).

10.12.c Second Amendment dated as of August 11, 2011 to Reimbursement Agreement dated as of October 14, 2010, as amended, by and among Pivotal Utility Holdings, Inc., AGL Resources Inc., The Bank of Tokyo-Mitsubishi UFJ, Ltd, New York Branch,, as administrative agent and lead arranger, and the several other banks and other financial institutions named therein (Exhibit 10.5, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2011).

10.12.d Third Amendment, dated as of May 21, 2012, to Reimbursement Agreement, dated as of October 14, 2010, by and among Pivotal Utility Holdings, Inc., AGL Resources Inc., The Bank of Tokyo-Mitsubishi UFJ, Ltd, New York Branch, as administrative agent and lead arranger, and the several other banks and other financial institutions named therein (Exhibit 10.2, AGL Resources Inc. Form 8-K filed May 25, 2012).

10.13.a Reimbursement Agreement dated as of October 14, 2010, by and among Pivotal Utility Holdings, Inc., AGL

	Resources Inc., The Bank of Tokyo-Mitsubishi UFJ, Ltd, New York Branch, as administrative agent and lead arranger, and the several other banks and other financial institutions named therein. (Exhibit 10.3, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2010).
10.13.b	First Amendment dated as of December 17, 2010 to Reimbursement Agreement dated as of October 14, 2010, by and among Pivotal Utility Holdings, Inc., AGL Resources Inc., and The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch, as administrative agent and lead arranger, and the several other banks and other financial institutions named therein (Exhibit 10.7, AGL Resources Inc. Form 8-K, dated December 23, 2010).
10.13.c	Second Amendment dated as of August 11, 2011 to Reimbursement Agreement dated as of October 14, 2010, as amended, by and among Pivotal Utility Holdings, Inc., AGL Resources Inc., The Bank of Tokyo-Mitsubishi UFJ, Ltd, New York Branch, as administrative agent and lead arranger, and the several other banks and other financial institutions named therein (Exhibit 10.6, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2011).
10.13.d	Third Amendment, dated as of May 21, 2012, to Reimbursement Agreement, dated as of October 14, 2010, by and among Pivotal Utility Holdings, Inc., AGL Resources Inc., The Bank of Tokyo-Mitsubishi UFJ, Ltd, New York Branch, as administrative agent and lead arranger, and the several other banks and other financial institutions named therein (Exhibit 10.3, AGL Resources Inc. Form 8-K filed May 25, 2012).
10.14.a	Reimbursement Agreement dated as of October 14, 2010, by and among Pivotal Utility Holdings, Inc., AGL Resources Inc., JPMorgan Chase Bank, N.A., as administrative agent and lead arranger, and the several other banks and other financial institutions named therein. (Exhibit 10.4, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2010).
10.14.b	First Amendment, dated as of December 17, 2010 to Reimbursement Agreement dated as of October 14, 2010, by and among Pivotal Utility Holdings, Inc., AGL Resources Inc. and JPMorgan Chase Bank, N.A., as administrative agent and the several other banks and other financial institutions named therein (Exhibit 10.6, AGL Resources Inc. Form 8-K, dated December 23, 2010).
10.14.c	Second Amendment dated as of August 11, 2011 to Reimbursement Agreement dated as of October 14, 2010, as amended, by and among Pivotal Utility Holdings, Inc., AGL Resources Inc., JPMorgan Chase Bank, N.A., as administrative agent and lead arranger, and the several other banks and other financial institutions named therein (Exhibit 10.7, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2011).
10.14.d	Third Amendment, dated as of May 21, 2012, to Reimbursement Agreement, dated as of October 14, 2010, by and among Pivotal Utility Holdings, Inc., AGL Resources Inc., JPMorgan Chase Bank, N.A., as administrative agent and lead arranger, and the several other banks and other financial institutions named therein (Exhibit 10.4, AGL Resources Inc. Form 8-K filed May 25, 2012).
12	Statement of Computation of Ratio of Earnings to Fixed Charges.
14	AGL Resources Inc. Code of Ethics for its Chief Executive Officer and its Senior Financial Officers (Exhibit 14, AGL Resources Inc. Form 10-K for the year ended December 31, 2004).
21	Subsidiaries of AGL Resources Inc.
23	Consent of PricewaterhouseCoopers LLP, independent registered public accounting firm.
24	Powers of Attorney (included on signature page hereto).
31.1	Certification of John W. Somerhalder II pursuant to Rule 13a - 14(a).
31.2	Certification of Andrew W. Evans pursuant to Rule 13a - 14(a).
32.1	Certification of John W. Somerhalder II pursuant to 18 U.S.C. Section 1350.
32.2	Certification of Andrew W. Evans pursuant to 18 U.S.C. Section 1350.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.
101.DEF	XBRL Taxonomy Definition Linkbase.
101.LAB	XBRL Taxonomy Extension Labels Linkbase.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.

(b) Exhibits filed as part of this report.

See Item 15(a)(3).

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

See Item 15(a)(2).

SIGNATURES

In accordance with Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned; thereunto duly authorized, on February 6, 2013.

AGL RESOURCES INC.

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

Power of Attorney

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints John W. Somerhalder II, Andrew W. Evans, Paul R. Shlanta and Bryan E. Seas, and each of them, his or her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K for the year ended December 31, 2012, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite or necessary to be done, as fully to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated as of February 6, 2013.

Signatures	Title
/s/ John W. Somerhalder II John W. Somerhalder II	Chairman, President and Chief Executive Officer (Principal Executive Officer)
/s/ Andrew W. Evans Andrew W. Evans	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ Bryan E. Seas Bryan E. Seas	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)
/s/ Sandra N. Bane Sandra N. Bane	Director
/s/ Thomas D. Bell, Jr. Thomas D. Bell, Jr.	Director
/s/ Norman R. Bobins Norman R. Bobins	Director
/s/ Charles R. Crisp Charles R. Crisp	Director
/s/ Brenda J. Gaines Brenda J. Gaines	Director
/s/ Arthur E. Johnson Arthur E. Johnson	Director
/s/ Wyck A. Knox, Jr. Wyck A. Knox, Jr.	Director
/s/ Dennis M. Love Dennis M. Love	Director
/s/ Charles H. McTier Charles H. McTier	Director
/s/ Dean R. O'Hare Dean R. O'Hare	Director
/s/ Armando J. Olivera Armando J. Olivera	Director
/s/ John E. Rau John E. Rau	Director
/s/ James A. Rubright James A. Rubright	Director
/s/ Bettina M. Whyte Bettina M. Whyte	Director
/s/ Henry C. Wolf Henry C. Wolf	Director

Schedule II

AGL Resources Inc. and Subsidiaries

VALUATION AND QUALIFYING ACCOUNTS - FOR EACH OF THE THREE YEARS IN THE PERIOD ENDED DECEMBER 31, 2012.

Description	Balance at beginning of period	Additions: Charged to costs and expenses	Additions: Charged to other accounts	Deductions	Balance at end of period
2010					
Allowance for uncollectible accounts	$14	$22	$0	$(20)	$16
Income tax valuation	3	0	0	0	3
2011					
Allowance for uncollectible accounts	$16	$20	$0	$(19)	$17
Income tax valuation	3	0	0	0	3
2012					
Allowance for uncollectible accounts	$17	$25	$3	$(17)	$28
Income tax valuation	3	0	19	0	22

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

CERTIFICATIONS

I, John W. Somerhalder II, certify that:

1. I have reviewed this annual report on Form 10-K of AGL Resources Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 6, 2013

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

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

CERTIFICATIONS

I, Andrew W. Evans, certify that:

1. I have reviewed this annual report on Form 10-K of AGL Resources Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 6, 2013

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

Annual Meeting

The 2013 annual meeting of shareholders will be held Tuesday, April 30, 2013, at AGL Resources' corporate headquarters, Ten Peachtree Place, N.E., Atlanta, GA 30309.

ResourcesDIRECT™

New investors may make an initial investment, and shareholders of record may acquire additional shares of our common stock, through ResourcesDIRECT™ without paying brokerage fees or service charges. Initial cash investments, quarterly cash dividends and/or optional cash purchases may be invested through the plan prospectus and enrollment materials. Contact our transfer agent at 800-468-9716 or visit our website at aglresources.com.

Holders of Common Stock, Stock Price and Dividend Information

At January 31, 2013, there were 22,221 record holders of our common stock. Quarterly information concerning our high and low stock prices and cash dividends paid in 2012 and 2011 is as follows:

2012

	Sales price of common stock			Cash dividend per
Quarter ended	High	Low	Close	common share
March 31, 2012[1]	$42.88	$38.42	$39.22	$0.36
June 30, 2012	40.29	36.59	38.75	0.46
September 30, 2012	41.95	38.45	40.91	0.46
December 31, 2012	41.71	36.90	39.97	0.46
				$1.74

2011

	Sales price of common stock			Cash dividend per
Quarter ended	High	Low	Close	common share
March 31, 2011	$39.91	$35.65	$39.84	$0.45
June 30, 2011	42.34	38.58	40.71	0.45
September 30, 2011	42.40	34.08	40.74	0.45
December 31, 2011[1]	43.69	37.95	42.26	0.55
				$1.90

[1] As a result of the Nicor merger, AGL Resources shareholders of record as of the close of business on December 8, 2011, received a pro rata dividend of $0.0989 for the stub period, accruing from November 19, 2011, which increased the fourth quarter 2011 dividend and reduced the first quarter 2012 dividend by an equal amount. For presentation purposes the amount in the table was rounded to $0.10.

We have historically paid dividends to common shareholders four times a year: March 1, June 1, September 1 and December 1. We have paid 261 consecutive quarterly dividends beginning in 1948. Our common shareholders may receive dividends when declared at the discretion of our Board of Directors, and payment of future dividends will depend on our future earnings, cash flow, financial requirements and other factors. In February 2013, we increased our quarterly dividend to $0.47 per share.

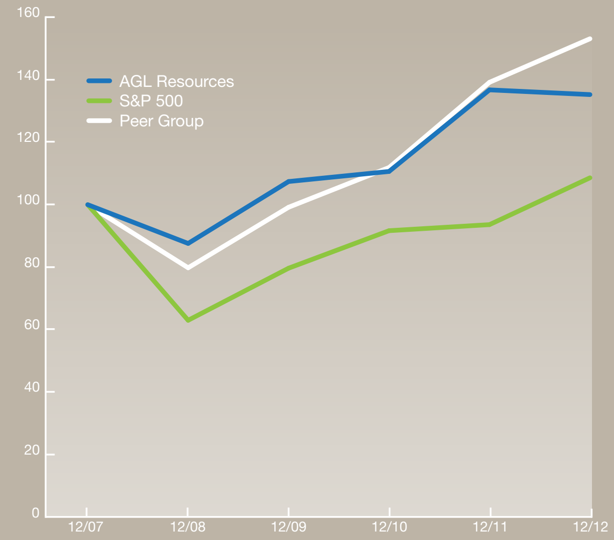
Stock Exchange Listing

Our common stock is traded on the New York Stock Exchange under the symbol "GAS" and quoted in The Wall Street Journal as "AGL Res."

Comparison of Five-Year Cumulative Total Return*

The following graph compares the cumulative five-year total return provided shareholders on AGL Resources Inc's common stock relative to the cumulative total returns of the S&P 500 index, and a customized peer group of twelve companies listed in footnote 1 below. An investment of $100 (with reinvestment of all dividends) is assumed to have been made in our common stock, in the peer group, and the index on 12/31/2007 and its relative performance is tracked through 12/31/2012.

[1] There are twelve companies included in the customized peer group which are: Atmos Energy Corp., Centerpoint Energy Inc., Integrys Energy Group Inc., New Jersey Resources Corp., NiSource Inc., Oneok Inc., Piedmont Natural Gas Company Inc., Sempra Energy, Southwest Gas Corp., UGI Corp., Vectren Corp. and WGL Holdings Inc.



	12/07	12/08	12/09	12/10	12/11	12/12
AGL Resources Inc	100.00	87.59	107.40	110.62	136.73	135.22
S&P 500©	100.00	63.00	79.67	91.67	93.61	108.59
Peer Group	100.00	79.80	99.17	111.88	139.15	152.08

* $100 invested on 12/31/07 in stock or index, including reinvestment of dividends. Fiscal year ending December 31.

The stock price performance included in this graph is not necessarily indicative of future stock price performance.

AGL Resources™

aglresources.com

Attachment 9

Footnotes to AGL Resources Inc.'s Financial Statements Setting Forth Federal Income Taxes In Annual Reports 2004 - 2012

Note 11
FAIR VALUE OF FINANCIAL INSTRUMENTS

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

In millions	Carrying Amount	Estimated Fair Value
As of December 31, 2004		
Long-term debt including current portion	**$1,623**	**$1,816**
As of December 31, 2003		
Long-term debt including current portion	1,033	1,166

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

Considerable judgment is required to develop the fair value estimates; therefore, the values are not necessarily indicative of the amounts that could be realized in a current market exchange. The fair value estimates are based on information available to management as of December 31, 2004. We are not aware of any subsequent factors that would significantly affect the estimated fair value amounts. For more information about the fair values of our interest rate swaps, see Note 4.

Note 12
INCOME TAXES

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

INVESTMENT TAX CREDITS

Deferred investment tax credits associated with distribution operations are included as a regulatory liability in our consolidated balance sheets (see Note 5). These investment tax credits are being amortized over the estimated life of the related properties as credits to income in accordance with regulatory treatment. We reduce income tax expense in our statements of consolidated income for the investment tax credits and other tax credits associated with our nonregulated subsidiaries. Components of income tax expense shown in the statements of consolidated income are as follows:

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

12

Income Taxes

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

Investment Tax Credits

Deferred investment tax credits associated with distribution operations are included as a regulatory liability in our consolidated balance sheets (see Note 5). These investment tax credits are being amortized over the estimated life of the related properties as credits to income in accordance with regulatory requirements. We reduce income tax expense in our statements of consolidated income for the investment tax credits and other tax credits associated with our nonregulated subsidiaries. Components of income tax expense shown in the statements of consolidated income are as follows.

In millions	2005	2004	2003
Current income taxes			
Federal	**$ 84**	$25	$20
State	**18**	1	13
Deferred income taxes			
Federal	**17**	60	52
State	**—**	5	3
Amortization of investment tax credits	**(2)**	(1)	(1)
Total	**$117**	$90	$87

The reconciliations between the statutory federal income tax rate, the effective rate and the related amount of tax for the years ended December 31, 2005, 2004 and 2003 are presented below.

Dollars in millions	Amount	% of pretax income
2005		
Computed tax expense at statutory rate	**$109**	**35.0%**
State income tax, net of federal income tax benefit	**11**	**3.7**
Amortization of investment tax credits	**(2)**	**(0.6)**
Flexible dividend deduction	**(2)**	**(0.6)**
Other—net	**1**	**0.2**
Total income tax expense at effective rate	**$117**	**37.7%**
2004		
Computed tax expense at statutory rate	$ 85	35.0%
State income tax, net of federal income tax benefit	9	3.5
Amortization of investment tax credits	(1)	(0.6)
Flexible dividend deduction	(2)	(0.6)
Other—net	(1)	(0.2)
Total income tax expense at effective rate	$ 90	37.1%
2003		
Computed tax expense at statutory rate	$ 78	35.0%
State income tax, net of federal income tax benefit	8	3.8
Amortization of investment tax credits	(1)	(0.6)
Flexible dividend deduction	(1)	(0.6)
Other—net	3	1.4
Total income tax expense at effective rate	$ 87	39.0%

Notes

Note 9 » Fair Value of Financial Instruments

The following table shows the carrying amounts and fair values of our long-term debt including any current portions included in our consolidated balance sheets.

In millions	Carrying amount[1]	Estimated fair value
As of December 31, 2006	**$1,633**	**$1,716**
As of December 31, 2005	1,615	1,784

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

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

Considerable judgment is required to develop the fair value estimates; therefore, the values are not necessarily indicative of the amounts that could be realized in a current market exchange. The fair value estimates are based on information available to management as of December 31, 2006. We are not aware of any subsequent factors that would significantly affect the estimated fair value amounts. For more information about the fair values of our interest rate swaps, see Note 2.

Note 10 » Income Taxes

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

Investment Tax Credits

Deferred investment tax credits associated with distribution operations are included as a regulatory liability in our consolidated balance sheets (see Note 3, Regulatory Assets and Liabilities). These investment tax credits are being amortized over the estimated life of the related properties as credits to income in accordance with regulatory requirements. We reduce income tax expense in our statements of consolidated income for the investment tax credits and other tax credits associated with our nonregulated subsidiaries. Components of income tax expense shown in the statements of consolidated income are as follows.

Income Tax Expense

The relative split between current and deferred taxes is due to a variety of factors including true-ups of prior year tax returns, and most importantly, the timing of our property-related deductions. Additionally, 2006 was significantly impacted by our mark-to-market gains on energy risk management assets which are not recognized for tax purposes until realized.

In millions	**2006**	2005	2004
Current income taxes			
Federal	**$ (4)**	$ 84	$25
State	**2**	18	1
Deferred income taxes			
Federal	**115**	17	60
State	**18**	—	5
Amortization of investment tax credits	**(2)**	(2)	(1)
Total	**$129**	$117	$90

Notes to Consolidated Financial Statements

Note 8 Income Taxes

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

Investment and Other Tax Credits

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

Components of income tax expense shown in the statements of consolidated income are shown in the following table.

Income Tax Expense

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

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

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

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

Notes to Consolidated Financial Statements

unconstitutional and have sought to amend the pending litigation to seek a declaration that the legislation is invalid and cannot be enforced. Even if we are not successful on those grounds, we believe the legislation does not materially impact the feasibility of the expansion project. If we are unable to reach a settlement, we are not able to predict the outcome of the litigation. As of January 2009, our current estimate of costs incurred that would be considered unusable if the Louisiana DNR was successful in terminating our lease and causing us to cease the expansion project is approximately $6 million.

In February 2008, the consumer affairs staff of the Georgia Commission alleged that GNG charged its customers on variable rate plans prices for natural gas that were in excess of the published price, that it failed to give proper notice regarding the availability of potentially lower price plans and that it changed its methodology for computing variable rates. GNG asserted that it fully complied with all applicable rules and regulations, that it properly charged its customers on variable rate plans the rates on file with the Georgia Commission, and that, consistent with its terms and conditions of service, it routinely switched customers who requested to move to another price plan for which they qualified. In order to resolve this matter GNG agreed to pay $2.5 million in the form of credits to customers, or as directed by the Georgia Commission, which was recorded in our statements of consolidated income for the year ended December 31, 2008.

In February 2008, a class action lawsuit was filed in the Superior Court of Fulton County in the State of Georgia against GNG containing similar allegations to those asserted by the Georgia Commission staff and seeking damages on behalf of a class of GNG customers. This lawsuit was dismissed in September 2008. In October 2008, the plaintiffs appealed the dismissal of the lawsuit and the parties are in the process of filing briefs on that appeal.

In March 2008, a second class action suit was filed against GNG in the State Court of Fulton County in the State of Georgia, regarding monthly service charges. This lawsuit alleges that GNG arbitrarily assigned customer service charges rather than basing each customer service charge on a specific credit score. GNG asserts that no violation of law or Georgia Commission rules has occurred, that this lawsuit is without merit and has filed motions to dismiss this class action suit on various grounds. The ultimate resolution of this lawsuit cannot be determined, but is not expected to have a material adverse effect on our consolidated results of operations, cash flows or financial condition.

Review of Compliance with FERC Regulations

In 2008, we conducted an internal review of our compliance with FERC interstate natural gas pipeline capacity release rules and regulations. Independent of our internal review, we also received data requests from FERC's Office of Enforcement relating specifically to compliance with FERC's capacity release posting and bidding requirements. We have responded to FERC's data requests and are fully cooperating with FERC in its investigation. As a result of this process, we have identified certain instances of possible non-compliance. We are committed to full regulatory compliance and we have met with the FERC Enforcement staff to discuss with them these instances of possible non-compliance. Accordingly we have accrued an appropriate estimate of possible penalties assessed by the FERC. This estimate does not have, and management does not believe the ultimate resolution will have, a material financial impact to our consolidated results of operations, cash flows or financial condition.

Note 8 Income Taxes

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

Investment and Other Tax Credits

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

Income Tax Expense

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

In millions	**2008**	2007	2006
Current income taxes			
Federal	**$ 37**	$ 86	$ (4)
State	**7**	12	2
Deferred income taxes			
Federal	**77**	23	115
State	**12**	7	18
Amortization of investment tax credits	**(1)**	(1)	(2)
Total	**$132**	$127	$129

Note 8 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 (see Note 1, "Accounting Policies and Methods of Application"). These investment tax credits are being amortized over the estimated life of the related properties as credits to income in accordance with regulatory requirements. In 2007, we invested in a guaranteed affordable housing tax credit fund. We reduce income tax expense in our consolidated statements of income for the investment tax credits and other tax credits associated with our nonregulated subsidiaries, including the affordable housing credits. Components of income tax expense shown in the consolidated statements of income are shown in the following table.

Income Tax Expense

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

In millions	2009	2008	2007
Current income taxes			
Federal	**$ 22**	$ 37	$ 86
State	**8**	7	12
Deferred income taxes			
Federal	**95**	77	23
State	**11**	12	7
Amortization of investment tax credits	**(1)**	(1)	(1)
Total	**$135**	$132	$127

The reconciliations between the statutory federal income tax rate, the effective rate and the related amount of tax for the years ended December 31, 2009, 2008 and 2007 on our consolidated statements of income are presented in the following table. Our adoption of the authoritative guidance relating to consolidations (see Note 5) had no effect on the total income tax expense reported in our consolidated statements of income or on our accrued federal and state income taxes, including accumulated deferred income taxes as reported in our consolidated statements of financial position.

In millions	2009	2008	2007
Computed tax expense at statutory rate	**$134**	$129	$129
State income tax, net of federal income tax benefit	**16**	15	14
Tax effect of net income attributable to the noncontrolling interest	**(11)**	(8)	(12)
Amortization of investment tax credits	**(1)**	(1)	(1)
Affordable housing credits	**(2)**	(2)	(1)
Flexible dividend deduction	**(2)**	(2)	(2)
Other – net	**1**	1	–
Total income tax expense on consolidated statements of income	**$135**	$132	$127

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 (see Note 1). Our deferred tax assets include $74 million related to an unfunded pension and postretirement benefit obligation a decrease of $11 million from 2008.

Note 11 ~ Income Taxes

Income Tax Expense

The relative split between current and deferred taxes is due to a variety of factors including true ups of prior year tax returns, and most importantly, the timing of our property-related deductions. Components of income tax expense shown in the Consolidated Statements of Income are shown in the following table.

In millions	2010	2009	2008
Current income taxes			
Federal	$37	$23	$37
State	12	8	7
Deferred income taxes			
Federal	86	94	77
State	6	11	12
Amortization of investment tax credits	(1)	(1)	(1)
Total	$140	$135	$132

The reconciliations between the statutory federal income tax rate, the effective rate and the related amount of tax for the years ended December 31, 2010, 2009 and 2008 on our Consolidated Statements of Income are presented in the following table.

In millions	2010	2009	2008
Computed tax expense at statutory rate	$136	$134	$129
State income tax, net of federal income tax benefit	15	16	15
Tax effect of net income attributable to the noncontrolling interest	(6)	(11)	(8)
Amortization of investment tax credits	(1)	(1)	(1)
Affordable housing credits	(2)	(2)	(2)
Flexible dividend deduction	(2)	(2)	(2)
Other – net	-	1	1
Total income tax expense on Consolidated Statements of Income	$140	$135	$132

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 (see Note 2). Our deferred tax assets include $94 million related to an unfunded pension and postretirement benefit obligation, an increase of $20 million from 2009.

We have provided a valuation allowance for some of these items that reduce our net deferred tax assets to amounts we believe are more likely than not to be realized in future periods. With respect to our continuing operations, we have net operating losses in various jurisdictions. Components that give rise to the net accumulated deferred income tax liability are as follows.

In millions	As of December 31, 2010	2009
Accumulated deferred income tax liabilities		
Property – accelerated depreciation and other property-related items	$863	$760
Mark to market	11	9
Other	-	2
Total accumulated deferred income tax liabilities	874	771
Accumulated deferred income tax assets		
Deferred investment tax credits	4	5
Unfunded pension and postretirement benefit obligation	94	74
Other	11	-
Total accumulated deferred income tax assets	109	79
Valuation allowances (1)	(3)	(3)
Total accumulated deferred income tax assets, net of valuation allowance	106	76
Net accumulated deferred tax liability	$768	$695

(1) Valuation allowance is due to the net operating losses on a former non-operating subsidiary that are not allowed in New Jersey.

Tax Benefits

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. As of December 31, 2010, we did not have a liability recorded for payment of interest and penalties associated with uncertain tax positions.

We file a United States federal consolidated income tax return and various state income tax returns. We are no longer subject to income tax examinations by the Internal Revenue Service for years before 2008 or in any state for years before 2006.

investigation relates to billing practices used with certain customer accounts involving government funds. While we believe the billing practices comply with Illinois Commission requirements, we are unable to predict the outcome of this matter or reasonably estimate its potential exposure, if any, and have not recorded a liability associated with this matter.

Other In addition to the matters set forth above, we are involved in legal or administrative proceedings before various courts and agencies with respect to general claims, taxes, environmental, gas cost prudence reviews and other matters. Although unable to determine the ultimate outcome of these other contingencies, we believe that these amounts are appropriately reflected in our financial statements, including the recording of appropriate liabilities when reasonably estimable.

Note 12 Income Taxes

Income Tax Expense

The relative split between current and deferred taxes is due to a variety of factors including true ups of prior year tax returns, and most importantly, the timing of our property-related deductions. Components of income tax expense shown in the Consolidated Statements of Income are shown in the following table.

In millions	2011	2010	2009
Current income taxes			
Federal	**$ (89)**	$ 37	$ 23
State	**1**	12	8
Deferred income taxes			
Federal	**196**	86	94
State	**18**	6	11
Amortization of investment tax credits	**(1)**	(1)	(1)
Total	**$125**	$140	$135

The reconciliations between the statutory federal income tax rate, the effective rate and the related amount of tax for the years ended December 31, 2011, 2010 and 2009 on our Consolidated Statements of Income are presented in the following table.

In millions	2011	2010	2009
Computed tax expense at statutory rate	**$109**	$136	$134
State income tax, net of federal income tax benefit	**14**	15	16
Tax effect of net income attributable to the noncontrolling interest	**(6)**	(6)	(11)
Amortization of investment tax credits	**(1)**	(1)	(1)
Affordable housing credits	**(1)**	(2)	(2)
Flexible dividend deduction	**(2)**	(2)	(2)
Change in control payments	**9**	—	—
Merger transaction costs	**3**	—	—
Other – net	**—**	—	1
Total income tax expense on Consolidated Statements of Income	**$125**	$140	$135

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 rate-regulated entities, which we are amortizing over approximately 30 years (see Note 2). Our deferred tax assets include $137 million related to an unfunded pension and other retirement benefit obligation, an increase of $43 million from 2010.

Other In addition to the matters set forth above, we are involved with legal or administrative proceedings before various courts and agencies with respect to general claims, taxes, environmental, gas cost prudence reviews and other matters. Although we are unable to determine the ultimate outcome of these other contingencies, we believe that these amounts are appropriately reflected in our financial statements, including the recording of appropriate liabilities when reasonably estimable.

Note 12 - Income Taxes

Income Tax Expense

The relative split between current and deferred taxes is due to a variety of factors including true ups of prior year tax returns, and most importantly, the timing of our property-related deductions. Components of income tax expense shown in the Consolidated Statements of Income are shown in the following table.

In millions	**2012**	**2011**	**2010**
Current income taxes			
Federal	$9	$(89)	$37
State	4	1	12
Deferred income taxes			
Federal	134	196	86
State	20	18	6
Amortization of investment tax credits	(3)	(1)	(1)
Total	$164	$125	$140

The reconciliations between the statutory federal income tax rate, the effective rate and the related amount of tax for the years ended December 31, 2012, 2011 and 2010 on our Consolidated Statements of Income are presented in the following table.

In millions	**2012**	**2011**	**2010**
Computed tax expense at statutory rate	$158	$109	$136
State income tax, net of federal income tax benefit	19	14	15
Tax effect of net income attributable to the noncontrolling interest	(6)	(6)	(6)
Amortization of investment tax credits	(3)	(1)	(1)
Affordable housing credits	(2)	(1)	(2)
Flexible dividend deduction	(2)	(2)	(2)
Change in control payments	0	9	0
Merger transaction costs	0	3	0
Total income tax expense on Consolidated Statements of Income	$164	$125	$140

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 rate-regulated entities, which we are amortizing over approximately 30 years (see Note 2). Our deferred tax assets include $145 million related to an unfunded pension and other retirement benefit obligation, an increase of $8 million from 2011.

We have provided a valuation allowance for some of these items that reduce our net deferred tax assets to amounts we believe are more likely than not to be realized in future periods. With respect to our continuing