LARGE FILING SEPARATOR SHEET

CASE NUMBER 07-378-GA-CRS

FILE DATE 3-22-13

SECTION: 1 OF 5

NUMBER OF PAGES: 200

DESCRIPTION OF DOCUMENT:

RENEWAL APPLICATION

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Date Received	Renewal Certification Number	ORIGINAL CRS Case Number
		07 -0378 - GA-CRS

RENEWAL CERTIFICATION APPLICATION
COMPETITIVE RETAIL NATURAL GAS SUPPLIERS

Please **type or print** all required information. Identify all attachments with an exhibit label and title (***Example: Exhibit A-16 - Company History***). All attachments should bear the legal name of the Applicant. Applicants should file completed applications and all related correspondence with the Public Utilities Commission of Ohio, Docketing Division, 13th Floor, 180 East Broad Street, Columbus, Ohio 43215-3793.

This PDF form is designed so that you may directly input information onto the form. You may also download the form by saving it to your local disk.

SECTION A - APPLICANT INFORMATION AND SERVICES

A-1 Applicant intends to renew its certificate as: (check all that apply)

☑ **Retail Natural Gas Aggregator** ☑ **Retail Natural Gas Broker** ☑ **Retail Natural Gas Marketer**

A-2 Applicant information:

Legal Name: SouthStar Energy Services LLC

Address: 817 W. Peachtree Street, NW, Suite 1000, Atlanta, Georgia 30308

Telephone No. 404.685.4000 Web site Address www.southstarenergy.com

Current PUCO Certificate No. 07-127G(3) Effective Dates May 7, 2011 - May 7, 2013

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A-3 Applicant information under which applicant will do business in Ohio:

Name: SouthStar Energy Services LLC d/b/a Ohio Natural Gas

Address: 817 W. Peachtree Street, NW, Suite 1000, Atlanta, Georgia 30308

Web site Address www.onlyong.com Telephone No. 404.685.4000

A-4 *List all names under which the applicant does business in North America:*

SouthStar Energy Services
Georgia Natural Gas
Ohio Natural Gas
Florida Natural Gas
Piedmont Energy Company
New York Natural Gas
Maryland Energy

A-5 Contact person for regulatory or emergency matters:

Name Trish McFadin Title Director, Regulatory Affairs

Business Address 817 W. Peachtree Street NW, Suite 1000, Atlanta, Georgia 30308

Telephone No. 404.685.4095 Fax No. 404.685.4118 Email Address trish.mcfadin@southstarenergy.c

A-6 Contact person for Commission Staff use in investigating customer complaints:

Name Trish McFadin Title Director, Regulatory Affairs

Business address 817 W. Peachtree Street NW, Suite 1000, Atlanta, Georgia 30308

Telephone No. 404.685.4095 Fax No. 404.685.4118 Email Address trish.mcfadin@southstarenergy

A-7 Applicant's address and toll-free number for customer service and complaints

Customer service address Ohio Natural Gas, P.O. Box 14657, Cleveland, Ohio 44114

Toll-Free Telephone No. 888.466.4427 Fax No. 866.404.2680 Email Address customerservice@onlyong

A-8 Provide "Proof of an Ohio Office and Employee," in accordance with Section 4929.22 of the Ohio Revised Code, by listing name, Ohio office address, telephone number, and Web site address of the designated Ohio Employee

Name Daniel R. Conway Title Attorney

Business address 41 South High Street, Columbus, Ohio 43215-6194

Telephone No. 614.227.2270 Fax No. 614.227.2100 Email Address dconway@porterwright.com

A-9 Applicant's federal employer identification number 58-2402579

A-10 Applicant's form of ownership: (Check one)

☐ **Sole Proprietorship** ☐ **Partnership**

☐ **Limited Liability Partnership (LLP)** ☑ **Limited Liability Company (LLC)**

☐ **Corporation** ☐ **Other**

A-11 (Check all that apply) Identify each natural gas company service area in which the applicant is currently providing service or intends to provide service, including identification of each customer class that the applicant is currently serving or intends to serve, for example: *residential, small commercial, and/or large commercial/industrial (mercantile) customers.* (A mercantile customer, as defined in Section 4929.01(L)(1) of the Ohio Revised Code, means a customer that consumes, other than for residential use, more than 500,000 cubic feet of natural gas per year at a single location within the state or consumes natural gas, other than for residential use, as part of an undertaking having more than three locations within or outside of this state. In accordance with Section 4929.01(L)(2) of the Ohio Revised Code, "Mercantile customer" excludes a not-for-profit customer that consumes, other than for residential use, more than 500,000 cubic feet of natural gas per year at a single location within this state or consumes natural gas, other than for residential use, as part of an undertaking having more than three locations within or outside this state that has filed the necessary declaration with the Public Utilities Commission.)

✓ Columbia Gas of Ohio	✓ Residential	✓ Small Commercial	✓ Large Commercial / Industrial
✓ Dominion East Ohio	✓ Residential	✓ Small Commercial	✓ Large Commercial / Industrial
✓ Duke Energy Ohio	✓ Residential	✓ Small Commercial	✓ Large Commercial / Industrial
✓ Vectren Energy Delivery of Ohio	✓ Residential	✓ Small Commercial	✓ Large Commercial / Industrial

A-12 If applicant or an affiliated interest previously participated in any of Ohio's Natural Gas Choice Programs, for each service area and customer class, provide approximate start date(s) and/or end date(s) that the applicant began delivering and/or ended services.

✓ **Columbia Gas of Ohio**

✓ Residential	Beginning Date of Service	July 1, 2010	End Date
✓ Small Commercial	Beginning Date of Service	July 1, 2010	End Date
✓ Large Commercial	Beginning Date of Service	July 1, 2010	End Date
✓ Industrial	Beginning Date of Service	July 1, 2010	End Date

✓ **Dominion East Ohio**

✓ Residential	Beginning Date of Service	December 1, 2007	End Date
✓ Small Commercial	Beginning Date of Service	December 1, 2007	End Date
✓ Large Commercial	Beginning Date of Service	December 1, 2007	End Date
✓ Industrial	Beginning Date of Service	December 1, 2007	End Date

✓ **Duke Energy Ohio**

✓ Residential	Beginning Date of Service	August, 2012	End Date
✓ Small Commercial	Beginning Date of Service	August, 2012	End Date
✓ Large Commercial	Beginning Date of Service	August, 2012	End Date
✓ Industrial	Beginning Date of Service	August, 2012	End Date

✓ **Vectren Energy Delivery of Ohio**

✓ Residential	Beginning Date of Service	December 1, 2008	End Date
✓ Small Commercial	Beginning Date of Service	December 1, 2008	End Date
✓ Large Commercial	Beginning Date of Service	December 1, 2008	End Date
✓ Industrial	Beginning Date of Service	December 1, 2008	End Date

A-13 If not currently participating in any of Ohio's four Natural Gas Choice Programs, provide the approximate start date that the applicant proposes to begin delivering services:

☐	Columbia Gas of Ohio	Intended Start Date
☐	Dominion East Ohio	Intended Start Date
☐	Duke Energy Ohio	Intended Start Date
☐	Vectren Energy Delivery of Ohio	Intended Start Date

PROVIDE THE FOLLOWING AS SEPARATE ATTACHMENTS AND LABEL AS INDICATED.

A-14 **Exhibit A-14 "Principal Officers, Directors & Partners,"** provide the names, titles, addresses and telephone numbers of the applicant's principal officers, directors, partners, or other similar officials.

A-15 **Exhibit A-15 "Corporate Structure,"** provide a description of the applicant's corporate structure, including a graphical depiction of such structure, and a list of all affiliate and subsidiary companies that supply retail or wholesale natural gas or electricity to customers in North America.

A-16 **Exhibit A-16 "Company History,"** provide a concise description of the applicant's company history and principal business interests.

A-17 **Exhibit A-17 "Articles of Incorporation and Bylaws**, provide the articles of incorporation filed with the state or jurisdiction in which the applicant is incorporated and any amendments thereto, ***only if the contents of the originally filed documents changed since the initial application***.

A-18 **Exhibit A-18 "Secretary of State,"** provide evidence that the applicant is still currently registered with the Ohio Secretary of the State.

SECTION B - APPLICANT MANAGERIAL CAPABILITY AND EXPERIENCE

PROVIDE THE FOLLOWING AS SEPARATE ATTACHMENTS AND LABEL AS INDICATED

B-1 **Exhibit B-1 "Jurisdictions of Operation,"** provide a current list of all jurisdictions in which the applicant or any affiliated interest of the applicant is, at the date of filing the application, certified, licensed, registered, or otherwise authorized to provide retail natural gas service, or retail/wholesale electric services.

B-2 **Exhibit B-2 "Experience & Plans,"** provide a current description of the applicant's experience and plan for contracting with customers, providing contracted services, providing billing statements, and responding to customer inquiries and complaints in accordance with Commission rules adopted pursuant to Section 4929.22 of the Revised Code and contained in Chapter 4901:1-29 of the Ohio Administrative Code.

B-3 **Exhibit B-3 "Summary of Experience,"** provide a concise and current summary of the applicant's experience in providing the service(s) for which it is seeking renewed certification (e.g., number and types of customers served, utility service areas, volume of gas supplied, etc.).

B-4 **Exhibit B-4 "Disclosure of Liabilities and Investigations,"** provide a description of all existing, pending or past rulings, judgments, contingent liabilities, revocations of authority, regulatory investigations, or any other matter that could adversely impact the applicant's financial or operational

status or ability to provide the services for which it is seeking renewed certification since applicant last filed for certification.

B-5 **Exhibit B-5 "Disclosure of Consumer Protection Violations,"** disclose whether the applicant, affiliate, predecessor of the applicant, or any principal officer of the applicant has been convicted or held liable for fraud or for violation of any consumer protection or antitrust laws since applicant last filed for certification.

☑ **No** ☐ **Yes**

If Yes, provide a separate attachment labeled as Exhibit B-5 "Disclosure of Consumer Protection Violations," detailing such violation(s) and providing all relevant documents.

B-6 **Exhibit B-6 "Disclosure of Certification Denial, Curtailment, Suspension, or Revocation,"** disclose whether the applicant or a predecessor of the applicant has had any certification, license, or application to provide retail natural gas or retail/wholesale electric service denied, curtailed, suspended, or revoked, or whether the applicant or predecessor has been terminated from any of Ohio's Natural Gas Choice programs, or been in default for failure to deliver natural gas since applicant last filed for certification.

☑ **No** ☐ **Yes**

If Yes, provide a separate attachment, labeled as Exhibit B-6 "Disclosure of Certification Denial, Curtailment, Suspension, or Revocation," detailing such action(s) and providing all relevant documents.

SECTION C - APPLICANT FINANCIAL CAPABILITY AND EXPERIENCE

PROVIDE THE FOLLOWING AS SEPARATE ATTACHMENTS AND LABEL AS INDICATED

C-1 **Exhibit C-1 "Annual Reports,"** provide the two most recent Annual Reports to Shareholders. If applicant does not have annual reports, the applicant should provide similar information, labeled as Exhibit C-1, or indicate that Exhibit C-1 is not applicable and why.

C-2 **Exhibit C-2 "SEC Filings,"** provide the most recent 10-K/8-K Filings with the SEC. If applicant does not have such filings, it may submit those of its parent company. If the applicant does not have such filings, then the applicant may indicate in Exhibit C-2 whether the applicant is not required to file with the SEC and why.

C-3 **Exhibit C-3 "Financial Statements,"** provide copies of the applicant's two most recent years of audited financial statements (balance sheet, income statement, and cash flow statement). If audited financial statements are not available, provide officer-certified financial statements. If the applicant has not been in business long enough to satisfy this requirement, it shall file audited or officer-certified financial statements covering the life of the business.

C-4 **Exhibit C-4 "Financial Arrangements,"** provide copies of the applicant's current financial arrangements to conduct competitive retail natural gas service (CRNGS) as a business activity (e.g., guarantees, bank commitments, contractual arrangements, credit agreements, etc.)

C-5 **Exhibit C-5 "Forecasted Financial Statements,"** provide two years of forecasted financial statements (balance sheet, income statement, and cash flow statement) for the applicant's CRNGS operation, along with a list of assumptions, and the name, address, email address, and telephone number of the preparer.

C-6 **Exhibit C-6 "Credit Rating,"** provide a statement disclosing the applicant's current credit rating as reported by two of the following organizations: Duff & Phelps, Dun and Bradstreet Information Services, Fitch IBCA, Moody's Investors Service, Standard & Poors, or a similar organization. In instances where an applicant does not have its own credit ratings, it may substitute the credit ratings of a parent or affiliate organization, provided the applicant submits a statement signed by a principal officer of the applicant's parent or affiliate organization that guarantees the obligations of the applicant.

C-7 **Exhibit C-7 "Credit Report,"** provide a copy of the applicant's current credit report from Experion, Dun and Bradstreet, or a similar organization.

C-8 **Exhibit C-8 "Bankruptcy Information,"** provide a list and description of any reorganizations, protection from creditors, or any other form of bankruptcy filings made by the applicant, a parent or affiliate organization that guarantees the obligations of the applicant or any officer of the applicant in the current year or since applicant last filed for certification.

C-9 **Exhibit C-9 "Merger Information,"** provide a statement describing any dissolution or merger or acquisition of the applicant since applicant last filed for certification.

SECTION D – APPLICANT TECHNICAL CAPABILITY

PROVIDE THE FOLLOWING AS SEPARATE ATTACHMENTS AND LABEL AS INDICATED.

D-1 **Exhibit D-1 "Operations,"** provide a current written description of the operational nature of the applicant's business. Please include whether the applicant's operations will include the contracting of natural gas purchases for retail sales, the nomination and scheduling of retail natural gas for delivery, and the provision of retail ancillary services, as well as other services used to supply natural gas to the natural gas company city gate for retail customers.

D-2 **Exhibit D-2 "Operations Expertise,"** given the operational nature of the applicant's business, provide evidence of the applicant's current experience and technical expertise in performing such operations.

D-3 **Exhibit D-3 "Key Technical Personnel,"** provide the names, titles, email addresses, telephone numbers, and background of key personnel involved in the operational aspects of the applicant's current business.

Applicant Signature and Title _____ , President and Chief Executive Officer

Sworn and subscribed before me this 22nd **day of** March **Month** 2013 **Year**

Linda S. Sumpter
Signature of official administering oath

Linda S. Sumpter, Executive Asst
Print Name and Title

LINDA S SUMPTER NOTARY PUBLIC FULTON COUNTY, GEORGIA MY COMMISSION EXPIRES MARCH 4, 2014

My commission expires on March 4, 2014

The Public Utilities Commission of Ohio

Competitive Retail Natural Gas Service
Affidavit Form
(Version 1.07)

In the Matter of the Application of)
SouthStar Energy Services LLC)
for a Certificate or Renewal Certificate to Provide)
Competitive Retail Natural Gas Service in Ohio.)

Case No. 07 - 0378 **-GA-CRS**

County of Fulton
State of Georgia

Michael A. Braswell [Affiant], being duly sworn/affirmed, hereby states that:

(1) The information provided within the certification or certification renewal application and supporting information is complete, true, and accurate to the best knowledge of affiant.

(2) The applicant will timely file an annual report of its intrastate gross receipts and sales of hundred cubic feet of natural gas pursuant to Sections 4905.10(A), 4911.18(A), and 4929.23(B), Ohio Revised Code.

(3) The applicant will timely pay any assessment made pursuant to Section 4905.10 or Section 4911.18(A), Ohio Revised Code.

(4) Applicant will comply with all applicable rules and orders adopted by the Public Utilities Commission of Ohio pursuant to Title 49, Ohio Revised Code.

(5) Applicant will cooperate with the Public Utilities Commission of Ohio and its staff in the investigation of any consumer complaint regarding any service offered or provided by the applicant.

(6) Applicant will comply with Section 4929.21, Ohio Revised Code, regarding consent to the jurisdiction of the Ohio courts and the service of process.

(7) Applicant will inform the Public Utilities Commission of Ohio of any material change to the information supplied in the certification or certification renewal application within 30 days of such material change, including any change in contact person for regulatory or emergency purposes or contact person for Staff use in investigating customer complaints.

(8) Affiant further sayeth naught.

Affiant Signature & Title President and Chief Executive Officer

Sworn and subscribed before me this 22nd **day of** March **Month** 2013 **Year**

Signature of Officer Administering Oath

Linda S. Sumpter, Executive Ass't
Print Name and Title

LINDA S. SUMPTER NOTARY PUBLIC FULTON COUNTY, GEORGIA MY COMMISSION EXPIRES MARCH 4, 2014

My commission expires on March 4, 2014

180 East Broad Street • Columbus, OH 43215-3793 • (614) 466-3016 • www.PUCO.ohio.gov
The Public Utilities Commission of Ohio is an Equal Opportunity Employer and Service Provider

SouthStar Energy Services LLC

Exhibit A-14

Principal Officers, Directors & Partners

Name	Title	Address	Telephone Number
Michael A. Braswell	President & Chief Executive Officer	817 W. Peachtree Street, N.W. Suite 1000 Atlanta, GA 30308	(404) 685-4022
John H. Jamieson	Sr. V.P. Retail Operations	817 W. Peachtree Street, N.W. Suite 1000 Atlanta, GA 30308	(404) 685-4025
Michael P. Nieman	Sr. V.P. Commercial Operations	817 W. Peachtree Street, N.W. Suite 1000 Atlanta, GA 30308	(404) 685-4013
Robert A. Cumbie	V.P. Business Development & Strategic Planning	817 W. Peachtree Street, N.W. Suite 1000 Atlanta, GA 30308	(404) 685-4020
Joseph C. Monroe	V.P. Regulatory and Market Development	817 W. Peachtree Street, N.W. Suite 1000 Atlanta, GA 30308	(404) 685-4041

SouthStar Energy Services LLC

Exhibit A-15

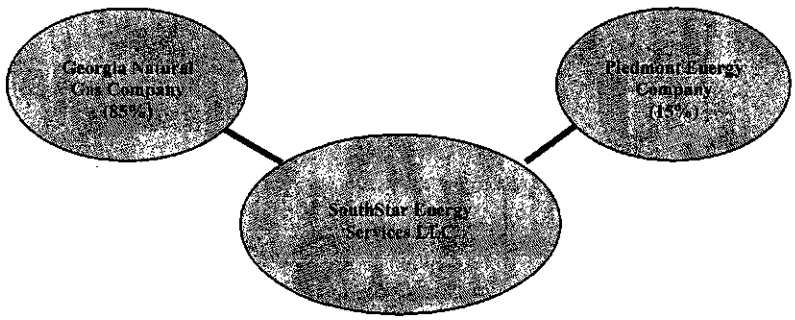
Corporate Structure

SouthStar Energy Services LLC ("SouthStar") is a Delaware limited liability company owned 85% by Georgia Natural Gas Company, a wholly-owned subsidiary of AGL Resources Inc., and 15% by Piedmont Energy Company, a wholly-owned subsidiary of Piedmont Natural Gas Company, Inc.

SouthStar markets natural gas and related services to retail customers on an unregulated basis, principally in Georgia under the trade name "Georgia Natural Gas", as well as to commercial and industrial customers in Tennessee, North Carolina, South Carolina, Alabama and Florida. Since December 2007, SouthStar has operated as a competitive retail natural gas supplier in Ohio under the trade name "Ohio Natural Gas". In October 2010, SouthStar received the approval of the New York Public Service Commission to serve residential and nonresidential natural gas customers in New York State under the trade name "New York Natural Gas." SouthStar also received the approval of the Maryland Public Service Commission in December 2010 to begin providing natural gas supplier services to residential, commercial and industrial customers in Maryland under the trade name "Maryland Energy."

AGL Resources is an Atlanta-based energy services holding company with operations in natural gas distribution, retail operations, wholesale services, midstream operations and cargo shipping. As the nation's largest natural gas-only distributor based on customer count, AGL Resources serves approximately 4.5 million utility customers through its regulated distribution subsidiaries in seven states. The company also serves approximately 1.5 million retail customers through its SouthStar Energy Services joint venture and Nicor National, which market natural gas and related home services. Other non-utility businesses include asset management for natural gas wholesale customers through Sequent Energy Management, ownership and operation of natural gas storage facilities, and ownership of Tropical Shipping, one of the largest containerized cargo carriers serving the Bahamas and Caribbean region. AGL Resources is a member of the S&P 500 Index.

Piedmont Natural Gas Company, Inc. is an energy services company primarily engaged in the distribution of natural gas to more than one million residential, commercial, industrial and power generation customers in portions of North Carolina, South Carolina and Tennessee, including 51,600 customers served by municipalities who are wholesale customers. Its subsidiaries are invested in joint venture, energy-related businesses, including SouthStar, interstate natural gas storage and intrastate natural gas transportation businesses.



SouthStar Energy Services LLC

Exhibit A-16

Company History

SouthStar was formed as a joint venture in 1998 by Piedmont Energy Company, a wholly-owned subsidiary of Piedmont Natural Gas Company, Inc., Dynegy Inc. and Georgia Natural Gas Company, a wholly-owned subsidiary of AGL Resources Inc., to market natural gas and related services to retail customers in the Southeast, principally in Georgia. Georgia Natural Gas Company purchased the entire 20% interest in SouthStar held by Dynegy, Inc. in March 2003 and an additional 15% interest held by Piedmont Energy Company in December 2009. As a result of these transactions, Georgia Natural Gas Company now owns an 85% interest in SouthStar, while Piedmont Energy Company owns the remaining 15% interest.

Today SouthStar is the largest retail marketer of natural gas in Georgia, with an average customer count around 500,000 and a market share of approximately 33%. In Georgia, SouthStar operates under the trade name "Georgia Natural Gas,"; in Ohio, SouthStar operates under the trade name "Ohio Natural Gas"; in Florida, SouthStar operates under the trade name "Florida Natural Gas"; in New York, SouthStar operates under the trade name "New York Natural Gas"; and in Maryland, SouthStar operates under the trade name "Maryland Energy." SouthStar also does business in the Carolinas under the trade name "Piedmont Energy Company."

SouthStar currently serves approximately 36,000 retail customers in Ohio and an additional 12,500 customers in Florida. SouthStar received regulatory approval in October 2010 to begin serving customers in New York and currently serves approximately 1,200 retail customers. In December 2010, SouthStar also received regulatory approval to begin serving customers in Maryland and currently serves approximately 2,400 retail customers.

SouthStar was a successful bidder in the initial Dominion East Ohio Standard Service Offer ("SSO") auction, as well as the first Vectren Energy Delivery of Ohio's SSO auction.

SouthStar Energy Services LLC

Exhibit A-17

Articles of Incorporation and Bylaws

Not applicable, as the contents of the originally filed documents have not changed since SouthStar's initial application.

SouthStar Energy Services LLC

Exhibit A-18

Secretary of State

See attached.

United States of America
State of Ohio
Office of the Secretary of State

I, Jon Husted, do hereby certify that I am the duly elected, qualified and present acting Secretary of State for the State of Ohio, and as such have custody of the records of Ohio and Foreign business entities; that said records show SOUTHSTAR ENERGY SERVICES LLC, a Delaware Limited Liability Company, Registration Number 1641383, filed on August 14, 2006, is currently in FULL FORCE AND EFFECT upon the records of this office.



Witness my hand and the seal of the Secretary of State at Columbus, Ohio this 12th day of March, A.D. 2013

Jon Husted

Ohio Secretary of State

Validation Number: V201371MBC7C9

SouthStar Energy Services LLC

Exhibit B-1

Jurisdictions of Operation

SouthStar Energy Services LLC – Alabama, Florida, Georgia, Maryland, New York, North Carolina, Ohio, South Carolina and Tennessee.

AGL Resources Inc. – Regulated distribution companies in Tennessee, Georgia (delivery service only), Florida, Virginia, New Jersey, Maryland and Illinois. Retail gas supply services in Illinois.

Piedmont Natural Gas Company, Inc. – Regulated distribution companies in North Carolina, South Carolina and Tennessee.

SouthStar Energy Services LLC

Exhibit B-2

Experience & Plans

SouthStar has operated as a retail marketer of natural gas since 1998 and currently serves approximately 500,000 residential, commercial and industrial customers. SouthStar processes and mails over 550,000 customer invoices per month, consistently exceeding the quality standards for billing accuracy set by the Georgia Public Service Commission. SouthStar manages multiple call centers for its customer contacts, complaint resolution and correspondence. In 2012, SouthStar's approximately 200 customer service representatives and back-office personnel processed approximately 1.4 million customer inquiries. SouthStar offers several variable and fixed price products to meet individual customer needs. To effectively communicate its service offerings, SouthStar publishes and issues standard terms and conditions of service to all of its customers.

Serving Ohio natural gas customers remains a key part of SouthStar's continued growth strategy, with continuous participation in the Ohio market as a retail marketer since 2007. In serving customers in Ohio, SouthStar will continue to follow the rules and regulations of the Public Utilities Commission of Ohio applicable to its business.

SouthStar Energy Services LLC

Exhibit B-3

Summary of Experience

SouthStar is the retail marketing affiliate of AGL Resources Inc. and Piedmont Natural Gas Company, Inc. – two of the Southeast's largest natural gas companies. The officers of SouthStar combined have more than 90 years of experience in the energy industry.

SouthStar manages a diversified supply portfolio consisting of more than 50 wholesale providers for physical natural gas deliveries. In 2012, SouthStar transported approximately 55 Bcf of natural gas for all of its markets. SouthStar serves approximately 500,000 residential, commercial and industrial customers.

SouthStar also offers asset management services, balancing services, consolidated billing, cost-saving research, forecasting, financial and physical hedging strategies, and purchasing and transporting for storage facilities. SouthStar has the largest deregulated market share in Georgia and is the largest natural gas marketer in the Southeast.

SouthStar Energy Services LLC

Exhibit B-4

Disclosure of Liabilities and Investigations

None.

SouthStar Energy Services LLC

Exhibit B-5

Disclosure of Consumer Protection Violations

Not applicable.

SouthStar Energy Services LLC

Exhibit B-6

Disclosure of Certification Denial, Curtailment, Suspension or Revocation

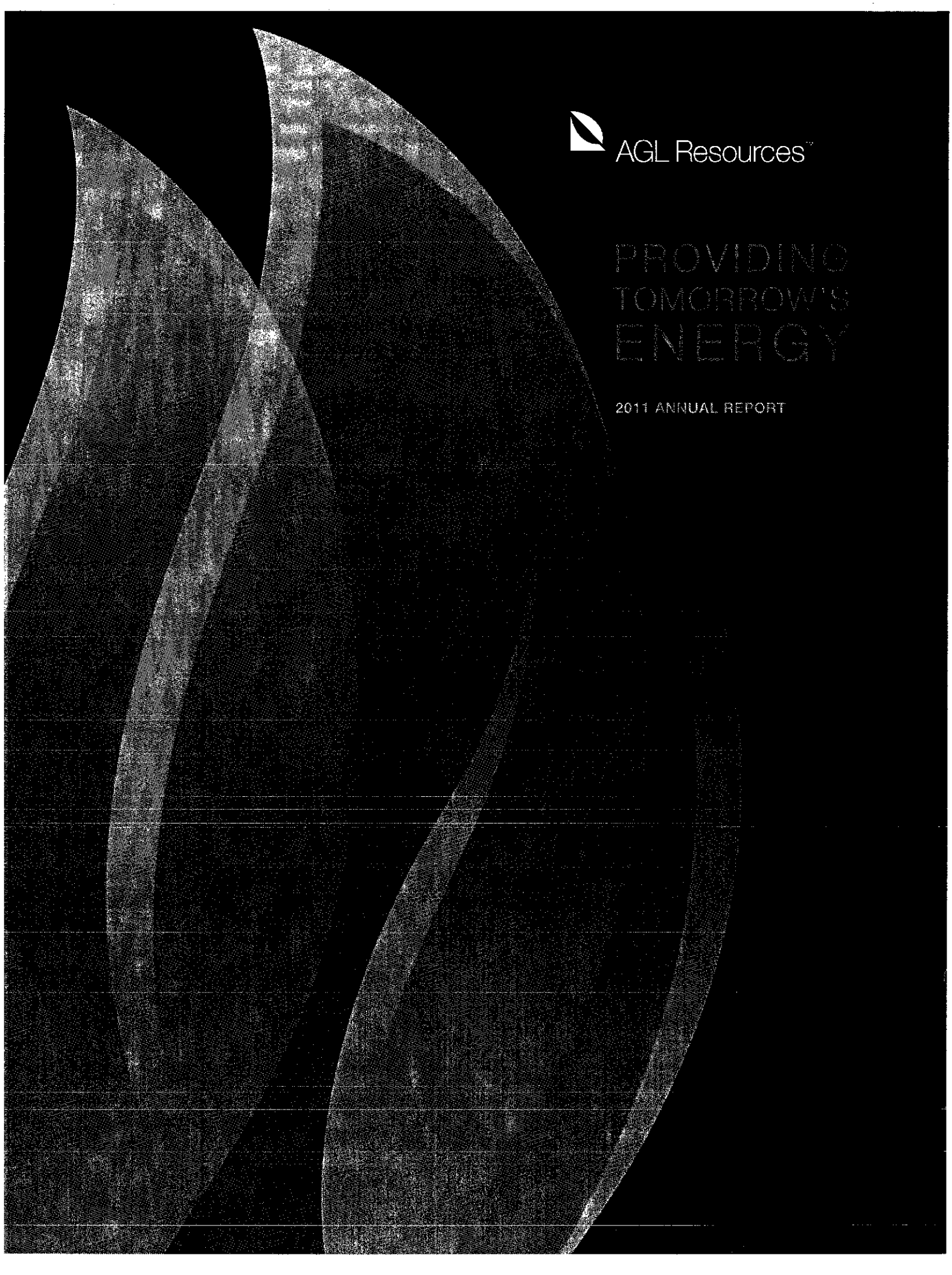
Not applicable.

SouthStar Energy Services LLC

Exhibit C-1

Annual Reports

SouthStar is a privately-held company that is not subject to SEC reporting. The two most recent annual reports of each of its member companies' parent companies are attached.

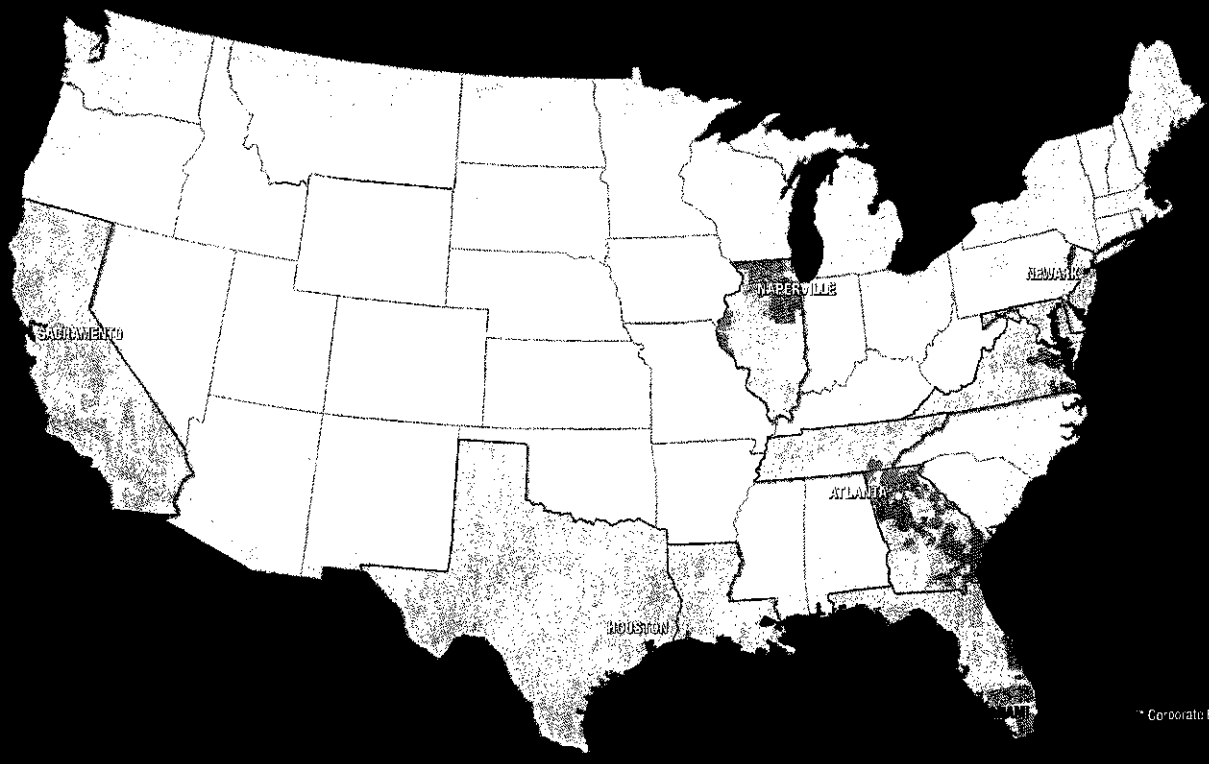


AGL Resources™

PROVIDING TOMORROW'S ENERGY

2011 ANNUAL REPORT

AGL RESOURCES AT A GLANCE

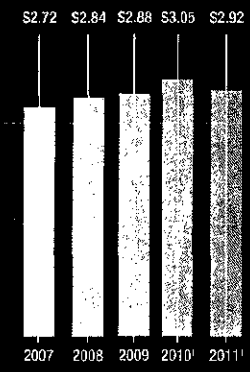


AGL Resources serves approximately 4.5 million end-use customers in seven states through its utility subsidiaries within the distribution operations segment: Nicor Gas in Illinois, Atlanta Gas Light in Georgia, Virginia Natural Gas in Virginia, Elizabethtown Gas in New Jersey, Florida City Gas in Florida, Chattanooga Gas in Tennessee and Elkton Gas in Maryland. Our retail operations segment serves more than one million retail customers and markets natural gas and related home services to end-use customers in Georgia, Illinois, Ohio, Florida and New York. 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 operations 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 Storage, currently under development in northern California. As a result of the Nicor merger, 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

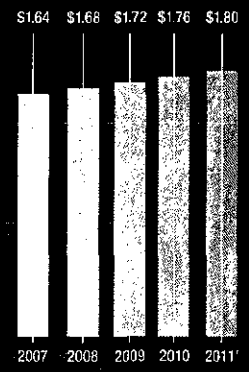
In millions, except per share amounts and market price	2011	2010	Change
Operating revenues	$ 2,338	$ 2,373	(1%)
Net income attributable to AGL Resources Inc.	$ 172	$ 234	(26%)
Earnings per common share attributable to AGL Resources Inc. common shareholders			
Basic	$ 2.14	$ 3.02	(29%)
Diluted	$ 2.12	$ 3.00	(29%)
Dividends declared per common share	$ 1.90	$ 1.76	8%
Market capitalization (year-end)	$ 4,946	$ 2,800	77%
Market price (year-end, closing)	$ 42.26	$ 35.85	18%
Total assets	$13,913	$ 7,520	85%
Total shareholder return	24%	3%	

DILUTED EARNINGS PER SHARE



(1) For a reconciliation of adjusted EPS (which excludes costs related to the Nicor merger) to GAAP EPS, see our non-GAAP reconciliation section included with this report.

INDICATED ANNUAL DIVIDEND PER SHARE



(1) Indicated 2011 dividend rate. As a result of the merger with Nicor, 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 2011 dividend of $1.90.

TO OUR SHAREHOLDERS

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



In 2011 we extended our track record of solid returns for our shareholders with a total shareholder return for the year of 24%. We accomplished this by remaining focused on the fundamentals of our business: the safe and efficient operation of our natural gas distribution systems, excellent customer service, effective expense control and maintaining a solid balance sheet.

AGL RESOURCES AND NICOR COMBINATION

While delivering on these important principles, we also worked diligently throughout the year to complete our acquisition of Nicor Inc. on December 9, 2011, effectively doubling the size of our regulated asset and customer base. Bringing our two industry-leading utilities together creates the largest natural gas-only distribution utility in the United States, serving 4.5 million customers across seven states. The combination of our non-utility businesses will enable us to leverage our joint experience in retail and wholesale marketing, asset optimization and natural gas storage. We've also added Nicor's cargo shipping business to our complement. Employees of both companies spent countless hours ensuring that we were ready for smooth operation on the first day following the close of the transaction, and their efforts led to a seamless transition.

In deploying our shared services model, we have identified numerous efficiencies across both companies, which we expect will translate into enhanced value for both our shareholders and customers.

After closing the transaction, AGL Resources adopted the Nicor ticker symbol, and our stock now trades under that symbol – GAS – on the New York Stock Exchange. AGL Resources also became part of the S&P 500 index for the first time. We are proud of our new enterprise and look forward to integrating all aspects of our business as 2012 progresses.

FINANCIAL RESULTS

In 2011, AGL Resources achieved diluted earnings per share (EPS) of $2.12 on a GAAP basis. Excluding $64 million in after-tax costs related to the Nicor merger, diluted EPS were $2.92 on a adjusted basis.[1] Our 2011 cash dividend payments increased 2.2% over 2010, with an indicated annual dividend rate of $1.80 per share. On February 7, 2012, our Board of Directors approved another 2.2% increase in the quarterly dividend, putting us on track for a $1.84 per share dividend rate in 2012. Importantly, we expect to maintain our policies of increasing dividends in line with earnings and maintaining a dividend payout ratio similar to our industry peers.

We remain focused on maintaining a solid balance sheet and strong, investment-grade credit ratings. During 2011 we completed more than $2 billion in financing activity, including

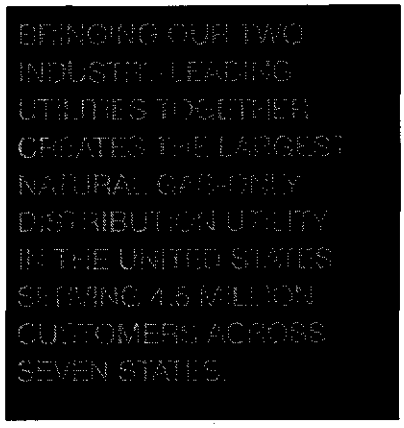
[1] For a reconciliation of adjusted EPS (which excludes costs related to the Nicor merger) to GAAP EPS, see our non-GAAP reconciliation section included with this report.

the portion required to fund the acquisition of Nicor. We were able to capitalize on the historically low interest-rate environment during the year to achieve weighted-average long-term debt costs that were meaningfully better than our expectations, and as a result, lowered the corporation's overall long-term cost of debt to 5.3%, down from 6.0% at the end of 2010.

SIGNIFICANT ACHIEVEMENTS

Distribution Operations

AGL Resources posted strong earnings growth in its distribution operations segment in 2011, which includes its operation of six regulated utilities (excluding Nicor for 2011) in Georgia, Virginia, New Jersey, Tennessee, Florida and Maryland. We continued to provide safe, reliable service to our utility customers. During 2011, Atlanta Gas Light hired over 100 additional employees and invested in technology, equipment and fleet for new customer service and safety-oriented programs that were approved and funded in the company's 2010 rate case. We completed the installation of Automated Meter Reading (AMR) devices at several of our utilities ahead of schedule and under budget. In addition, AGL Resources remained committed to infrastructure improvement and pipeline replacement, with dedicated programs in place in both Georgia and New Jersey. In 2011, we replaced approximately 100 miles of pipeline in Georgia, bringing the total to more than 2,500 miles of pipe replaced since 1998. While the safety and reliability of our natural gas systems is the primary aim of these infrastructure programs, they have also helped create new jobs across our jurisdictions.



In December 2011, the Virginia State Corporation Commission accepted the terms of settlement reached by Virginia Natural Gas (VNG) and several parties resolving the company's rate case petition. The agreement results in recovery of approximately $16 million in additional cash annually, mostly related to the Hampton Roads Crossing pipeline project cost. The outcome of the case is only modestly additive to earnings as VNG was previously collecting AFUDC (allowance for funds used during construction) and carrying costs on the project. The new rates were based on a 10% return on equity.

Retail Operations

Our retail operations, consisting primarily of SouthStar Energy Services, achieved solid results again in 2011. In Georgia, SouthStar's primary market, we maintained our leading position, serving 33% of the market. While competition for customers in Georgia remains robust, our team is focused on new marketing initiatives and margin enhancing activities to sustain the segment's stable and strong performance. SouthStar continues its efforts to expand in jurisdictions beyond Georgia, and with the Nicor merger completed we look forward to combining and leveraging both companies' retail experience, which will include natural gas commodity marketing as well as warranty products and related services.

Wholesale Services

While the low natural gas prices that persisted for much of the year certainly translated into lower commodity costs for our distribution and retail customers, the low volatility environment created challenges for our wholesale business, Sequent Energy Management, which generally benefits from seasonal and location-based price spreads. In fact, 2011 was one of the most difficult years Sequent has faced since its inception in 2001. Changing pipeline transportation dynamics, such as a wave of new shale gas entering the market, and extremely low natural gas storage spreads meant fewer opportunities to optimize our diverse portfolio of assets. These challenges coupled with fourth quarter 2011 weather being significantly warmer than normal continued to put pressure on earnings in this business.

Though its contribution to consolidated earnings was muted in 2011 relative to prior years, this business segment remains highly important to AGL Resources. Sequent has asset management agreements (AMAs) in place with all of our regulated utilities with the exception of Nicor Gas. Over the past 11 years, Sequent has effectively optimized our regulated utility assets resulting in savings to our customers and value to our utilities of over $190 million. As we move ahead in 2012, our primary objectives at Sequent are to continue delivering value to our customers and to Sequent via the AMAs, to maintain a strong focus on cost control, and to enhance our service offerings to third parties while efficiently utilizing capital and maintaining rigorous risk controls.

Midstream Operations

We continue to make progress on construction and permitting at our natural gas salt dome storage facilities. At Golden Triangle Storage in Texas, we completed our first full year of operation at Cavern 1 and expect to complete construction of Cavern 2 in the first half of 2012. Once complete, this facility will operate a total of 13 Bcf of high deliverability storage capacity. In January we received permission from the Federal Energy Regulatory Commission to add Caverns 3 and 4 at Golden Triangle, which would increase working capacity by another 16 Bcf. At Jefferson Island Storage and Hub in Louisiana we continue operating 7 Bcf of capacity, and are working to secure permits from the Louisiana Department of Natural Resources to expand the facility by 12 Bcf, should market

conditions indicate that expansion is prudent. Obtaining the permits at both Golden Triangle and Jefferson Island enhances the value of our storage portfolio and provides us with the necessary approvals to proceed with construction as market conditions warrant. With the completion of the Nicor merger, we also added the Central Valley storage facility in California to our storage portfolio. This is an 11 Bcf facility which is expected to be in service in the first half of 2012. As with our wholesale services business, the storage market remains challenged due to low natural gas price volatility, but we plan to complete the projects listed above, taking a long-term view of increased natural gas demand brought about by eventual global economic recovery.

INDUSTRY UPDATE - NATURAL GAS FUNDAMENTALS

As I mentioned, the discovery and production of shale gas in North America over the past decade is rapidly changing the natural gas landscape. Production from shale formations was virtually non-existent just a few years ago and now represents approximately one-third of natural gas production in the U.S. In fact, since 2008 the production of shale gas has increased four fold. This bodes quite well for our industry and for customers of AGL Resources. While we may have to make adjustments in parts of our business to accommodate this new paradigm, over the long-term we should expect new users of natural gas as prices remain favorable relative to other energy sources such as crude oil, petroleum and even coal.

OVER THE LONG-TERM WE SHOULD EXPECT NEW USERS OF NATURAL GAS AS PRICES REMAIN FAVORABLE TO OTHER ENERGY SOURCES SUCH AS CRUDE OIL, PETROLEUM AND EVEN COAL.

New technologies are rapidly emerging that should make compressed natural gas (CNG) and liquefied natural gas (LNG) more viable and more available for fueling vehicles. Companies like ours are working with manufacturers, fleet vehicle owners, government agencies and many others to foster the use of natural gas as a cleaner burning, lower cost alternative to gasoline. For example, in 2011 Georgia utility regulators approved a plan developed by Atlanta Gas Light that incents the private sector to invest in CNG vehicle fueling stations. We also purchased a small LNG facility in Trussville, Alabama that sells LNG in the wholesale market to buyers who then deliver the fuel to end-users such as trucking fleet operators. While these projects are small contributors to our business today, they demonstrate AGL Resources' commitment to furthering the use of a clean-burning, abundant domestic resource.

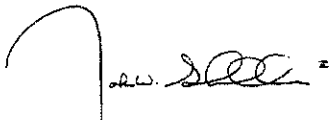
PRIORITIES FOR 2012

Our overall business strategy for 2012 is consistent with the direction we have taken the company over the past decade. We will remain focused on maintaining a roughly 70% / 30% mix of utility / non-utility earnings, strengthening our industry-leading distribution operations segment, integrating our operations with Nicor across all business segments and delivering the safe, reliable service our customers expect. Several of our specific business objectives are detailed below:

- **Distribution operations:** Make necessary capital investments to enhance and maintain the safety and reliability of our distribution systems, while minimizing regulatory lag; remain a low-cost leader within the industry.
- **Retail operations:** Maintain market share in Georgia and Illinois while expanding further into new territories such as Ohio and Florida; leverage experience across SouthStar and Nicor's retail businesses.
- **Wholesale services:** Renew affiliated and non-affiliated asset management agreements and add new asset management, producer services and gas-fired power generation; continually enhance risk management, credit management and overall controls.
- **Midstream operations:** Complete construction of Golden Triangle Cavern 2 and Central Valley and execute contracts for newly available capacity; reduce commercial and project development costs in response to low price volatility environment.
- **Cargo shipping:** Expand market share in key service areas while providing quality total transportation and logistics solutions for our customers shipping into, through and from the Caribbean and Bahamas regions; prudently deploy capital investment to ensure maximum service safety and reliability; diligently manage operating costs.

From all of the employees at AGL Resources, we thank you for your interest in and ownership of our company's stock. At all levels of the company we remain focused on creating value for our shareholders and maintaining our track record of strong shareholder returns.

Sincerely,



John W. Somerhalder II
Chairman, President and Chief Executive Officer
February 29, 2012

BOARD OF DIRECTORS



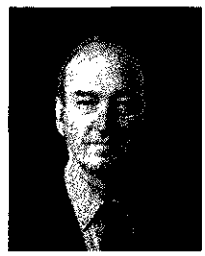
Sandra N. Bane [1,2]
Retired Audit Partner, KPMG, LLP
Director since 2008



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



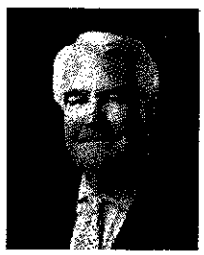
Charles R. Crisp [2,4]
Retired CEO and Director of Coral Energy, a subsidiary of Shell Oil Company
Director since 2003



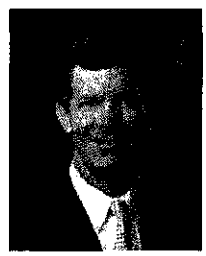
Brenda J. Gaines [1,5]
Retired President and CEO of Diners Club North America, a division of Citigroup
Director since 2011



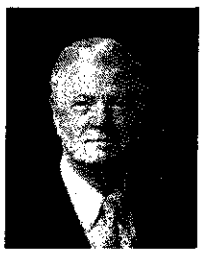
Arthur E. Johnson [3*,4,5]
Lead Director of the Board of Directors of AGL Resources and Retired Senior Vice President, Lockheed Martin Corporation
Director since 2002



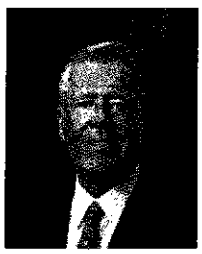
Wyck A. Knox, Jr. [1,5]
Retired Partner in, Kilpatrick, Townsend & Stockton, LLP
Director since 1998



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 [4]
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

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, 2011

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 or 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 voting and non-voting common equity held by non affiliates of the registrant, computed by reference to the price at which the registrant's common stock was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter, was $3,193,375,611.

The number of shares of the registrant's common stock outstanding as of February 15, 2012 was 117,099,662.

Documents incorporated by reference:

Portions of the Proxy Statement for the 2012 Annual Meeting of Shareholders ("Proxy Statement") to be held May 1, 2012, are incorporated by reference in Part III.

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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

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 agency that regulates utilities in California

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 each of which we evaluate on a consolidated level. As an indicator of our operating performance, EBIT should not be considered an alternative to, or more meaningful than, earnings before income taxes, or net income attributable to AGL Resources Inc. as determined in accordance with GAAP

ERC Environmental remediation costs associated with our distribution operations segment which are generally recoverable through rate mechanisms

FASB Financial Accounting Standards Board

FERC Federal Energy Regulatory Commission

Fitch Fitch Ratings

Florida Commission Florida Public Service Commission, the state regulatory agency for Florida City Gas

GAAP Accounting principles generally accepted in the United States of America

Georgia Commission Georgia Public Service Commission, the state regulatory agency for Atlanta Gas Light

Georgia Natural Gas The name under which SouthStar does business in Georgia

Golden Triangle Storage Golden Triangle Storage, Inc.

Hampton Roads Virginia Natural Gas' pipeline project which connects its northern and southern pipelines

Heating Degree Days A measure of the effects of weather on our businesses, calculated when the average daily temperatures are less than 65 degrees Fahrenheit

Heating Season The period from November 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

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 – an acquisition completed in November 2004

NYMEX New York Mercantile Exchange, Inc.

OCI Other comprehensive income

Operating margin A non-GAAP measure of income, calculated as operating revenues minus cost of goods sold, that excludes operation and maintenance expense, depreciation and amortization, taxes other than income taxes, and gains or losses on the sale of our assets; these items are included in our calculation of operating income as reflected in our Consolidated Statements of Income. Operating margin should not be considered an alternative to, or more meaningful than, operating income as determined in accordance with GAAP

OTC Over-the-counter

Pad gas Volumes of non-working natural gas used to maintain the operational integrity of the natural gas storage facility

PBR Performance-based rate, a regulatory plan that provided economic incentives based on natural gas cost performance

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

Sawgrass Storage Sawgrass Storage, LLC

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 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 may also make verbal statements to analysts, investors, regulators, the media and others that are forward-looking.

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

Such events, risks and uncertainties include, but are not limited to, changes in price, supply and demand for natural gas and related products; the impact of changes in state and federal legislation and regulation including any changes related to climate change; actions taken by government agencies on rates and other matters; concentration of credit risk; utility and energy industry consolidation; the impact on cost and timeliness of construction projects by government and other approvals, development project delays, adequacy of supply of diversified vendors, unexpected change in project costs, including the cost of funds to finance these projects; limits on pipeline capacity; the impact of acquisitions and divestitures; our ability to integrate successfully operations that we have or may acquire or develop in the future, including those of Nicor, and realize cost savings and any other synergies related to any such integration, or the risk that any such integration could be more difficult, time-consuming or costly than expected; uncertainty of our expected financial performance following the recent completion of the Nicor merger; disruption from the recent Nicor merger making it more difficult to maintain relationships with customers, employees or suppliers; direct or indirect effects on our business, financial condition or liquidity resulting from any change in our credit ratings resulting from the recent merger with Nicor or otherwise or any change in the credit ratings of our counterparties or competitors; interest rate fluctuations; financial market conditions, including recent disruptions in the capital markets and lending environment and the current economic downturn; and general economic conditions; uncertainties about environmental issues and the related impact of such issues; the impact of changes in weather, including climate change, on the temperature-sensitive portions of our business; the impact of natural disasters such as hurricanes on the supply and price of natural gas; acts of war or terrorism; the outcome of litigation; and other factors discussed elsewhere herein and in our 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 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," the "company" and "AGL Resources" are intended to mean consolidated AGL Resources Inc. and its 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 was organized and incorporated in 1995 under the laws of the State of Georgia.

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. We are now the nation's largest natural gas distribution company based on customer count. In accordance with the Merger Agreement, each share of Nicor common stock outstanding at the Effective Time (as defined in the Merger Agreement), other than shares to be cancelled, and Dissenting Shares (as defined in the Merger Agreement), was converted into the right to receive consideration consisting of (i) $21.20 in cash and (ii) 0.8382 shares of AGL Resources common stock. 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. The total purchase consideration of $2.5 billion paid to Nicor shareholders was primarily based on the number of Nicor shares outstanding on December 9, 2011, and the volume-weighted average price of AGL Resources common stock on December 8, 2011.

In connection with the Nicor merger, the headquarters of our distribution operations segment moved to Naperville, Illinois during December 2011 and we agreed not to initiate a rate proceeding that would increase our base rates effective prior to December 7, 2014. We have committed to maintain 2,070 full-time equivalent employees involved in the operation of Nicor Gas for a period of three years and maintain the personnel numbers in specific areas of safety oversight of the Nicor Gas system for a period of at least five years. Additionally, we are required to maintain the same level of corporate philanthropy within the communities that Nicor Gas serves.

See the following discussions for more information on the impacts of the Nicor merger on our business. Additionally, see the Executive Summary within Management's Discussion and Analysis of Financial Condition and Results of Operations, as well as Note 3 to our consolidated financial statements under Item 8 herein, for additional information on the merger. During 2011, we recorded approximately $68 million ($55 million net of tax) of transaction expenses associated with the merger with Nicor. These costs are expensed as incurred. The effects of Nicor's results of operations and financial condition on our 2011 results include activity from December 10, 2011 through December 31, 2011.

Nature of Our Business

We are an energy services holding company whose principal 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, including, as a result of the Nicor merger, Nicor Gas. At December 31, 2011, our seven utilities served approximately 4.5 million end-use customers.

In addition to our primary business of the distribution of natural gas, we are involved in several related and complementary businesses. 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, Ohio, Florida and New York. Our wholesale services segment provides natural gas storage 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.

As a result of the Nicor merger 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.

In connection with the completion of the Nicor merger on December 9, 2011, we revised our operating segments to be 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.

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[1]	Illinois	2,188	34,000
Atlanta Gas Light	Georgia	1,541	32,250
Virginia Natural Gas	Virginia	278	5,500
Elizabethtown Gas	New Jersey	276	3,150
Florida City Gas	Florida	103	3,450
Chattanooga Gas	Tennessee	62	1,600
Elkton Gas	Maryland	6	100
Total		4,454	80,050

[1] Customers as of December 31, 2011.

The focus on the design of our distribution operations is the delivery of safe and reliable natural gas to our end-users. In integrating Nicor Gas into our existing distribution operations, we plan to focus on the standardization of operational processes along with continuing to focus on delivering superior customer service.

Competition and Customer Demand

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

Competition for space heating and general household and small commercial energy needs generally occurs at the initial installation phase when the customer or builder makes decisions as to which types of equipment to install. Customers generally continue to use the chosen energy source for the life of the equipment. Customer demand for natural gas could be affected by numerous factors, including:

- changes in the availability or price of natural gas and other forms of energy
- general economic conditions
- energy conservation
- legislation and regulations
- the capability to convert from natural gas to alternative fuels
- weather
- new commercial construction and
- new housing starts.

Over the last two years there has been some improvement in the economic conditions within the areas we serve. However, there continue to be high rates of unemployment and depressed housing markets with high inventories, significantly reduced new home construction and a slow-down in new commercial development. As a result, we have experienced slight customer losses in our distribution operations segment. Excluding Nicor Gas, our year-over-year consolidated utility customer gain rate was 0.1% in 2011, compared to a loss rate of (0.1)% for 2010. We anticipate overall competition and customer trends in 2012 to be similar to our 2011 results. For the full year 2011 the customer count of Nicor Gas increased by 0.4% compared to 0.2% for 2010.

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

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 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. Additionally, we provide rebates and other incentives to our Nicor Gas customers through similar energy efficiency plans.

Sources of Natural Gas Supply

We purchase natural gas supplies in the open market by contracting with producers and marketers. We also purchase 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, with proceeds 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 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.

Utility Regulation and Rate Design

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

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
- 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 mechanisms at some of our utilities which limit our exposure to weather changes within typical ranges in the 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 riders, which vary by utility but allow us to recover certain costs such as 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	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 2011 return on rate base[2]	N/A	8.33%	8.15%	8.84%	5.74%	8.43%
Authorized return on equity[1]	10.17%	10.75%	10.00%	10.30%	11.25%	10.05%
Estimated 2011 return on equity[2]	N/A	11.20%	11.97%	12.81%	8.53%	12.24%
Authorized rate base % of equity[1]	51.1%	51.0%	45.4%	47.9%	36.8%	46.1%
Rate base included in 2011 return on equity (in millions)[2]	$1,485	$1,317	$516	$476	$163	$92
Weather normalization[3]			✔	✔		✔
Decoupled or straight-fixed variable rates[4]		✔				✔
Regulatory infrastructure program rates[5]		✔		✔		
Bad debt rider[6]	✔					
Synergy sharing policy[7]		✔				
Last decision on change in rates[8]	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, 2011.

[2] Estimates based on principles consistent with utility ratemaking in each jurisdiction.

[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.

[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. The decoupled rate design for Virginia Natural Gas expired in December 2011.

[5] Includes programs that update or expand our distribution systems and liquefied natural gas facilities.

[6] Involves the recovery (or refund) of the amount of bad debt expense over (or under) an established benchmark expense.

[7] Involves the recovery of 50% of net synergy savings achieved on future acquisitions.

[8] In connection with the Nicor merger, we agreed not to initiate a rate proceeding that would increase the base rates for Nicor Gas effective prior to December 9, 2014.

Recent Regulatory Actions

Nicor Gas In May 2011, the Illinois Commission approved an energy efficiency plan for Nicor Gas pursuant to an Illinois law that requires local gas distribution utilities to establish plans to achieve specified energy savings goals and provides utilities with a rider to collect the costs from customers. Under its approved plan, we estimate that Nicor Gas would bill approximately $155 million to customers under the rider, over a three year period which commenced June 1, 2011, to fund the costs of various energy savings programs identified in the filing. This new energy efficiency plan rider replaced the rider previously in effect. The costs under the rider are subject to annual review by the Illinois Commission.

On July 1, 2009, Nicor Gas filed a petition seeking re-approval from the Illinois Commission of the operating agreement that governs many inter-company transactions between Nicor Gas and its affiliates. The petition was filed pursuant to a requirement contained in the Illinois Commission order approving Nicor Gas's most recent general rate increase and requested that the operating agreement be re-approved without change. A number of parties intervened in the proceeding (the "operating agreement proceeding") and sought modifications on a prospective basis to the operating agreement. Among the proposals were several by the Illinois Commission Staff and intervenors that would preclude Nicor Gas from continuing to provide certain services to support warranty products that are sold by Nicor Services. Specifically, Nicor Services had used Nicor Gas personnel to assist in some sales solicitation for these warranty products. The Illinois Commission was required to evaluate future transactions between Nicor Gas and its affiliates in connection with the joint application of AGL Resources, Nicor and Nicor Gas for approval of the merger of AGL Resources and Nicor (the "merger proceeding"). The Illinois Commission Administrative Law Judge assigned to the merger proceeding decided to address the matters raised in the operating agreement proceeding in the merger proceeding. As a result, Nicor Gas is no longer permitted to use its call center personnel to solicit its affiliates' products, most notably the warranty products. This is not expected to have a material impact on our results of operations, cash flows and financial condition.

On January 1, 2000, Nicor Gas instituted a PBR plan for natural gas costs. 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. The PBR plan was terminated effective January 1, 2003. The PBR plan is currently under review by the Illinois Commission as there are allegations that Nicor Gas acted improperly in connection with the PBR plan. In February 2012, we committed to a stipulated resolution of issues with the Illinois Commission, which includes crediting Nicor Gas customers $64 million, but does not constitute an admission of fault. The stipulated resolution is subject to review and approval by the Illinois Commission. The Citizens Utility Board and the Illinois Attorney General's Office are not parties to this stipulated resolution and continue to pursue their claims in this proceeding. Evidentiary

hearings on this matter are scheduled to begin on February 28, 2012. We do not expect the stipulated resolution to affect our 2011 or 2012 Consolidated Statements of Income, as the $64 million proposed credit is consistent with the estimated liability we recorded for this matter as part of our accounting for the merger with Nicor. For more information on the PBR plan see Note 11 to our consolidated financial statements under Item 8 herein.

On February 2, 2010, the Illinois Commission approved Nicor Gas' previously filed bad debt rider. This rider provides for the recovery from (or credit to) Nicor Gas customers of the difference between Nicor Gas' actual bad debt experience on an annual basis and the $63 million benchmark bad debt expense included in its base rates for the respective year. Costs incurred for bad debt expense are subject to annual review by the Illinois Commission.

Virginia Natural Gas On December 20, 2011, the Virginia Commission approved an annual increase of $11 million in base rate revenues and established an authorized return on equity of 10% for Virginia Natural Gas with an overall return on rate base set at 7.38%. Additionally, $3.1 million of costs previously recovered through base rates will now be recovered through the company's gas cost recovery rate. Customer's bills will be credited to refund the difference between the final approved rates and an interim rate increase, which began with usage on and after October 1, 2011. The new rate is expected to increase the average residential customer's monthly bill by less than $3.50 per month depending on usage.

Environmental Remediation Costs

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. The following table provides more information on the costs related to remediation of our former MGP operating sites.

In millions	Cost estimate range [1]	Amount recorded	Expected costs over next twelve months
Illinois	$134 – $216	$134	$19
Georgia and Florida	42 – 98	58	7
New Jersey	124 – 174	124	9
North Carolina	10 – 16	11	2
Total	$310 – $504	$327	$37

[1] Our ERC liabilities are customarily reported estimates of future remediation costs for our former operating sites that are contaminated based on probabilistic models of potential costs and on an undiscounted basis. However, we have not yet performed these probabilistic models for all of our sites in Illinois, which will be completed in 2012.

As we continue to conduct the actual remediation and enter into cleanup contracts, we are increasingly able to provide conventional engineering estimates of the likely costs of many elements of the remediation program. These estimates contain various engineering uncertainties, and we regularly attempt to refine and update these engineering estimates. These costs are primarily recovered through rate riders.

See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations - Critical Accounting Estimates", for additional information about our environmental remediation liabilities. Also see 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 at 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 2012 are discussed in 'Liquidity and Capital Resources' under the caption 'Cash Flows from Financing Activities'.

Dollars in millions	Utility	Expenditures in 2011	Expenditures to date	Miles of pipe replaced	Year project began	Anticipated year of completion
Pipeline replacement program	Atlanta Gas Light	$ 70	$568	2,531	1998	2013
Integrated System Reinforcement Program	Atlanta Gas Light	89	141	n/a	2009	2012
Integrated Customer Growth Program	Atlanta Gas Light	7	12	n/a	2010	2012
Enhanced infrastructure program	Elizabethtown Gas	22	90	88	2009	2012
Total		$188	$811	2,619		

Atlanta Gas Light Our STRIDE program is comprised of the ongoing pipeline replacement program, the Integrated System Reinforcement Program (i-SRP), and Integrated Customer Growth Program (i-CGP). The purpose of the i-SRP program under STRIDE is to upgrade our distribution system and liquefied natural gas facilities in Georgia, improve our system reliability and operational flexibility, and create a platform to meet long-term forecasted growth. Our 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. Under STRIDE, we are required 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.

Virginia Natural Gas In January 2012 Virginia Natural Gas filed an accelerated infrastructure replacement program with the Virginia Commission. The program was filed pursuant to a Virginia statute that provides a regulatory cost recovery mechanism to recover the costs associated with certain infrastructure replacement programs. Our proposed program is for a five-year period and includes a maximum allowance for capital expenditure of $25 million per year, not to exceed $105 million in total over the five-year period. The Virginia Commission has six months to review and render a decision on this proposed program.

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. We expect to file for an extension of the program in 2012.

Asset Management Agreements

Some of our utilities have entered into asset management agreements with Sequent, our affiliate. These agreements are designed to efficiently manage storage and transportation assets belonging to our utilities, including the purchase and sale of natural gas as well as excess transportation and storage capacity that may not be needed on a daily basis to meet system requirements. The agreements have either annual minimum guarantees within a profit sharing structure, a profit sharing structure without any annual minimum guarantee, or a fixed fee. Under the various types of agreements, Sequent made payments of $32 million in 2011. Our utilities began entering into these agreements with Sequent in 2001. From 2001 through 2011 Sequent has made sharing payments under these agreements totaling $192 million, which has reduced customers' bills at all of our utilities except Atlanta Gas Light. For Atlanta Gas Light these payments have been made to the Universal Service Fund controlled by the Georgia Commission and utilized for infrastructure improvements and to fund heating assistance programs. The following table provides payments made by Sequent to our utilities under these agreements during the last three years.

	Total amount received			
In millions	**2011**	2010	2009	Expiration Date
Atlanta Gas Light	**$ 9**	$ 4	$16	March 2012
Virginia Natural Gas	**9**	5	7	March 2016
Elizabethtown Gas	**9**	10	11	March 2014
Florida City Gas	**2**	1	1	March 2013
Chattanooga Gas	**3**	4	4	March 2014
Total	**$32**	$24	$39	

On March 30, 2011, the New Jersey BPU authorized the renewal of the asset management agreement between Elizabethtown Gas and Sequent. The renewed agreement requires Sequent to pay minimum annual fees of $5 million to Elizabethtown Gas and includes overall margin sharing levels of 70% to Elizabethtown Gas and 30% to Sequent. In October 2011, the Virginia Commission authorized the renewal of the asset management agreement between Virginia Natural Gas and Sequent. The minimum and overall sharing levels of the renewed agreement are consistent with the prior agreement.

Retail Operations

The companies in our retail operations segment market natural gas and related home services, such as appliance repair and line protection plans to customers primarily in our utility service areas, but also in areas outside of our utility service areas. This segment also offers products that provide product protection and comfort services and natural gas price risk and utility bill management

services. These companies include SouthStar, Nicor Advanced Energy, Nicor Solutions and Nicor Services. Nicor Solutions, Nicor Services and Nicor Advanced Energy joined our business on December 9, 2011 as part of the Nicor merger and are wholly owned businesses.

Our retail operations businesses, including SouthStar, Nicor Advanced Energy and Nicor Solutions, 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 also 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 our energy solutions businesses to maintain competitive retail prices and operating margin. Through hedging transactions, we manage exposures arising from changing commodity prices by using natural gas storage transactions to capture operating margin from natural gas pricing differences that occur over time.

SouthStar, 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 in Ohio, Florida and New York. We have no contractual rights to acquire Piedmont's remaining 15% ownership interests.

SouthStar is governed by an executive committee, which is comprised of six members, three representatives from AGL Resources and three 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 - Commodity 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 warranty protection solutions to customers through Nicor Services. Such services include a gas line repair plan and a heating, ventilation, and air conditioning repair and maintenance plan, whereby we, in return for a predetermined monthly amount collected from customers, provide repair and maintenance per the contracted terms. In addition, we also provide customer move connection services for utilities. Our retail operations businesses primarily provide warranty protection solutions to customers in Illinois and Ohio under the Nicor National brand.

Competition Our retail operations business competes with other energy marketers to provide natural gas and related services to customers in Georgia, Illinois, Ohio, New York and the Southeast. In the Georgia market, SouthStar operates as Georgia Natural Gas and is the largest of eleven Marketers, with average customers of approximately 495,000 over the last three years and market share of approximately 33%.

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

In addition, similar to our natural gas utilities, 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. Natural gas price volatility in the wholesale natural gas commodity market has also contributed to an increase in competition for residential and commercial customers. We continue to use a variety of targeted marketing programs to attract new customers and to retain existing customers. In October 2011, Georgia Natural Gas was named the exclusive natural gas partner for the Delta Air Lines Inc. Delta SkyMiles Program in Georgia. This is a long-term partnership and we expect it will help retain current customers as well as attract new customers from other Marketers in Georgia.

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 consists of our wholly owned subsidiaries Sequent, Nicor Enerchange 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 manage Nicor Solutions' and Nicor Advanced Energy's product risks, including the purchase of natural gas supplies. Compass, which we acquired in 2007, 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 also 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 the opportunities arise in the Gulf Coast, Eastern, Midwestern and Western sections of the United States and Canada. These asset optimization opportunities focus on capturing the value from idle or underutilized assets, typically by participating in transactions to take advantage of volatility in pricing differences between varying geographic locations and time horizons (location and seasonal spreads) within the natural gas supply, storage and transportation markets to generate earnings. 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 further continue to broaden our market presence in sections of the United States and Canada where our portfolio of contracted storage and transportation assets provided us a competitive advantage, as well as continue our pursuit of additional opportunities with power generation companies located in the areas of the country 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 nonaffiliated utilities, municipal utilities, power generators and large industrial customers. These customers, due to seasonal demand or levels of activity, may have contracts for transportation and storage capacity which exceed their actual requirements. 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 the customers or pay them a fixed amount.

Transportation Transactions We enter into contracts for natural gas transportation capacity and participate in 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 our positions and 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.

Producer Services Our producer services activities focus on aggregating natural gas supply primarily from various small and medium-sized producers located throughout the natural gas production areas of the United States. We provide producers with certain logistical and risk management services that offer them attractive options to move their supply into the pipeline grid.

Park and Loan Transactions We routinely enter into park and loan transactions with various pipelines and storage facilities, which allows 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 Statement 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 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 the customer. 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, 2011, we had $269 million of natural gas stored underground inventory within our Consolidated Statement of Financial Position, representing 78 Bcf at an overall WACOG of $3.44.

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 and storage 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 and use 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 locked-in operating revenue to be realized at the time the physical gas is withdrawn from storage and sold and the derivative instrument used to economically hedge natural gas price risk on that physical storage is settled. Second is the GAAP reported value both in periods prior to and in the period of physical withdrawal and sale of inventory. The GAAP amount is affected by the process of accounting for the financial hedging instruments in interim periods at fair value between the period when the natural gas is injected into storage and when it is ultimately withdrawn and the derivative instruments are settled. The change in the fair value of the hedging instruments is recognized in earnings in the period of change and is recorded as unrealized gains or losses. The actual value, less any interim recognition of gains or losses on hedges and adjustments for LOCOM, is realized when the natural gas is delivered to its ultimate customer.

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 lower of average cost or current market 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 have a significant impact on our customer rates, our long-term competitive position against other energy sources and the ability of our wholesale services segment to capture value from location and seasonal spreads. During 2008 and 2009, daily Henry Hub spot market prices for natural gas in the United States were extremely volatile. However, during 2010 and 2011, the volatility of natural gas prices 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 hurricane seasons, 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 working to reposition Sequent's business model with respect to fixed costs and the types of contracts pursued and executed.

Sequent's expected natural gas withdrawals from physical salt-dome and reservoir storage are presented in the following table along with the operating revenues expected at the time of withdrawal. Sequent's expected operating revenues are net of the estimated impact of profit sharing under our asset management agreements and reflect the amounts that are realizable in future periods based on the inventory withdrawal schedule and forward natural gas prices at December 31, 2011 and 2010. 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 $2.98)	Expected operating revenues (in millions)
2012		
First quarter	30	$ 1
Second quarter	4	—
Third quarter	1	—
Fourth quarter	1	1
2013	1	1
Total at Dec. 31, 2011	37	$ 3
Total at Dec. 31, 2010	28	$16

If Sequent's storage withdrawals associated with existing inventory positions are executed as planned, it expects operating revenues from storage withdrawals of approximately $2 million during the next twelve months and $1 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. For more information on Sequent's energy marketing and risk management activities, see Item 7A, "Quantitative and Qualitative Disclosures About Market Risk - Commodity Price Risk."

Midstream Operations

Our midstream operations segment includes a number of businesses that are related and complementary to our primary business. The most significant of these businesses is our natural gas storage business, which develops, acquires and operates high-deliverability underground natural gas storage assets primarily in the Gulf Coast region of the United States and in northern California. While this business can also generate additional revenue during times of peak market demand for natural gas storage services, the majority of our natural gas storage facilities are covered under a portfolio of short, medium and long-term contracts at a fixed market rate. Golden Triangle Storage began full commercial operations during the first quarter of 2011. Central Valley, located in northern California, is expected to begin commercial operations in the first half of 2012. The following table shows the working gas capacity and subscription amounts by storage facility as of December 31, 2011.

			Working Gas Capacity		Subscribed[3]	
In Bcf	State	Type	Current	Additional Amount Expected in 2012	Amount	%
Jefferson Island	Louisiana	Salt-dome	7.5	—	5.0	67%
Golden Triangle Storage[1]	Texas	Salt-dome	6.0	7.3	4.0	67%
Central Valley[2]	California	Depleted field	—	11.0	3.0	27%
Total			13.5	18.3	12.0	

[1] We expect the second cavern construction to be complete and firm storage services to commence in mid-2012.

[2] We expect construction to be complete and firm storage services to commence in the first half of 2012.

[3] The amount and percentage of capacity under subscription does not include 2 Bcf of capacity under contract at Jefferson Island and 2 Bcf of capacity under contract at Golden Triangle Storage by Sequent at December 31, 2011.

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 interconnections with eight pipelines in the area. The level of firm subscription has remained consistent over the last three years. We will hold an open season for 3 Bcf of subscribed capacity that expires in March 2012 and expect the subscription rate to be significantly 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 caverns would expand the total working gas capacity at Jefferson Island to approximately 19.5 Bcf of working gas capacity.

Golden Triangle Storage This wholly owned subsidiary is designed for an initial 13.3 Bcf of working natural gas capacity. The storage facility 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. We expect Cavern 2 will now consist of 7.3 Bcf of working capacity. Our estimate to complete the second cavern, based on current prices for labor, materials and pad gas, is approximately $28 million. We spent approximately $11 million in capital expenditures for this project in 2011. The total estimated construction cost for Caverns 1 and 2 remains consistent with prior estimates.

At December 31, 2011, of the approximate 6 Bcf of working natural gas capacity available for subscription, Golden Triangle Storage had 4 Bcf of capacity subscribed with a third party and 2 Bcf under contract with Sequent through March 2016. Accordingly, Cavern 1 at Golden Triangle Storage has no remaining capacity available for subscription until March 2013. Cavern 2 is currently unsubscribed, and we will be seeking contracts of varying durations as the in-service date approaches.

Central Valley This wholly owned subsidiary, which joined our business as part of the Nicor merger, is developing an underground natural gas storage facility in the Sacramento River valley of north-central California. We are converting the depleted Princeton Gas Field into a high-deliverability, multi-cycle storage field. This will include the addition of a 14.9 mile 24" diameter gas pipeline connecting the facility to a major pipeline. The storage facility is regulated by the California Commission.

Sawgrass Storage Our 50% owned joint venture (held by Cypress Creek Gas Storage, LLC) with Mill Creek Gas Storage, LLC (an affiliate of Samson Contour Energy E&P, LLC), which joined our business as part of the Nicor merger, is engaged in developing an underground natural gas storage facility northwest of Monroe, Louisiana. In July 2011, Sawgrass Storage applied for a Certificate of Public Convenience and Necessity with the FERC to construct and operate the natural gas storage facility and expects to receive the certificate during 2012.

Horizon Pipeline Our 50% owned joint venture with Natural Gas Pipeline Company of America, Horizon Pipeline, which joined our business as part of the Nicor merger, 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 will primarily consist of storage facilities in northern California and western North America. Storage values have declined over the past two years due to low gas prices and low volatility and we expect this to continue in 2012 and potentially longer.

Cargo Shipping

Our cargo shipping segment, which joined our business as part of the Nicor merger, 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% to 75% of Tropical Shipping's total volumes shipped are in the southbound market, 15% - 20% interisland and 5% – 10% northbound. Tropical Shipping's largest contract consists of a southbound shipment of goods from Canada destined mainly for Puerto Rico. 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" – "Vessels and shipping containers".

Tropical Shipping's operations are structured to allow it 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, such earnings are not expected to be subject to current taxation. In addition, 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 are 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. Approximately 70% of Seven Seas' revenues are generated from Tropical Shipping's customers. The policies' 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. Over the past several years, Tropical Shipping has maintained an average market share of approximately 40% for the ports in which it serves. Tropical Shipping has significantly more market penetration for certain islands versus others. For example, currently it has 45% of the southbound market share for the Virgin Islands versus 20% for the Windward Islands. Tropical Shipping continuously reviews new market opportunities. However, the ability to capture additional market share is difficult due to competition.

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 Bahamas and the Virgin Island economies are highly dependent on tourism from the United States. Whereas, the Caribbean's Windward and Leeward Island economies have more 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.

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 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 nonoperating business units. AGL Services Company is a service company we established to provide certain centralized shared services to our operating segments. We allocate substantially all of AGL Services Company's operating expenses and interest costs to our operating segments in accordance with state regulations. 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. Our other segment also includes intercompany eliminations for transactions between our operating business segments. Our EBIT results include the impact of these allocations to the various operating segments.

Employees

As of February 1, 2012, we had approximately 6,400 employees, 5,850 of whom were in the United States.

The following table provides information about our natural gas utilities' collective bargaining agreements, which represent approximately 26% of our total employees.

	# of Employees	Contract Expiration Date
Nicor Gas		
International Brotherhood of Electrical Workers (Local No. 19)	1,344	Feb. 2014
Virginia Natural Gas		
International Brotherhood of Electrical Workers (Local No. 50)	129	May 2012
Elizabethtown Gas		
Utility Workers Union of America (Local No. 424)	168	Nov. 2012
Total	1,641	

The collective bargaining agreements at Virginia Natural Gas and Elizabethtown Gas expire in 2012. We believe that we have a good working relationship with our unionized employees and there have been no work stoppages at Virginia Natural Gas or Elizabethtown Gas since we acquired those operations in 2000 and 2004, 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 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 2012 annual meeting of shareholders. We expect to file that Proxy Statement with the SEC on or about March 16, 2012, 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, 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.

In 2011, Illinois enacted laws that required Nicor Gas and other large gas utilities in Illinois to elect either to file rate cases with the Illinois Commission in 2012, 2014 and 2016 or sign contracts to purchase SNG to be produced from two coal gasification plants proposed to be constructed in Illinois. On September 30, 2011, Nicor Gas signed an agreement to purchase approximately 25 Bcf of SNG annually from one of the proposed facilities for a 10-year term beginning as early as 2015. For additional information on the substitute natural gas plant legislation. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" – "Contractual Obligations and Commitments."

The Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 introduced a comprehensive new regulatory framework for swaps and security-based swaps. Although the SEC and other regulators are still in the process of adopting rules to implement the new framework, it is possible that Sequent, or other aspects of AGL Resources' operations, could be subject to the new regulations, depending on the ultimate definitions of key terms in the Dodd-Frank Act such as "swap," "swap dealer" and "major swap participant." This may require increased use of working capital for Nicor Gas, SouthStar and Sequent if the regulations increase our collateral requirements related to derivatives utilized to manage risk in these businesses.

We could incur significant compliance costs if we must adjust to new regulations. In addition, as the regulatory environment for our industry increases in complexity, the risk of inadvertent noncompliance could also increase. If we fail to comply with applicable regulations, whether existing or new ones, we could be subject to fines, penalties or other enforcement action by the authorities that regulate our operations, or otherwise be subject to material costs and liabilities.

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 hazardous substances and waste and in connection with spills, releases and emissions of various substances into the environment. Environmental legislation also requires that our facilities, sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Our current costs to comply with these laws and regulations are significant to our results of operations and financial condition. Failure to comply with these laws and regulations and failure to obtain any required permits and licenses may expose us to fines, penalties or interruptions in our operations that could be material to our results of operations.

In addition, claims against us under environmental laws and regulations could result in material costs and liabilities. Existing environmental regulations could also be revised or reinterpreted, new laws and regulations could be adopted or become applicable to us or our facilities, and future changes in environmental laws and regulations could occur. With the trend toward stricter standards, greater regulation, more extensive permit requirements and an increase in the number and types of assets operated by us subject to environmental regulation, our environmental expenditures could increase in the future, particularly if those costs are not fully recoverable from our customers. Additionally, the discovery of presently unknown environmental conditions could give rise to expenditures and liabilities, including fines or penalties, which could have a material adverse effect on our business, results of operations or financial condition.

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

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

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

Presently there are no federally mandated greenhouse gas reduction requirements in the United States. However, there are a number of legislative and regulatory proposals to address greenhouse gas emissions, which are in various phases of discussion or implementation. The outcome of federal and state actions to address global climate change could result in a variety of regulatory programs including potential new regulations, additional charges to fund energy efficiency activities, or other regulatory actions. These actions could:

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

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

Any adoption by federal or state governments mandating a substantial reduction in greenhouse gas emissions could have far-reaching and significant impacts on the energy industry. We cannot predict the potential impact of such laws or regulations on

our future consolidated financial condition, results of operations or cash flows.

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

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

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

The natural gas business is highly competitive, increasingly complex, and we are facing increasing competition from other companies that supply energy, including electric companies, oil and propane providers and, in some cases, energy marketing and trading companies. In particular, the success of our retail businesses is affected by the competition from other energy marketers providing retail natural gas services in our service territories, most notably 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 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.

Retail energy markets fixed-price 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, will primarily consist of storage facilities in northern California and western North America. Storage values have declined over the past two years due to low gas prices and low volatility and we expect this to continue in 2012.

Our cargo shipping segment competes with international maritime companies. The current expansion of the Panama Canal, which is expected to be completed in 2014, 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 to 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. Primarily as a result of the current economic downturn there is increased pricing pressure and decreased shipping volumes for the islands that Tropical Shipping currently serves. Over the past several years Tropical Shipping has maintained an average market share of approximately 40% for the ports it serves. However, 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 slowdown in the United States economy, along with increased mortgage defaults, and significant decreases in new home construction, home values and investment assets, has adversely impacted the financial well-being of many households in the United States. We cannot predict if the administrative and legislative actions to address this situation will be successful in reducing the severity or duration of this 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.

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 and 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.

An adverse decision in the proceeding concerning Nicor Gas' PBR plan could result in an obligation to credit additional amounts to customers which could adversely affect our results of operations, cash flows and financial condition.
On January 1, 2000, Nicor Gas instituted a PBR plan for natural gas costs. 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. There are allegations that Nicor Gas acted improperly in connection with the PBR plan, and the Illinois Commission is reviewing these allegations in a pending proceeding. In October 2011, rebuttal testimony was submitted requesting refunds of $85 million by Staff of the Illinois Commission, $255 million by the Illinois Attorney General's Office and $305 million by the Citizens Utility Board. An adverse decision in this proceeding could result in a credit to ratepayers or other obligations which could adversely affect our business, results of operations, and financial condition.

In February 2012, we committed to a stipulated resolution of certain issues with the staff of the Illinois Commission, which includes crediting Nicor Gas customers $64 million, but does not constitute an admission of fault. The stipulated resolution is subject to review and approval by the Illinois Commission. The Citizens Utility Board and the Illinois Attorney General's Office are not parties to this stipulated resolution and continue to pursue their claims in this proceeding. Evidentiary hearings on this matter are scheduled to begin on February 28, 2012. We do not expect the stipulated resolution to affect our 2011 or 2012 Consolidated Statements of Income, as the $64 million proposed credit is consistent with the estimated liability we recorded for this matter as part of our accounting for the merger with Nicor. See Note 11 to the consolidated financial statements under Item 8 herein, for additional information regarding the PBR plan.

A significant portion of our accounts receivable is subject to collection risks, due in part to a concentration of credit risk at Nicor Gas in Illinois, Atlanta Gas Light and SouthStar in Georgia and at 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 60% 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 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, 2011, Atlanta Gas Light provided services to eleven certificated and active Marketers in Georgia, four of which (based on customer count and including SouthStar) accounted for approximately 30% of our consolidated operating margin for 2011. As a result, Atlanta Gas Light depends on a concentrated number of customers for revenues. The provisions of Atlanta Gas Light's tariff allow it to obtain security support in an amount equal to no less than two times a Marketer's highest month's estimated bill in the form of cash deposits, letters of credit, surety bonds or guaranties. The failure of these Marketers to pay Atlanta Gas Light could adversely affect Atlanta Gas Light's business and results of operations and expose it to difficulties in collecting Atlanta Gas Light's accounts receivable. AGL Resources provides a guarantee to Atlanta Gas Light as security support for SouthStar. Additionally, SouthStar markets directly to end-use customers and has periodically experienced credit losses as a result of severe cold weather or high prices for natural gas that increase customers' bills and, consequently, impair customers' ability to pay.

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

Sequent currently manages the storage and transportation assets of our affiliates Atlanta Gas Light, Virginia Natural Gas, Elizabethtown Gas, Florida City Gas, Chattanooga Gas, and Elkton Gas and shares profits it earns from the management of those assets with those customers and their respective customers, 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 agreement for Atlanta Gas Light is subject to renewal in March 2012. Additionally, the agreement with Florida City Gas expires in March 2013 and the agreements with Chattanooga Gas and Elizabethtown Gas expire in March 2014.

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

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, 2011 had a VaR of $2.2 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 75% of the usage and revenues occur from October through March. Fluctuations in weather 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 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 reduce 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.

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 affect to our results of operations, cash flows and financial condition.

A decrease in the availability of adequate pipeline transportation capacity could reduce our revenues and profits.

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

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

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

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

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

We have confirmed eleven 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, 2011, 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, 2011, projected costs associated with the MGP sites associated with Atlanta Gas Light range from $42 million to $98 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 51.73% of cleanup costs for 23 sites, no portion of the cleanup costs for 14 other sites and 50% of general remediation program costs that do not relate exclusively to particular sites. In addition to the agreement with Commonwealth Edison Company there are 3 sites in which we have sole responsibility. Information regarding preliminary site reviews has been presented to the Illinois Environmental Protection Agency for certain sites. The results of the detailed site-by-site investigations will determine the extent additional remediation is necessary and provide 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. However, we have not performed these probabilistic models for all of our sites. Based on the estimates we have performed the Illinois sites cleanup cost estimates range from $134 to $216 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 sites in New Jersey and North Carolina. Material cleanups of these sites have not been completed nor are precise estimates available for future cleanup costs and therefore considerable variability remains in future cost estimates. For the New Jersey sites, cleanup cost estimates range from $124 million to $174 million. Costs have been estimated for one site in North Carolina and range from $10 million to $16 million.

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 cause us to experience a significant increase in short-term debt because we must pay suppliers for gas when it is purchased, which can be

significantly in advance of when these costs may be recovered through the collection of monthly customer bills for gas delivered. Increases in purchased gas costs also slow our utility collection efforts as customers are more likely to delay the payment of their gas bills, leading to higher-than-normal accounts receivable. This situation results in higher short-term debt levels and increased bad debt expense. Should the price of purchased gas increase significantly during the upcoming Heating Season, we would expect increases in our short-term debt, accounts receivable and bad debt expense during 2012.

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 fired equipment to equipment fueled by other energy sources. However, natural gas prices are expected to remain low and may continue to be lower than they have been historically as a result of a robust natural gas supply, the weak economy and ample storage.

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.
Nicor Gas maintains a noncontributory defined benefit pension plan for 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 note that 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 Retirement 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 plan. 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 or a charge to our other comprehensive income to the extent that the pension fund values are less than the total anticipated liability under the plans. Market declines in the second half of 2008 resulted in significant losses in the value of our pension fund assets. Although the market made a recovery in 2009 and 2010 our pension fund assets are not at the levels they were prior to the market decline in 2008. As a result, based on the current funding status of the AGL plans, we would be required to make a minimum contribution to these plans of approximately $36 million in 2012. We may make additional contributions in 2012 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, 2011 our pension plans assets represented 78% 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 "Retirement Plan Obligations" 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. 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, 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 the 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, 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.

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.

During 2011, our issuances of new debt along with our commercial paper borrowings were primarily used to fund the merger with Nicor, capital expenditures and purchase natural gas inventories for the 2011 / 2012 Heating Season. The amount of our working capital requirements in the near-term will primarily depend on the market price of natural gas and weather. Higher natural gas prices may adversely impact our accounts receivable collections and may require us to increase borrowings under our credit 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 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 2010, after we announced the proposed merger with Nicor, S&P lowered our outlook from stable to negative watch. In December 2011, related to our merger with Nicor, our credit ratings were graded as follows:

- Moody's affirmed the senior unsecured and short-term ratings of the legacy subsidiaries of AGL Resources. Moody's withdrew the short-term rating of Nicor and downgraded the long-term and short-term ratings of Nicor Gas (long-term to A3, from A2, and short-term to P-2 from P-1). Moody's affirmed the Stable outlook for all of our entities.
- S&P affirmed its rating of AGL Capital (BBB+), while lowering the corporate credit ratings on AGL Resources and its subsidiaries (Atlanta Gas Light and Nicor Gas). The corporate credit rating of AGL Resources and Atlanta Gas Light was downgraded from A- to BBB+ while the corporate credit rating of Nicor Gas was downgraded from AA to BBB+. S&P indicated the downgrade primarily stems from our increased financial leverage resulting from the Nicor merger. S&P rated both the AGL Capital and Nicor Gas commercial paper programs at A-2. As a result of these actions, S&P removed the Negative Watch and noted the outlook is now Stable.
- Fitch affirmed its ratings on AGL Resources and its subsidiaries (A-) and Nicor Gas (A), with a Stable outlook. Fitch noted that our consolidated financial profile is pressured, and that with the addition of acquisition-related debt, our consolidated credit metrics are weak for the ratings category. Fitch indicated that long-term ratings stability will depend on reduction in leverage through successful integration and the realization of operating synergies.

As of December 31, 2011, if our credit rating had fallen below investment grade, we would have been required to provide collateral of approximately $48 million to continue conducting business with certain counterparties.

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

We are subject to interest rate risk in connection with the issuance of fixed-rate and variable-rate debt. In order to maintain our desired mix of fixed-rate and variable-rate debt, we may use interest rate swap agreements and exchange fixed-rate and variable-rate interest payment obligations over the life of the arrangements, without exchange of the underlying principal amounts. For additional information, see Item 7A, "Quantitative and Qualitative Disclosures About Market Risk." We cannot ensure that we will be successful in structuring such swap agreements to manage our risks effectively. If we are unable to do so, our earnings may be reduced. In addition, higher interest rates, all other things equal, reduce the earnings that we derive from transactions where we capture the difference between authorized returns and short-term borrowings.

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

A 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 cash in the form of dividends or other distributions from our subsidiaries to meet our cash requirements. The ability of our subsidiaries to pay dividends and make other distributions is subject to applicable state law. 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 dividend restriction information.

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

As a result of cross-default provisions in our borrowing arrangements, we may be unable to satisfy all our outstanding obligations in the event of a default on our part.
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 other of our debt agreements, obligated in such instance to satisfy a large portion of our outstanding indebtedness and unable to satisfy all our outstanding obligations simultaneously.

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. For example, the Illinois corporate income tax rate was increased effective January 1, 2011. 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.

We are involved in legal or administrative proceedings before various courts and governmental bodies that could adversely affect our results of operations, cash flows and financial condition.
We are involved in legal or administrative proceedings before various courts and governmental bodies with respect to general claims, rates, taxes, environmental issues, billing, credit and collection matters, intersegment services, gas cost prudence reviews and other matters. Adverse decisions regarding these matters, to the extent they require us to make payments in excess of amounts provided for in our financial statements, could adversely affect our results of operations, cash flows and financial condition.

Risks Related to Our Merger with Nicor

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

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.

The anticipated benefits of combining Nicor with us may not be realized.
We entered into the Merger Agreement with the expectation that the merger would result in various benefits, including, among other things, increased operating efficiencies and reduced costs. Although we expect to achieve the anticipated benefits of the merger, achieving them is subject to a number of uncertainties, including:

- the ability to combine certain of our operations or take advantage of expected growth opportunities
- general market and economic conditions
- general competitive factors in the marketplace
- higher than expected costs required to achieve the anticipated benefits of the merger.

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

The integration of AGL Resources and Nicor will present significant challenges that may result in a decline in the anticipated potential benefits of the merger.
The difficulties of combining operations include:

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

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

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

The combined company recorded goodwill and intangible assets that could become impaired and adversely affect the combined company's operating results.
We accounted for the merger as a purchase in accordance with GAAP. Under the purchase method of accounting, the assets and liabilities of Nicor were recorded, as of the date of the merger, at their respective fair values and added to our assets and liabilities. Our reported financial condition and results of operations issued after completion of the merger reflect Nicor balances and results after completion of the merger, but do not restate retroactively to reflect the historical financial position or results of operations of Nicor for periods prior to the merger. The earnings of the combined company reflect purchase accounting adjustments.

Under the purchase method of accounting, the total purchase price was allocated to Nicor's tangible assets and liabilities and identifiable intangible assets based on their fair values as of the date of the merger. Identifiable intangible assets of $103 million were recorded. The fair value of Nicor's assets and liabilities subject to the rate setting practices of their regulators approximate their carrying value. The excess of the purchase price over identifiable fair values was recorded as goodwill in the amount of approximately $1.4 billion. To the extent the value of goodwill or intangibles becomes impaired, the combined company may be required to incur impairment charges that could have a material impact on the combined company's operating results.

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, 2011 was approximately $4.9 billion (including approximately $1.3 billion of short-term borrowings and approximately $3.6 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.

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, 2011, our distribution operations segment owned approximately 80,000 miles of underground distribution and transmission mains. The 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 7.5 Bcf of LNG storage capacity in five LNG plants located in Georgia, New Jersey and Tennessee. In addition, we own two propane storage facilities in Virginia that have a combined storage capacity of approximately 0.5 Bcf. The LNG plants and propane storage facilities are used by our distribution operations segment to supplement natural gas supply during peak usage periods.

Midstream Operations We currently 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 7.2 Bcf of working gas capacity. Golden Triangle Storage operates a salt-dome storage facility in Texas designed for approximately 13.3 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 an expected 7.3 Bcf of working capacity, is expected to be placed into commercial service in mid-2012. Central Valley is developing an underground natural gas storage facility in California with an expected 11 Bcf of working natural gas capacity and is expected to be placed into commercial service in mid-2012.

Vessels and shipping containers

Our cargo shipping segment operates 12 owned vessels and 2 chartered vessels with a container capacity totaling approximately 5,500 TEUs. The owned vessels range in age from 1 – 35 years, and vary in length from 249 – 491 feet. In addition to the vessels, the company owns and/or leases 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 the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Holders of Common Stock, Stock Price and Dividend Information

Our common stock is listed on the New York Stock Exchange. On December 16, 2011, our ticker symbol changed from AGL to GAS. At January 31, 2012, there were 17,770 record holders of our common stock, which represents an increase of approximately 8,500 from the same period in 2011. The increase in the number of record holders and the change in our ticker symbol were primarily the result of the completion of our merger with Nicor on December 9, 2011. Quarterly information concerning our high and low stock prices and cash dividends paid in 2011 and 2010 is as follows:

	Sales price of common stock		Cash dividend per common share
Quarter ended:	High	Low	
2011			
March 31, 2011	**$39.91**	**$35.65**	**$0.45**
June 30, 2011	**42.34**	**38.58**	**0.45**
September 30, 2011	**42.40**	**34.08**	**0.45**
December 31, 2011[1]	**43.69**	**37.95**	**0.55**
			$1.90
2010			
March 31, 2010	$38.83	$34.26	$0.44
June 30, 2010	40.08	34.72	0.44
September 30, 2010	40.00	35.29	0.44
December 31, 2010	39.66	34.21	0.44
			$1.76

[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 256 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 our ability to satisfy our obligations under certain financing agreements, including debt-to-capitalization covenants.

Under Georgia law, the payment of cash dividends to the holders of our common stock is limited to our legally available assets and subject to the prior payment of dividends on any outstanding shares of preferred stock. Our assets are not legally available for paying cash dividends if, after payment of the dividend:

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

Issuer Purchases of Equity Securities

There were no purchases of our common stock by us and any affiliated purchasers during the three months ended December 31, 2011, as set forth in the following table. Stock repurchases may be made in the open market or in private transactions at times and in amounts that we deem appropriate. However, there is no guarantee as to the exact number of additional shares that may be repurchased, and we may terminate or limit the stock repurchase program at any time. We currently anticipate holding the repurchased shares as treasury shares.

Period	Total number of shares purchased[1]	Average price paid per common share	Total number of shares purchased as part of publicly announced plans or programs	Maximum number of shares that may yet be purchased under the publicly announced plans or programs
October 2011	—	$—	—	—
November 2011	—	—	—	—
December 2011	—	—	—	—
Total fourth quarter	—	$—	—	—

[1] On March 20, 2001, our Board of Directors approved the purchase of up to 600,000 shares of our common stock in the open market to be used for issuances under the Officer Incentive Plan (Officer Plan). We did not purchase any shares for such purposes in the fourth quarter of 2011. As of December 31, 2011, we had purchased a total 383,591 of the 600,000 shares authorized for purchase, leaving 216,409 shares available for purchase under this program.

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 2010 to 2011 are primarily due to the Nicor merger 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	2011[1]	2010	2009	2008	2007
Income statement data					
Operating revenues	**$ 2,338**	$2,373	$2,317	$2,800	$2,494
Operating expenses					
Cost of goods sold	**1,097**	1,164	1,142	1,654	1,369
Operation and maintenance[2]	**490**	497	497	472	451
Depreciation and amortization	**186**	160	158	152	144
Nicor merger expenses[2]	**68**	6	—	—	—
Taxes other than income taxes	**57**	46	44	44	41
Total operating expenses	**1,898**	1,873	1,841	2,322	2,005
Operating income	**440**	500	476	478	489
Other income (expense)	**7**	(1)	9	6	4
Earnings before interest and taxes (EBIT)[3]	**447**	499	485	484	493
Interest expenses	**136**	109	101	115	125
Earnings before income taxes	**311**	390	384	369	368
Income taxes	**125**	140	135	132	127
Net income	**186**	250	249	237	241
Less net income attributable to the noncontrolling interest	**14**	16	27	20	30
Net income attributable to AGL Resources Inc.	**$ 172**	$ 234	$ 222	$ 217	$ 211
Common stock data					
Weighted average common shares outstanding basic	**80.4**	77.4	76.8	76.3	77.1
Weighted average common shares outstanding diluted	**80.9**	77.8	77.1	76.6	77.4
Total shares outstanding[4]	**117.0**	78.0	77.5	76.9	76.4
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	**$ 2.14**	$ 3.02	$ 2.89	$ 2.85	$ 2.74
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	**$ 2.12**	$ 3.00	$ 2.88	$ 2.84	$ 2.72
Dividends declared per common share[5]	**$ 1.90**	$ 1.76	$ 1.72	$ 1.68	$ 1.64
Dividend payout ratio	**89%**	58%	60%	59%	60%
Dividend yield[6]	**4.5%**	4.9%	4.7%	5.4%	4.4%
Price range:					
High	**$ 43.69**	$40.08	$37.52	$39.13	$44.67
Low	**$ 34.08**	$34.21	$24.02	$24.02	$35.24
Close[4]	**$ 42.26**	$35.85	$36.47	$31.35	$37.64
Market value[4]	**$ 4,946**	$2,800	$2,826	$2,411	$2,876
Statements of Financial Position data[4]					
Total assets	**$13,913**	$7,520	$7,079	$6,710	$6,258
Property, plant and equipment – net	**7,900**	4,405	4,146	3,816	3,566
Short-term debt	**1,338**	1,033	602	866	580
Long-term debt	**3,561**	1,671	1,974	1,675	1,675
Total debt	**4,899**	2,704	2,576	2,541	2,255
Total equity	**3,339**	1,836	1,819	1,684	1,708
Cash flow data					
Net cash flow provided by operating activities	**$ 451**	$ 526	$ 592	$ 227	$ 377
Net cash flow used in investing activities	**(1,339)**	(442)	(476)	(372)	(253)
Net cash flow (used in) provided by financing activities	**933**	(86)	(106)	142	(122)
Net borrowings and (payments) of short-term debt	**91**	131	(264)	286	52
Financial ratios[4]					
Debt	**59%**	60%	59%	60%	57%
Equity	**41%**	40%	41%	40%	43%
Total	**100%**	100%	100%	100%	100%
Return on average equity	**6.6%**	12.8%	12.7%	12.8%	12.6%

[1] Material changes from 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. [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

Merger with Nicor On December 9, 2011, we closed the merger with Nicor. We are now the nation's largest natural gas-only distribution company based on customer count. The merger created a combined company with increased scale and scope in both regulated utility and non-regulated businesses as indicated below:

- Seven regulated natural gas distribution companies providing natural gas services to approximately 4.5 million customers in Illinois, Georgia, Virginia, New Jersey, Florida, Tennessee and Maryland
- Over 1 million retail customers in the unregulated businesses
- Physical wholesale gas business delivering approximately 5.2 Bcf of natural gas per day
- Natural gas storage facilities that are expected to provide approximately 31.8 Bcf of working gas storage capacity in 2012

As a result of our merger with Nicor some of our businesses have been reclassified to different segments. See Note 13 to our consolidated financial statements under Item 8 herein for additional segment information including recasted prior period information. The following table provides more information on our segments.

	EBIT[2]			Assets[3]			Capital Expenditures[3]		
	2011	2010	2009	**2011**	2010	2009	**2011**	2010	2009
Distribution operations	**80%**	70%	67%	**79%**	73%	74%	**85%**	70%	74%
Retail operations	**18**	21	22	**4**	3	4	**1**	1	1
Wholesale services	**1**	10	10	**9**	18	16	**—**	—	—
Midstream operations	**2**	1	1	**4**	6	5	**8**	25	23
Cargo shipping	**—**	n/a	n/a	**5**	n/a	n/a	**—**	n/a	n/a
Other[1]	**(1)**	(2)	—	**(1)**	—	1	**6**	4	2
Total	**100%**	100%	100%	**100%**	100%	100%	**100%**	100%	100%

[1] The 2011 results exclude the effects of the $68 million of merger expenses which were reported within our other segment.

[2] The year ending December 31, 2011 only includes 22 days of Nicor activity from December 10, 2011 through December 31, 2011.

[3] The 2011 amounts include Nicor assets as of December 31, 2011.

Over the last three years, on average, we have derived 72% of our operating segments' EBIT from our regulated natural gas distribution business whose rates are approved by state regulatory commissions. We derived our remaining operating segment's EBIT for the last three years principally from businesses that are complementary to our natural gas distribution business. These businesses include the sale of natural gas to retail customers, natural gas asset management and the operation of high-deliverability natural gas underground storage as ancillary activities to our regulated utility franchises. The increased impact of the rate-regulated distribution operations segment on our overall business is expected to reduce our exposure to market fluctuations.

For additional information on the Nicor merger see Item 1-Business as well as Note 3 to our consolidated financial statements under Item 8 herein.

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.

On December 20, 2011, the Virginia Commission approved an annual increase of $11 million in base rate revenues and established an authorized return on equity of 10% for Virginia Natural Gas with an overall return on rate base set at 7.38%. Additionally, $3.1 million of costs previously recovered through base rates will now be recovered through the company's gas cost recovery rate. Customer's bills will be credited to refund the difference between the final approved rates and interim rate increase, which began with usage on and after October 1, 2011. The new rate is expected to increase the average residential customer's monthly bill by less than $3.50 per month depending on usage.

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

operations segments throughout 2011. Our year-over-year consolidated utility customer gain rate was 0.1% in 2011, compared to a loss rate of (0.1)% for 2010. We anticipate overall competition and customer trends in 2012 to be similar to our 2011 results. In addition, for the full year 2011 Nicor Gas increased their customer count by 0.4% compared to 0.2% for 2010.

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. On October 10, 2011, Georgia Natural Gas was named the exclusive natural gas partner for the Delta Air Lines Inc. Delta SkyMiles Program in Georgia. This is a long-term partnership and we expect it will help retain current customers as well as attract new customers from other Marketers in Georgia.

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 2008 and 2009, daily Henry Hub spot market prices for natural gas in the United States were extremely volatile. However, during 2010 and 2011, the volatility of natural gas prices has been 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 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 wholesales 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 Statements of Financial Position items such as receivables, unbilled revenue, inventories and short-term debt across quarters. However, these items are comparable when reviewing our annual results.

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.

Approximately 71% of these segments' operating revenues and 92% of these segments' EBIT for the year ended December 31, 2011 were generated during the first and fourth quarters of 2011, and are reflected in our Consolidated Statements of Income for the quarters ended March 31, 2011 and December 31, 2011. 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. As a result of our merger with Nicor, our results of operations for the year ending December 31, 2011 includes 22 days of Nicor activity from December 10, 2011 through December 31, 2011. See Note 3 for additional merger related information and Note 13 to our consolidated financial statements under Item 8 herein for additional information regarding reclassification of our business segments. The following table provides more information regarding the components of our operating revenues.

In millions	2011	2010	2009
Residential	**$1,065**	$1,083	$1,091
Commercial	**467**	521	467
Transportation	**403**	404	378
Industrial	**289**	205	185
Other	**114**	160	196
Total operating revenues	**$2,338**	$2,373	$2,317

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

In millions	2011	2010	2009
Operating revenues	**$ 2,338**	$ 2,373	$ 2,317
Cost of goods sold	**(1,097)**	(1,164)	(1,142)
Revenue tax expense[1]	**(9)**	—	—
Operating margin	**1,232**	1,209	1,175
Operating expenses[2]	**(733)**	(703)	(699)
Revenue tax expense[1]	**9**	—	—
Nicor merger expenses[3]	**(68)**	(6)	—
Operating income	**440**	500	476
Other income (expense)	**7**	(1)	9
EBIT	**447**	499	485
Interest expenses	**136**	109	101
Earnings before income taxes	**311**	390	384
Income tax expenses	**125**	140	135
Net income	**186**	250	249
Less net income attributable to the noncontrolling interest	**14**	16	27
Net income attributable to AGL Resources Inc.	**$ 172**	$ 234	$ 222

[1] Adjusted for revenue tax expenses for Nicor Gas which are passed directly through to customers.

[2] Excludes transaction expenses associated with the merger with Nicor of approximately $68 million ($55 million net of tax) in 2011 and $6 million ($4 million net of tax) in 2010.

[3] Transaction expenses associated with the Nicor merger are part of operating expenses, but are shown separately to better compare year-over-year results.

In 2011, our net income attributable to AGL Resources Inc. decreased by $62 million or 26% compared to last year. The decrease was primarily the result of approximately $68 million ($55 million net of tax) of transaction expenses associated with the merger with Nicor in 2011, which were expensed as incurred. We incurred approximately $6 million ($4 million net of tax) of Nicor transaction costs in 2010. Additionally, we experienced reduced EBIT at wholesale services and retail 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.

In 2010, our net income attributable to AGL Resources Inc. increased by $12 million from the prior year primarily due to increased EBIT at distribution operations largely due to new rates at Atlanta Gas Light and Elizabethtown Gas as well as the completion of the Hampton Roads project by Virginia Natural Gas. The increase in our net income attributable to AGL Resources Inc. was also favorably impacted by increased EBIT at wholesale services and our additional 15% ownership interest in SouthStar, which was effective January 1, 2010. This was partly offset by increased interest expense and decreased EBIT at retail operations, midstream operations and other. The decrease in EBIT at retail operations was mainly attributable to increased operating expenses. The variances for each operating segment are contained within the year-over-year 2011 compared to year-over-year discussion on the following pages.

Interest expense In 2011, our interest expense increased by approximately $27 million. This increase was primarily the result of our prefunding the cash portion of the merger consideration through the issuance of approximately $975 million of long-term debt during the year. This increased our annual interest expense by approximately $17 million. The remaining increase during 2011 related primarily to fees paid on our Term Loan Facility and our Bridge Facility.

The increase in our interest expenses of $8 million in 2010 compared to 2009 was primarily the result of fluctuations in short-term interest rates and higher average debt levels. The following table provides additional detail on interest expense for the last three years and the primary items that affect year-over-year change.

In millions	2011	2010	2009
Interest expense	**$ 136**	$ 109	$ 101
Average debt outstanding[1]	**$2,652**	$2,393	$2,239
Average rate[2]	**5.1%**	4.6%	4.5%

[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 Our income tax expense in 2011 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, 37.5% in 2010 and 37.8% in 2009. The increased effective tax rate in 2011 was primarily due to non-deductible merger transaction expenses. Our income tax expense in 2010 increased by $5 million or 4% compared to 2009 primarily due to higher consolidated earnings.

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 2011, 2010 and 2009, 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. Our customer metrics highlight the average number of customers to which we provide services. This number of customers can be impacted by natural gas prices, economic conditions and competition from alternative fuels.

Volume metrics for distribution operations and retail operations present the effects of weather and our customers' demand for natural gas. Wholesale services' daily physical sales represent the daily average natural gas volumes sold to its customers. Within our 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.

Weather

Heating degree days[1]	Normal	Year ended December 31, 2011	2010	2009	2011 vs. 2010 colder (warmer)	2010 vs. 2009 colder (warmer)	2011 vs. normal colder (warmer)	2010 vs. normal colder (warmer)	2009 vs. normal colder (warmer)
Georgia	2,679	2,454	3,209	2,803	(24)%	14%	(8)%	20%	5%
Virginia	3,182	2,945	3,601	3,312	(18)%	9%	(7)%	13%	4%
New Jersey	4,639	4,275	4,445	4,755	(4)%	(7)%	(8)%	(4)%	3%
Florida	551	310	1,108	548	(72)%	102%	(44)%	101%	(1)%
Tennessee	3,085	2,953	3,594	3,154	(18)%	14%	(4)%	16%	2%
Maryland	4,696	4,489	4,679	4,783	(4)%	(2)%	(4)%	—	2%
Ohio	4,898	4,656	5,181	4,919	(10)%	5%	(5)%	6%	—

Heating degree days[1]	Normal	Quarter ended December 31, 2011	2010	2009	2011 vs. 2010 colder (warmer)	2010 vs. 2009 colder (warmer)	2011 vs. normal colder (warmer)	2010 vs. normal colder (warmer)	2009 vs. normal colder (warmer)
Georgia	1,036	852	1,187	1,182	(28)%	—	(18)%	15%	14%
Virginia	1,091	853	1,380	1,065	(38)%	30%	(22)%	26%	(2)%
New Jersey	1,620	1,328	1,720	1,618	(23)%	6%	(18)%	6%	—
Florida	174	66	365	158	(82)%	131%	(62)%	110%	(9)%
Tennessee	1,216	1,104	1,382	1,283	(20)%	8%	(9)%	14%	6%
Maryland	1,673	1,463	1,822	1,665	(20)%	9%	(13)%	9%	—
Ohio	1,828	1,563	2,028	1,893	(23)%	7%	(14)%	11%	1%

Customers

(average end-use - in thousands)	Year ended December 31, 2011	2010	2009	2011 vs. 2010 % change	2010 vs. 2009 % change
Distribution Operations					
Nicor Gas[2]	2,188	n/a	n/a	n/a%	n/a%
Atlanta Gas Light	1,541	1,544	1,549	(0.2)	(0.3)
Virginia Natural Gas	278	275	273	1.1	0.7
Elizabethtown Gas	276	274	273	0.7	0.4
Florida City Gas	103	103	103	—	—
Chattanooga Gas	62	62	62	—	—
Elkton Gas	6	6	6	—	—
Total	4,454	2,264	2,266	n/a%	(0.1)%
Retail Operations					
Georgia	485	496	504	(2)%	(2)%
Ohio and Florida[3]	96	77	103	25%	(25)%
Total	581	573	607	1%	(6)%
Market share in Georgia	33%	33%	33%	—	—

Volumes

In billion cubic feet (Bcf)	Year ended December 31, 2011	2010	2009	2011 vs. 2010 % change	2010 vs. 2009 % change
Distribution Operations					
Firm	247	243	218	2%	11%
Interruptible	105	99	98	6%	1%
Total	352	342	316	3%	8%
Retail Operations					
Georgia firm	35	46	40	(24)%	15%
Ohio and Florida	9	10	11	(10)%	(9)%
Wholesale Services					
Daily physical sales (Bcf / day)[4]	5.21	4.57	2.96	14%	54%

	As of December 31, 2011	2010	2009
Midstream Operations			
Working natural gas capacity	13.5	13.5	7.5
% of capacity under subscription[5]	68%	51%	67%

[1] Obtained from weather stations relevant to our service areas at the National Oceanic and Atmospheric Administration, National Climatic Data Center. Normal represents ten-year averages from January 1, 2002 through December 31, 2011. Does not include any heating degree data for Illinois. [2] Nicor Gas customer data is as of December 31, 2011. [3] A portion of the Ohio customers represents customer equivalents, which are computed by the actual delivered volumes divided by the expected average customer usage. [4] As of December 31, for each respective year, and represents volume information only from December 10, 2011 through December 31, 2011 for the entities acquired from Nicor. [5] The percentage of capacity under subscription does not include 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 and at December 31, 2009.

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

In millions	Operating margin[1]	Operating expenses	EBIT[1]
2011[3]			
Distribution operations	**$ 963**	**$557**	**$412**
Retail operations	**168**	**75**	**93**
Wholesale services	**57**	**52**	**5**
Midstream operations	**37**	**28**	**9**
Cargo shipping	**7**	**8**	**–**
Other[2]	**–**	**72**	**(72)**
Consolidated	**$1,232**	**$792**	**$447**
2010			
Distribution operations	$ 879	$531	$352
Retail operations	183	80	103
Wholesale services	105	57	49
Midstream operations	30	24	6
Cargo shipping	n/a	n/a	n/a
Other[2]	12	17	(11)
Consolidated	$1,209	$709	$499
2009			
Distribution operations	$ 840	$522	$327
Retail operations	181	76	105
Wholesale services	111	64	47
Midstream operations	22	19	3
Cargo shipping	n/a	n/a	n/a
Other[2]	21	18	3
Consolidated	$1,175	$699	$485

[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" herein. 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. See Note 13 to our consolidated financial statements under Item 8 herein for additional segment information.

[2] The increase in operating expenses for 2011 is primarily due to $68 million in transaction expenses associated with the merger with Nicor. For more information see Note 3 to our consolidated financial statements under Item 8 herein. Additionally, includes intercompany eliminations.

[3] Operating margin and expense for 2011 are adjusted for revenue tax expense for Nicor Gas which is passed directly through to customers.

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 all of our utilities' respective service areas.

In millions	2011	2010
EBIT – prior year	**$352**	$327
Operating margin		
Increased margin from Nicor Gas as a result of the Nicor merger in December 2011	**47**	–
Increased revenues from new rates and regulatory infrastructure program revenues at Atlanta Gas Light	**33**	9
Increased revenues from customer growth, higher usage and enhanced infrastructure program revenues at Elizabethtown Gas	**6**	6
Increased revenues from the Hampton Roads project at Virginia Natural Gas	**–**	21
(Decreased) increased revenues from usage at Florida City Gas due to weather	**(2)**	3
Decreased margins from gas storage carrying amounts at Atlanta Gas Light	**(2)**	(1)
Other	**2**	1
Increase in operating margin	**84**	39
Operating expenses		
Increased expenses for Nicor Gas as a result of the Nicor merger in December 2011	**31**	–
Increased depreciation expense	**10**	4
Increased pension expense	**2**	4
(Decreased) increased payroll and incentive compensation expense	**(14)**	9
(Decreased) increased marketing costs	**(1)**	1
Decreased bad debt expenses	**(4)**	(3)
Increased (decreased) outside services and other expenses	**2**	(6)
Increase in operating expenses	**26**	9
Increase (decrease) in other income	**2**	(5)
EBIT – current year	**$412**	$352

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 mitigate potential weather impacts.

In millions	2011	2010
EBIT – prior year	**$103**	$105
Operating margin		
(Decreased) increased average customer usage and warmer than prior year weather, net of weather derivatives	**(15)**	9
Change in LOCOM adjustment	**(5)**	6
(Decreased) increased operating margins for Florida, Ohio and interruptible customers	**(2)**	1
Change in retail pricing plan mix and decrease in average number of customers	**(4)**	(12)
Increased (decreased) contributions from the management and optimization of storage and transportation assets, and from retail price spreads	**7**	(1)
Increased margin as a result of the Nicor merger in December 2011	**5**	—
Other	**(1)**	(1)
(Decrease) increase in operating margin	**(15)**	2
Operating expenses		
(Decreased) bad debt expense	**(3)**	—
(Decreased) increased legal expense	**(4)**	3
Increased expenses as a result of the Nicor merger in December 2011	**3**	—
Other	**(1)**	1
(Decrease) increase in operating expenses	**(5)**	4
EBIT – current year	**$ 93**	$103

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	2011	2010
EBIT – prior year	**$ 49**	$ 47
Operating margin		
Change in storage hedge gains as a result of declining NYMEX natural gas prices	**8**	28
Increased (decreased) gains on transportation hedges from the narrowing of transportation basis spreads	**13**	(42)
Change in commercial activity	**(45)**	10
Change in LOCOM adjustment, net of hedging recoveries	**(24)**	(2)
Decrease in operating margin	**(48)**	(6)
Operating expenses		
Decreased incentive compensation costs	**(5)**	(8)
Other	**—**	1
Decrease in operating expenses	**(5)**	(7)
(Decreased) increased other income	**(1)**	1
EBIT – current year	**$ 5**	$ 49

Change in Commercial activity The reduction in commercial activity in 2011 reflects significantly lower natural gas price volatility impacting daily and intra-day storage and transportation spreads, as well as losses associated with the forward purchase and sale of natural gas generally held for use under forward transportation contracts. Our wholesale services segment also incurred credit losses of $4 million during 2011 associated with a counterparty that filed for bankruptcy during the early part of the third quarter.

Natural gas shale production in the Northeast, specifically from the Marcellus region, resulted in pipeline capacity constraints. During the second half of 2011, our wholesale services segment experienced constraints for natural gas purchased from producers in the Marcellus shale gas producing region, resulting in the sale of natural gas at a loss, higher transportation costs and the costs to renegotiate certain of Sequent's producer contracts. Total losses related to these constraints during 2011 were approximately $18 million.

Change in storage and transportation hedges Seasonal (storage) and geographical location (transportation) spreads continue to be significantly lower than in 2010 and overall natural gas price volatility remained low during the second half of 2011. Gains in 2011 and 2010 were primarily due to significantly larger seasonal and geographical location spreads at the time the hedges of our storage and transportation positions were executed and the subsequent downward movement of natural gas prices and collapse of regional transportation spreads during 2011 and 2010.

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

In millions	2011	2010	2009
Commercial activity recognized	**$ 32**	$ 77	$ 67
Gain on transportation hedges	**14**	1	43
Gain on storage hedges	**37**	29	1
Inventory LOCOM adjustment, net of estimated current period recoveries	**(26)**	(2)	—
Operating margin	**$ 57**	$105	$111

For more information on Sequent's expected operating revenues from its storage inventory in 2012 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 our natural gas storage business, which develops, acquires and operates high-deliverability underground natural gas storage assets. While this business can also generate additional revenue during times of peak market demand for natural gas storage services, the majority of our storage services are covered under medium to long-term contracts at a fixed market rate. For more information on our operating segments, see Item 1, "Business."

In millions	2011	2010
EBIT – prior year	**$ 6**	$ 3
Operating margin		
Increased revenues at Golden Triangle Storage as a result of the start of commercial service in September 2010	**7**	4
Decreased revenues at Jefferson Island as a result of lower subscription rates	**(2)**	—
Other – primarily increased revenues in 2010 for Magnolia pipeline project	**2**	4
Increase in operating margin	**7**	8
Operating expenses and other loss		
Increased operating and depreciation expenses at Golden Triangle Storage as a result of the start of commercial service in September 2010	**7**	4
Decreased outside services and other expenses at Jefferson Island	**—**	(2)
Other – primarily lower project development costs in 2011	**(3)**	3
Increase in operating expenses	**4**	5
EBIT – current year	**$ 9**	$ 6

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 an immaterial EBIT for the 22 days following the close of our merger with Nicor for the period ending December 31, 2011.

Liquidity and Capital Resources

Overview The acquisition of natural gas and pipeline capacity, payment of dividends, and working capital requirements are our most significant short-term financing requirements. The need for long-term capital is driven primarily by capital expenditures and maturities of long-term debt. The liquidity required to fund our working capital, capital expenditures and other cash needs is primarily provided by our operating activities. Our short-term cash requirements not met by cash from operations are primarily satisfied with short-term borrowings under our commercial paper 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 has continued to focus 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 issuance of various securities, including long-term and short-term debt and equity, is subject to customary approval or review by state and federal regulatory bodies including the various commissions of the states in which we conduct business, the SEC and the FERC. Furthermore, a substantial portion of our consolidated assets, earnings and cash flow 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 $465 million at December 31, 2011.

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, construction 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, 2011, we had approximately $71 million 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, and if we repatriate all or a portion of Tropical Shipping's earnings in the form of a dividend we 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.

Merger Financing On December 9, 2011, we closed our merger with Nicor at which time each outstanding share of Nicor common stock, other than shares to be cancelled and Dissenting Shares, as defined in the Merger Agreement, was converted into the right to receive consideration of (i) 0.8382 of a share of AGL Resources common stock and (ii) $21.20 in cash. Fractional shares were paid in cash as were stock options and restricted stock units that were awarded to Nicor employees for pre-merger services. The total value of the consideration paid to Nicor common shareholders was approximately $2.5 billion based primarily upon the volume-weighted average price of AGL Resources common stock on the New York Stock Exchange on December 8, 2011, and the number of Nicor common shares outstanding as of the Effective Date, as defined in the Merger Agreement. Upon closing the merger, we assumed all of Nicor's outstanding debt, the fair value of which was approximately $1.0 billion.

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.

As a result of the merger with Nicor, we assumed the first mortgage bonds of Nicor Gas, which at December 31, 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.

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. In addition, credit ratings are important to our counterparties when we engage in certain transactions including over-the-counter 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. Each rating should be evaluated independently of other ratings. 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, including 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.

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. The following table summarizes our credit ratings as of December 31, 2011.

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

Nicor Gas	S&P	Moody's	Fitch
Corporate rating	BBB+	n/a	A
Commercial paper	A-2	P-2	F-1
Senior unsecured	BBB+	A3	A+
Senior secured	A	A1	AA-
Ratings outlook	Stable	Stable	Stable

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 and noted the outlook is now stable. Fitch affirmed its ratings for both AGL Resources and Nicor Gas. 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.

The primary reason for the 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. These credit rating changes are not expected to materially impact our borrowing costs. It is expected that long-term rating stability will depend on a reduction in leverage through successful merger integration and the realization of operating synergies.

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 any interest or principal when due, the failure to furnish financial statements within the timeframe established by each debt facility, the failure to comply with certain affirmative and negative covenants, cross-defaults to certain other material indebtedness in excess of specified amounts, incorrect or misleading representations or warranties, insolvency or bankruptcy, fundamental change of control, the occurrence of certain Employee Retirement Income Security Act events, judgments in excess of specified amounts and certain impairments to the guarantee.

Our credit 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 also 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 the exclusion of other comprehensive income pension adjustments. 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,
	2011	2010	**2011**
Debt-to-capitalization ratio	**58%**	58%	**60%**

We were in compliance with all of our debt provisions and covenants, both financial and non-financial, as of December 31, 2011 and 2010.

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,	
	2011	2010
Short-term debt	**16%**	23%
Long-term debt	**43**	37
Total debt	**59**	60
Equity	**41**	40
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	2011	2010	2009
Net cash provided by (used in):			
Operating activities	**$ 451**	$ 526	$ 592
Investing activities	**(1,339)**	(442)	(476)
Financing activities	**933**	(86)	(106)
Net increase (decrease) in cash and cash equivalents	**45**	(2)	10
Cash and cash equivalents at beginning of period	**24**	26	16
Cash and cash equivalents at end of period	**$ 69**	$ 24	$ 26

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.

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 of $68 million 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.

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

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

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

Cash Flow from Investing Activities Our net cash used in investing activities consisted primarily of our $912 million payment for the cash portion of the purchase consideration, net of cash that was acquired in the Nicor merger. Additionally, we incurred PP&E expenditures, the majority of which were within our distribution operations and midstream operations segments. Our estimated PP&E expenditures for 2012 and our actual PP&E expenditures incurred in 2011, 2010 and 2009 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 and Elizabethtown Gas' utility infrastructure enhancements program
- **Pipeline projects** – projects include (i) Hampton Roads, a Virginia Natural Gas pipeline project, which connects its northern and southern systems and (ii) Magnolia Pipeline, which diversifies our sources of natural gas by connecting our Georgia service territory to the Elba Island LNG terminal
- **Natural gas storage** – additional 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	2012[1]	2011[2]	2010	2009
Distribution business	$376	**$159**	$159	$132
Regulatory infrastructure programs	286	**192**	186	76
Pipeline projects	—	**—**	3	136
Natural gas storage	66	**22**	114	95
Other	81	**54**	48	37
Total	$809	**$427**	$510	$476

[1] Estimated PP&E expenditures.

[2] Only includes Nicor expenditures subsequent to the merger date of December 9, 2011.

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

Our estimated expenditures for 2012 include discretionary spending for capital projects principally within the distribution business, regulatory infrastructure programs and other categories. We continually evaluate whether to proceed with these projects, reviewing them in relation to factors including our authorized returns on rate base, other returns on invested capital for projects of a similar nature, capital structure and credit ratings, among others. We will make adjustments to these discretionary expenditures as necessary based upon these factors.

Cash Flow from Financing Activities Our capitalization and financing strategy is intended to ensure that we are properly capitalized with the appropriate mix of equity and debt securities. This strategy includes active management of the percentage of total debt relative to total capitalization, appropriate mix of debt with fixed to floating interest rates (our variable debt target is 20% to 45% of total debt), as well as the term and interest rate profile of our debt securities.

On May 4, 2011, we entered into interest rate swaps with an aggregate notional amount of $250 million to effectively convert a portion of our $300 million 6.4% fixed-rate senior notes that mature July 2016 to a variable-rate obligation. As of December 31, 2011, we also held forward-starting interest rate swaps totaling $90 million that were redesignated as cash flow hedges upon the close of the merger. Under the terms of the swaps, we agree to pay a fixed swap rate and receive a floating rate based on LIBOR.

As of December 31, 2011, our variable-rate debt was $1.7 billion, or 36%, of our total debt, compared to $892 million, or 33%, as of December 31, 2010. This increase was primarily due to increased commercial paper borrowings as of year-end and the $250 million interest rate swaps, both of which increased our ratio of variable-rate debt. As of December 31, 2011, our commercial paper borrowings of $1.3 billion were 80% higher than the same time last year, primarily a result of the additional short-term debt that we assumed from the Nicor merger and higher working capital requirements. For more information on our debt, see Note 8 to our consolidated financial statements under Item 8 herein.

Our cash provided by financing activities was $933 million in 2011 compared to cash used of $86 million in 2010. The increase in net cash flow provided by financing activities of $1.0 billion was primarily due to our $1.3 billion of long-term debt issued, discussed below, and increased commercial paper borrowings of $91 million in 2011 compared to 2010. This was partially offset by payment for a senior note maturity of $300 million, decreased distribution to the noncontrolling interest of $11 million and increased dividends paid on common shares of $15 million.

Short-term Debt Our short-term debt as of December 31, 2011 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 [3][4]	$ 869	$324	$ —	$1,179
Commercial paper - Nicor Gas [5]	452	456	410	514
Senior notes	15	20	—	300
Capital leases	2	2	2	2
Term loan facility [3]	—	12	—	150
Total short-term debt	$1,338	$814	$412	$2,145

[1] As of December 31, 2011.

[2] For the year ended December 31, 2011, with the exception of the Nicor Gas commercial paper program, which is for the period December 10, 2011 – December 31, 2011. 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.

[3] During 2011, our short-term debt balances were impacted by our $300 million senior notes, which matured in January 2011. These senior notes were initially repaid with a $150 million funding under our Term Loan Facility and borrowings under our AGL Capital commercial paper program. In February 2011, the Term Loan Facility was repaid through additional AGL Capital commercial paper borrowings at which time the Term Loan Facility expired.

[4] During 2011, we completed $1,275 million in senior note offerings to repay our maturing long-term debt of $300 million and for the approximate $980 million in cash payments made for the Nicor merger consideration. Prior to the closing of the merger, a portion of the proceeds were used to reduce outstanding AGL Capital commercial paper.

[5] We assumed approximately $424 million in commercial paper borrowings as of the closing of the Nicor merger.

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. Our year-end short-term debt outstanding and our largest short-term debt balance outstanding were significantly higher than our average short-term debt outstanding during 2011 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.

Additionally, increasing natural gas commodity prices can have a significant impact on our commercial paper borrowings. Based on current natural gas prices and our expected injection plan, a $1 increase or decrease per thousand cubic feet of natural gas could result in a $200 million change of working capital requirements during the peak of the Heating Season. This range is sensitive to the timing of storage injections and withdrawals, collateral requirements and our portfolio position.

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, 2011, we had no outstanding borrowings under either of these facilities. SouthStar's five-year $75 million unsecured credit facility expired in November 2011.

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 approximately $2.2 billion of committed balances and all have investment grade credit ratings as of December 31, 2011. 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, 2011, 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, gas facility revenue bonds and capital leases.

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

	Issuance Date	Amount (in millions)	Term (in years)	Interest rate
Senior notes[1]	March 2011	$500	30	5.9%
Senior notes[2]	September 2011	$200	30	5.9%
Senior notes[2]	September 2011	$300	10	3.5%
Senior notes – Series A[2]	October 2011	$120	5	1.9%
Senior notes – Series B[2]	October 2011	$155	7	3.5%
Gas facility revenue bonds[3]	October 2010	$160	11 – 21	reset daily
Senior notes[4]	August 2009	$300	10	5.25%

[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 to pay a portion of 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.

[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.

[4] The net proceeds were used to repay a portion of our commercial paper.

Noncontrolling Interest We recorded cash distributions for SouthStar's dividend distributions to Piedmont of $16 million in 2011, $27 million in 2010 and $20 million in 2009 in our Consolidated Statement of Cash Flows as financing activities. The primary reason for the reduction in the distribution to Piedmont during the current year is due to our increased ownership percentage in SouthStar in 2010. The 2010 distribution was paid on 2009 earnings.

Dividends on Common Stock Our common stock dividend payments were $148 million in 2011, $133 million in 2010 and $127 million in 2009. The increases were generally the result of annual dividend increases 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. 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.

In addition, in conjunction with the Nicor merger we issued 38.2 million shares of AGL Resources common stock, which is the same class as our previously issued common stock and receives dividends at the same rate as the shares issued prior to the merger. Our common stock outstanding totaled approximately 117.0 million shares at December 31, 2011.

Treasury Shares In February 2006, our Board of Directors authorized a plan to purchase up to 8 million shares of our outstanding common stock over a five-year period. These purchases are intended principally to offset share issuances under our employee and non-employee director incentive compensation plans and our dividend reinvestment and stock purchase plans. Stock purchases under this program may be made in the open market or in private transactions at times and in amounts that we deem appropriate. There is no guarantee as to the exact number of common shares that we will purchase, and we can terminate or limit the program at any time. This program expired in January 2011.

For the year ended December 31, 2011, we purchased 65,250 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 years ended December 31, 2010 and 2009, we did not purchase shares of our common stock. We currently anticipate holding the purchased shares as treasury shares. For more information on our common share repurchases see Item 5 "Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities."

Shelf Registration On August 17, 2010, we filed a shelf registration with the SEC, which expires in 2013. Debt securities and related guarantees issued under the shelf registration will be issued by AGL Capital under an indenture dated as of February 20, 2001, as supplemented and modified, as necessary, among AGL Capital, AGL Resources and The Bank of New York Mellon Trust Company, N.A., as trustee. The indenture provides for the issuance from time to time of debt securities in an unlimited dollar amount and an unlimited number of series, subject to our 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 a capacity of $225 million with the SEC, which expires in March, 2012. First mortgage bonds issued under the shelf registration will be issued by Nicor Gas under an indenture dated as of January 1, 1954, as supplemented and modified, as necessary, among Northern Illinois Gas Company doing business as Nicor Gas Company and The Bank of New York Mellon Trust Company, N.A., as trustee. At December 31, 2011, Nicor Gas had the capacity to issue approximately $480 million of additional first mortgage bonds under the terms of its indenture.

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 our operating and financing activities that are reasonably likely to have a material effect on liquidity or the availability of requirements for capital resources. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements. These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related revenue-producing activities. Contingent financial commitments represent obligations that become payable only if certain predefined events occur, such as financial guarantees, and include the nature of the guarantee and the maximum potential

amount of future payments that could be required of us as the guarantor. The following table illustrates our expected future contractual obligation payments such as debt and lease agreements, and commitments and contingencies as of December 31, 2011.

In millions	Total	2012	2013	2014	2015	2016	2017 & thereafter
Recorded contractual obligations:							
Long-term debt[1]	$3,431	$ —	$225	$ —	$200	$545	$2,461
Short-term debt[2]	1,338	1,338	—	—	—	—	—
Pipeline replacement program costs[3]	276	131	145	—	—	—	—
Environmental remediation liabilities[3]	327	37	66	55	45	32	92
Total	$5,372	$1,506	$436	$ 55	$245	$577	$2,553
Unrecorded contractual obligations and commitments:[4][9][10]							
Pipeline charges, storage capacity and gas supply[5]	$2,263	$ 781	$494	$269	$164	$ 85	$ 470
Interest charges[6]	2,581	169	161	158	149	137	1,807
Operating leases[7]	220	32	25	20	19	18	106
Asset management agreements[8]	26	11	9	3	2	1	—
Standby letters of credit, performance/surety bonds[9]	22	18	4	—	—	—	—
Other	14	5	3	2	2	2	—
Total	$5,126	$1,016	$696	$452	$336	$243	$2,383

[1] Excludes the $99 million step up to fair value of first mortgage bonds, $18 million unamortized debt premium and $13 million interest rate swaps fair value adjustment.

[2] Includes current portion of long-term debt of $15 million which matures in June 2012.

[3] Includes charges recoverable through rate rider mechanisms.

[4] In accordance with GAAP, these items are not reflected in our Consolidated Statements of Financial Position.

[5] 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 67 Bcf at floating gas prices calculated using forward natural gas prices as of December 31, 2011, and is valued at $222 million. As we do for other subsidiaries, we provide guarantees to certain gas suppliers for SouthStar in support of payment obligations.

[6] Floating rate interest charges are calculated based on the interest rate as of December 31, 2011 and the maturity date of the underlying debt instrument. As of December 31, 2011, we have $61 million of accrued interest on our Consolidated Statements of Financial Position that will be paid in 2012.

[7] 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.

[8] Represent fixed-fee minimum payments for Sequent's affiliated asset management agreements.

[9] We provide guarantees to certain municipalities and other agencies and certain gas suppliers of SouthStar in support of payment obligations.

[10] Based on the current funding status of the plans, we would be required to make a minimum contribution to our pension plans of approximately $36 million in 2012. We may make additional contributions in 2012.

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

On September 30, 2011, Nicor Gas signed an agreement to purchase approximately 25 Bcf of SNG annually from one of the proposed facilities for a 10-year term beginning as early as 2015. The price of the SNG under this contract could potentially be significantly more than market price. The counterparty has announced plans to construct a 60 Bcf per year coal gasification plant in southern Illinois.

On October 11, 2011, the IPA approved the form of a draft 30-year contract for the purchase by us of approximately 20 Bcf per year of SNG from the second proposed plant beginning as early as 2018. In November 2011, Nicor Gas 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 Illinois Commission issued an order on January 10, 2012 approving a final form of contract for the second plant. The final form of contract approved by the Illinois Commission modified the draft contract submitted by the IPA in various respects. Both we and the developer of the plant have filed applications for rehearing with the Illinois Commission seeking changes to the final form of contract it approved.

The price of the SNG that may be produced from both of the coal gasification plants may significantly exceed market prices and is dependent upon a variety of factors, including plant construction costs, and is currently not estimable. Illinois laws provided that prices paid for SNG purchase from the plants are to be considered prudent and not subject to review or disallowance by the Illinois Commission. For additional information regarding the SNG plant legislation see Note 11 to our consolidated financial statements under Item 8 herein.

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 $291 million as of December 31, 2011 and $9 million as of December 31, 2010. In addition, we recorded a regulatory liability of $19 million as of December 31, 2011 and $6 million as of December 31, 2010 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 2011, we contributed $56 million to our qualified pension plans. In 2010, we contributed $31 million to these qualified pension plans. Based on the current funding status of these plans, we would be required to make a minimum contribution to the plans of approximately $36 million in 2012. We may make additional contributions in 2012 in order to preserve the current level of benefits under these plans and in accordance with the funding requirements of the Pension Protection Act.

Critical Accounting Policies and Estimates

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

We believe that of our significant accounting policies, described in Note 2 to our consolidated financial statements under Item 8 herein, the following policies represent those that may involve a higher degree of uncertainty, judgment and complexity; these include Regulatory Infrastructure Program Liabilities, Environmental Remediation Liabilities, Derivatives and Hedging Activities, Goodwill and Intangible Assets, Contingencies, Pension and Other Retirement Plans and Income Taxes.

Regulatory Infrastructure Program Liabilities

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

By order of the Georgia Commission, our wholly owned subsidiary, Atlanta Gas Light began a pipeline replacement program to replace all bare steel and cast iron pipe in its system by December 2013. The order provides for recovery of all prudent costs incurred in the performance of the program, which Atlanta Gas Light has recorded as a regulatory asset. Atlanta Gas Light will recover from end-use customers, through billings to Marketers, the costs related to the program net of any cost savings from the program. All such amounts will be recovered through a combination of straight-fixed-variable rates and a pipeline replacement revenue rider. The regulatory asset has two components (i) the costs incurred to date that have not yet been recovered through rate riders, and (ii) the future expected costs to be recovered through rate riders.

The determination of future expected costs associated with our pipeline replacement program liabilities involves judgment. To the extent that circumstances associated with regulatory balances change, the regulatory balances are adjusted accordingly. Factors that must be considered in estimating the future expected costs are:

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

We recorded a long-term liability of $145 million as of December 31, 2011 and $166 million as of December 31, 2010, which represented engineering estimates for remaining capital expenditure costs in the pipeline replacement program. As of December 31, 2011, we had recorded a current liability of $131 million, representing expected pipeline replacement program expenditures for the next 12 months. We report these estimates on an undiscounted basis. If Atlanta Gas Light's pipeline replacement program expenditures, subject to future recovery, were $10 million higher or lower its incremental expected annual revenues would have changed by approximately $1 million. Details of our regulatory assets and liabilities are discussed in Note 2 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. Additionally, we owned and operated a number of MGP sites at which hazardous substances may be present. In accordance with GAAP, we have established reserves for environmental remediation obligations when it is probable that a liability exists and the amount or range of amounts can be reasonably estimated. We historically reported estimates of future environmental remediation costs based on probabilistic models of potential costs. We presently report estimates of future remediation costs on an undiscounted basis. These estimates contain various engineering uncertainties, and we continuously attempt to refine these estimates. However, we have not yet performed these probabilistic models for all of our sites in Illinois, which will be completed in 2012.

In Georgia and Florida, we have confirmed 14 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 26 sites in Illinois for which we may have some responsibility. 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.

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.

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

In millions	Cost estimate range[1]	Amount recorded	Expected costs over next twelve months
Illinois	$134 – $216	$134	$19
Georgia and Florida	42 – 98	58	7
New Jersey	124 – 174	124	9
North Carolina	10 – 16	11	2
Total	$310 – $504	$327	$37

[1] Our ERC liabilities are customarily reported estimates of future remediation costs for our former operating sites that are contaminated based on probabilistic models of potential costs and on an undiscounted basis. However, we have not yet performed these probabilistic models for all of our sites in Illinois, which will be completed in 2012.

Beyond 2012, these costs cannot be estimated and considerable variability remains in available estimates. Details of our environmental remediation costs are discussed in Note 2 and Note 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 are 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 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 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 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.

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 levels. The determination of the fair value of our derivative instruments incorporates various factors required under the guidance. These factors include:

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

We have recorded derivative instrument assets of $314 million at December 31, 2011 and $228 million at December 31, 2010. Additionally, we have recorded derivative liabilities of $110 million at December 31, 2011 and $48 million at December 31, 2010. We recorded gains on our Consolidated Statements of Income of $24 million in 2011 and losses of $46 million in 2010 and $15 million in 2009.

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".

Goodwill and Intangible Assets

Goodwill is the excess of the purchase price over the fair value of identifiable net assets acquired in business combinations. Our goodwill assets increased from $418 million to $1.8 billion and our intangible assets increased from $2 million to $105 million as a result of the Nicor merger. Our intangible assets at December 31, 2010 were $3 million, but as a result of amortization during 2011 were $2 million as of the date of the Nicor merger. The fair values of intangible assets were assigned to the trade names and customer relationships at Nicor's unregulated operations using a combination of the valuation approaches, including cost savings, multi-period excess earnings and relief from royalty approaches.

In accordance with the authoritative guidance, we evaluate our goodwill balances for impairment on an annual basis or more frequently if impairment indicators arise. These indicators include, but are not limited to, a significant change in operating performance, the business climate, legal or regulatory factors, or a planned sale or disposition of a significant portion of the business. We test goodwill impairment utilizing a fair value approach at a reporting unit level which generally equates to our operating segments as discussed in Note 13 to our consolidated financial statements under Item 8 herein. An impairment charge is recognized if the carrying value of a reporting unit's goodwill exceeds its fair value.

Our goodwill impairment analysis for the years ended December 31, 2011 and 2010 indicated that the fair value of each reporting unit is substantially in excess of carrying value, and are not at risk of failing step one of the impairment evaluation. As a result, we did not recognize any goodwill impairment charges and do not anticipate taking goodwill impairment charges in the foreseeable future. Goodwill recorded from the Nicor merger totaled $1.4 billion, of which $1.2 billion was assigned to distribution operations, $124 million to retail operations, $77 million to cargo shipping, $2 million to midstream operations, $2 million to wholesale services and $8 million to other. For additional information see Note 3 to our consolidated financial statements under Item 8 herein.

Intangible assets from the Nicor merger totaled to $103 million, of which $85 million was assigned to retail operations and $18 million to cargo shipping. In accordance with the authoritative guidance, we amortize intangible assets over their useful lives as we currently have no indefinite-lived intangible assets. These assets are reviewed for impairment when indicators arise. When such events or circumstances are present, we assess the

recoverability of long-lived assets by determining whether the carrying value will be recovered through the expected future cash flows. In the event the sum of the expected future cash flows resulting from the use of the asset is less than the carrying value of the asset, an impairment loss equal to the excess of the asset's carrying value over its fair value is recorded. No impairment has been recognized.

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

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 certain market indices, including the Citigroup Pension Liability rate, the Moody's Corporate AA long-term bond rate, other high-grade bond indices and a single equivalent discount rate, which is derived by applying the appropriate spot rates based on high quality (AA or better) corporate bonds, to the forecasted future cash flows in each year.

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 than 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. Plan assets for the Nicor Gas pension plan are measured at fair value. For the AGL pension plan, market performance also effects our market-related value of plan assets (MRVPA), which is a calculated value and differs from the actual market value of plan assets. The MRVPA recognizes differences between the actual market value and expected market value of our plan assets and is determined by our actuaries using a five-year moving weighted average methodology. Gains and losses on plan assets are spread through the MRVPA based on the five-year moving weighted average methodology, which affects the expected return on plan assets component of pension expense.

In addition, differences between actuarial assumptions and actual plan results are deferred and amortized into cost when the accumulated differences exceed 10% of the greater of the projected benefit obligation (PBO) or the MRVPA for the AGL pension plan and fair value of the assets for the Nicor Gas pension plan. If necessary, the excess is amortized over the average remaining service period of active employees.

During 2011, we recorded net periodic benefit costs of $22 million related to our defined pension and other retirement benefit plans. We estimate that in 2012, we will record net periodic pension and other retirement benefit costs in the range of $54 million to $57 million (net of capitalization), a $32 million to $35 million increase compared to 2011. Approximately $25 million to $27 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 to increase by $5 million to $7 million. 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 2012, our actuarial consultant assumed the following expected return on plan assets and discount rates.

	Pension plans	Other retirement plans
Discount rate	4.60%	4.50%
Expected long-term return on plan assets	8.25% – 8.50%	6.8% – 8.50%

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%	$ –/–	$(5) / 5
Discount rate	+/- 1%	(161) / 178	(6) / 6

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

Income Taxes

We account for income taxes in accordance with the authoritative guidance related to income taxes, which requires that deferred tax assets and liabilities be recognized using enacted tax rates for the effect of temporary differences between the book and tax basis of recorded assets and liabilities. The guidance also requires that deferred tax assets be reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset 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 audit in these jurisdictions. These audits can involve complex issues, which may require an extended period of time to resolve. We maintain a liability for the estimate of potential income tax exposure and in our opinion adequate provisions for income taxes have been made for all years.

We had a $3 million valuation allowance on $204 million of deferred tax assets as of December 31, 2011, reflecting the expectation that most of these assets will be realized. Our gross long-term deferred tax liability totaled $1,646 million at December 31, 2011. 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, 2011, we did not have a liability recorded for payment of interest and penalties associated with uncertain tax positions.

Accounting Developments

On May 12, 2011, the FASB issued authoritative guidance related to fair value measurements. The guidance expands the qualitative and quantitative disclosures for Level 3 significant unobservable inputs, permits the use of premiums and discounts to value an instrument if it is standard practice and limits best use valuation to non-financial assets and liabilities. This guidance will be effective for us beginning January 1, 2012. We do not expect the guidance to have a material impact on our consolidated financial statements.

On June 16, 2011, the FASB issued authoritative guidance related to comprehensive income. The guidance eliminates the option to present other comprehensive income in the Statements of Equity, but instead allows companies to elect to present net income and other comprehensive income in one continuous statement (Statements of Comprehensive Income) or in two consecutive statements. This guidance does not change any of the components of net income or other comprehensive income and earnings per

share will still be calculated based on net income. This guidance will be effective for us beginning January 1, 2012, and will not have a material impact on our consolidated financial statements.

On September 15, 2011, the FASB issued authoritative guidance related to goodwill impairment testing. The guidance provides us with the option to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If we determine that it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then performing the normally required two-step quantitative impairment test is unnecessary. However, if we conclude otherwise, we are then required to proceed with the quantitative testing. The guidance allows us to bypass the qualitative assessment for any reporting unit in any period and proceed directly to quantitative testing and resume performing the qualitative assessment in any subsequent period. This guidance is effective for us on January 1, 2012, but early adoption is permitted. We adopted the guidance early and relied upon a qualitative assessment when performing our annual impairment test in the fourth quarter of 2011.

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 is defined as the potential loss that we may incur as a result of changes in the fair value of natural gas. Interest rate risk results from our portfolio of debt and equity instruments that we issue to provide financing and liquidity for our business. Credit risk results from the extension of credit throughout all aspects of our business but is particularly concentrated at Atlanta Gas Light in distribution operations and in wholesale services. Our fuel price risk is primarily in cargo shipping, which 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. Unrealized changes in the fair value of these derivative instruments are deferred as regulatory assets or liabilities.

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 lock in economic margins (as spreads between wholesale and retail natural gas prices widen between periods) and thereby minimize its exposure to declining operating margins.

Wholesale Services 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 Central Valley and Golden Triangle Storage use derivative instruments to reduce their 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 the cavern (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, 2011 and 2010.

In millions	Derivative instruments average values[1] at December 31, 2011	2010
Asset	**$211**	$226
Liability	**76**	70

[1] Excludes cash collateral amounts.

In millions	Derivative instruments fair value netted with cash collateral at December 31, 2011	2010
Asset	**$314**	$228
Liability	**110**	48

The following tables illustrate the change in the net fair value of our derivative instruments during the twelve months ended December 31, 2011, 2010 and 2009, and provide details of the net fair value of contracts outstanding as of December 31, 2011, 2010 and 2009.

In millions	2011	2010	2009
Net fair value of derivative instruments outstanding at beginning of period	**$ 75**	$ 121	$ 65
Derivative instruments realized or otherwise settled during period	**(74)**	(117)	(54)
Net fair value of derivative instruments acquired during period	**(5)**	—	50
Change in net fair value of derivative instruments	**61**	71	60
Net fair value of derivative instruments outstanding at end of period	**57**	75	121
Netting of cash collateral	**147**	105	57
Cash collateral and net fair value of derivative instruments outstanding at end of period[1]	**$204**	$ 180	$178

[1] Net fair value of derivative instruments outstanding includes $3 million premium and associated intrinsic value at December 31, 2011, less than $1 million at December 31, 2010 and $2 million at December 31, 2009 associated with weather derivatives.

The sources of our net fair value at December 31, 2011, are as follows.

In millions	Prices actively quoted (Level 1)[1]	Significant other observable inputs (Level 2)[2]
Mature through 2012	$ (90)	$126
Mature 2013 – 2014	(15)	36
Mature 2015 – 2017	(2)	2
Total derivative instruments[3]	$(107)	$164

[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, 2011, 2010 and 2009 were less than $0.1 million and Sequent had the following VaRs.

In millions	2011	2010	2009
Period end	**$2.2**	$1.6	$2.4
12-month average	**1.6**	1.3	1.8
High	**3.1**	3.0	3.3
Low	**0.8**	0.7	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.

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 $1.7 billion of variable-rate debt outstanding at December 31, 2011, a 100 basis point change in market interest rates would have resulted in an increase in pretax interest expense of $17 million on an annualized basis.

We have $300 million of 6.4% senior notes due in July 2016. In May 2011, we entered into interest rate swaps related to these senior notes to effectively convert $250 million from a fixed rate to a variable rate obligation. The interest rate resets quarterly based on LIBOR plus 3.9%.

As of December 31, 2011, we also held forward-starting interest rate swaps totaling $90 million that were redesignated as cash flow hedges upon the close of the merger. Under the terms of the swaps, we agree to pay a fixed swap rate and receive a floating rate based upon LIBOR.

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). Any gain or loss on these interest rate swaps are deferred in accumulated other comprehensive income until settlement, at which point they are 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 the year, with exposure at its lowest in the nonpeak summer months and highest in the peak winter months. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. These retail functions include customer service, billing, collections, and the purchase and sale of the natural gas commodity. The provisions of Atlanta Gas Light's tariff allow Atlanta Gas Light to obtain security support in an amount equal to a minimum of two times a Marketer's highest month's estimated bill from Atlanta Gas Light. For 2011, the four largest Marketers based on customer count, which includes SouthStar, accounted for approximately 30% of our consolidated operating margin and 38% 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, limits its exposure to any one 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, 2011 for agreements with such features, our distribution operations derivative instruments with liability fair values totaled approximately $52 million for which we had posted $17 million of 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 approximately $33 million at December 31, 2011.

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 a review of publicly available financial statements and review of 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 our 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 its 30-day receivable exposure plus forward exposure. As of December 31, 2011, excluding $11 million of customer deposits, our top 20 counterparties represented approximately 60% of the total counterparty exposure of $504 million, derived by adding together the top 20 counterparties' exposures, exclusive of customer deposits, and dividing by the total of our counterparties' exposures.

As of December 31, 2011, our counterparties, or the counterparties' guarantors, had a weighted average S&P equivalent credit rating of BBB+, which is consistent with the prior year. The S&P equivalent credit rating is determined by a process of converting the lower of the S&P or Moody's ratings to an internal rating ranging from 9 to 1, with 9 being equivalent to AAA/Aaa by S&P and Moody's and 1 being D or Default by S&P and Moody's. A counterparty that does not have an external rating is assigned an internal rating based on the strength of the financial ratios of that counterparty. To arrive at the weighted average credit rating, each counterparty is assigned an internal ratio, which is multiplied by their credit exposure and summed for all counterparties. The sum is divided by the aggregate total counterparties' exposures, and this numeric value is then converted to an S&P equivalent. The following table shows our third-party natural gas contracts receivable and payable positions.

	As of December 31, Gross receivables	
In millions	**2011**	2010
Netting agreements in place:		
Counterparty is investment grade	**$395**	$515
Counterparty is non-investment grade	**23**	11
Counterparty has no external rating	**184**	260
No netting agreements in place:		
Counterparty is investment grade	**4**	2
Counterparty has no external rating	**1**	—
Amount recorded on Statements of Financial Position	**$607**	$788

	As of December 31, Gross payables	
In millions	**2011**	2010
Netting agreements in place:		
Counterparty is investment grade	**$255**	$341
Counterparty is non-investment grade	**47**	40
Counterparty has no external rating	**288**	363
No netting agreements in place:		
Counterparty is investment grade	**—**	—
Counterparty has no external rating	**—**	—
Amount recorded on Statements of Financial Position	**$590**	$744

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 its 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 $15 million at December 31, 2011, 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, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 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, 2011, 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.

As described in Management's Report on Internal Control Over Financial Reporting, management has excluded Nicor from its assessment of internal control over financial reporting as of December 31, 2011 because it was acquired by the Company in a purchase business combination during 2011. We have also excluded Nicor from our audit of internal control over financial reporting. Nicor is a wholly owned subsidiary whose total assets and total revenues represent 47% and 9%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2011.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Atlanta, Georgia
February 22, 2012

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.

On December 9, 2011, we completed our merger with Nicor. As permitted by the Securities and Exchange Commission, management has elected to exclude Nicor from management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2011. Assets and revenues of Nicor represent 47% and 9%, respectively, of our total assets and total revenues as reported in our consolidated financial statements as of and for the year ended December 31, 2011.

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, 2011, 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 22, 2012

/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

Consolidated Statements of Financial Position—Assets

In millions	As of December 31, 2011	2010
Current assets		
Cash and cash equivalents (Note 2)	**$ 69**	$ 24
Short-term investments (Note 2)	**53**	—
Receivables		
Energy marketing receivables	**607**	788
Gas	**364**	204
Unbilled revenues	**216**	173
Other	**112**	13
Less allowance for uncollectible accounts	**15**	16
Total receivables (Note 2)	**1,284**	1,162
Inventories		
Natural gas stored underground	**702**	607
Other	**48**	32
Total inventories (Note 2)	**750**	639
Derivative instruments – current portion (Note 2, Note 4 and Note 5)	**248**	182
Recoverable regulatory infrastructure program costs – current portion (Note 2)	**48**	48
Recoverable environmental remediation costs – current portion (Note 2 and Note 11)	**7**	7
Recoverable postretirement benefits – current (Note 2 and Note 6)	**29**	—
Prepaid expenses	**164**	66
Other current assets	**94**	38
Total current assets	**2,746**	2,166
Long-term assets and other deferred debits		
Property, plant and equipment	**9,779**	6,266
Less accumulated depreciation	**1,879**	1,861
Property, plant and equipment – net (Note 2)	**7,900**	4,405
Goodwill (Note 2 and Note 3)	**1,813**	418
Intangible assets (Note 2 and Note 3)	**105**	3
Recoverable regulatory infrastructure program costs (Note 2)	**305**	244
Recoverable environmental remediation costs (Note 2 and Note 11)	**351**	164
Recoverable postretirement benefits – long-term (Note 2 and Note 6)	**262**	—
Long-term investments (Note 2)	**128**	11
Derivative instruments (Note 2, Note 4 and Note 5)	**66**	46
Other	**237**	63
Total long-term assets and other deferred debits	**11,167**	5,354
Total assets	**$13,913**	$7,520

See Notes to Consolidated Financial Statements.

Consolidated Statements of Financial Position—Liabilities and Equity

In millions, except share amounts	As of December 31, 2011	2010
Current liabilities		
Energy marketing trade payable (Note 2)	**$ 590**	$ 744
Short-term debt (Note 8)	**1,323**	733
Current portion of long-term debt (Note 8)	**15**	300
Accounts payable – trade	**294**	178
Accrued regulatory infrastructure program costs – current portion (Note 2)	**131**	62
Customer credit balances and deposits	**152**	52
Accrued wages and salaries	**52**	51
Accrued taxes	**49**	48
Derivative instruments – current portion (Note 2, Note 4 and Note 5)	**99**	44
Accrued interest (Note 11)	**61**	40
Accrued natural gas costs (Note 2)	**53**	23
Accrued environmental remediation liabilities – current portion (Note 2 and Note 11)	**37**	14
Other current liabilities	**228**	143
Total current liabilities	**3,084**	2,432
Long-term liabilities and other deferred credits		
Long-term debt (Note 4 and Note 8)	**3,561**	1,671
Accumulated deferred income taxes (Note 2 and Note 12)	**1,445**	768
Accrued pension obligations (Note 4 and Note 6)	**238**	186
Accumulated removal costs (Note 2)	**1,321**	182
Accrued regulatory infrastructure program costs (Note 2)	**145**	166
Accrued environmental remediation liabilities (Note 2 and Note 11)	**290**	129
Accrued other retirement benefit costs (Note 4 and Note 6)	**320**	36
Derivative instruments (Note 2, Note 4 and Note 5)	**11**	4
Other long-term liabilities and other deferred credits	**159**	110
Total long-term liabilities and other deferred credits	**7,490**	3,252
Total liabilities and other deferred credits	**10,574**	5,684
Commitments, guarantees and contingencies (see Note 11)		
Equity		
Common shareholders' equity		
Common stock, $5 par value; 750 million shares authorized	**586**	391
Additional paid in capital	**1,989**	631
Retained earnings	**967**	943
Accumulated other comprehensive income (loss)	**(217)**	(150)
Treasury shares	**(7)**	(2)
Total common shareholders' equity (Note 9)	**3,318**	1,813
Noncontrolling interest (Note 10)	**21**	23
Total equity	**3,339**	1,836
Total liabilities and equity	**$13,913**	$7,520

See Notes to Consolidated Financial Statements.

Consolidated Statements of Income

In millions, except per share amounts	Years ended December 31, 2011	2010	2009
Operating revenues (Note 2)	**$2,338**	$2,373	$2,317
Operating expenses			
Cost of goods sold (Note 2)	**1,097**	1,164	1,142
Operation and maintenance	**490**	497	497
Depreciation and amortization (Note 2)	**186**	160	158
Nicor merger expenses (Note 3)	**68**	6	—
Taxes other than income taxes	**57**	46	44
Total operating expenses	**1,898**	1,873	1,841
Operating income	**440**	500	476
Other income (expense)			
Other (expense) income, net	**7**	(1)	9
Interest expenses, net	**(136)**	(109)	(101)
Total other expense	**(129)**	(110)	(92)
Earnings before income taxes	**311**	390	384
Income tax expenses (Note 12)	**125**	140	135
Net income	**186**	250	249
Less net income attributable to the noncontrolling interest (Note 10)	**14**	16	27
Net income attributable to AGL Resources Inc.	**$ 172**	$ 234	$ 222
Per common share data (Note 2)			
Basic earnings per common share attributable to AGL Resources Inc. common shareholders (Note 2)	**$ 2.14**	$ 3.02	$ 2.89
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders (Note 2)	**$ 2.12**	$ 3.00	$ 2.88
Cash dividends declared per common share	**$ 1.90**	$ 1.76	$ 1.72
Weighted average number of common shares outstanding (Note 2)			
Basic	**80.4**	77.4	76.8
Diluted	**80.9**	77.8	77.1

See Notes to Consolidated Financial Statements.

Consolidated Statements of Comprehensive Income

In millions	Years ended December 31, 2011	2010	2009
Comprehensive income attributable to AGL Resources Inc. (net of tax)			
Net income attributable to AGL Resources Inc.	**$172**	$234	$222
Other comprehensive income (loss),net of tax			
Retirement plans (Note 4 and Note 6)			
Unrealized (loss) gain arising during the period	**(65)**	(28)	17
Cash flow hedges (Note 5)			
Derivative instruments unrealized losses arising during the period	**(5)**	(14)	(12)
Reclassification of realized derivative losses to net income	**3**	9	13
Other comprehensive (loss) income	**(67)**	(33)	18
Comprehensive income (Note 9)	**$105**	$201	$240
Comprehensive income (loss) attributable to noncontrolling interest (net of tax)			
Net income attributable to noncontrolling interest (Note 9)	**$ 14**	$ 16	$ 27
Cash flow hedges (Note 5)			
Derivative instruments unrealized losses arising during the period	**(1)**	(1)	(7)
Reclassification of realized derivative losses to net income	**1**	2	7
Other comprehensive income	**—**	1	—
Comprehensive income (Note 9)	**$ 14**	$ 17	$ 27
Total comprehensive income (net of tax)			
Net income	**$186**	$250	$249
Other comprehensive income (loss),net of tax			
Retirement benefit plans (Note 4 and Note 6)			
Unrealized (loss) gain arising during the period	**(65)**	(28)	17
Cash flow hedges (Note 5)			
Derivative instruments unrealized losses arising during the period	**(6)**	(15)	(19)
Reclassification of realized derivative losses to net income	**4**	11	20
Other comprehensive (loss) income	**(67)**	(32)	18
Comprehensive income (Note 9)	**$119**	$218	$267

See Notes to Consolidated Financial Statements.

Consolidated Statements of Equity

In millions, except per share amounts	AGL Resources Inc. Shareholders							
	Common stock Shares	Common stock Amount	Additional paid-in-capital	Retained earnings	Accumulated other comprehensive loss	Treasury shares	Noncontrolling interest	Total
Balance as of December 31, 2008	76.9	$390	$ 676	$ 763	$(134)	$(43)	$ 32	$1,684
Net income	—	—	—	222	—	—	27	249
Other comprehensive income (Note 9)	—	—	—	—	18	—	—	18
Dividends on common stock ($1.72 per share)	—	—	—	(132)	—	5	—	(127)
Distributions to noncontrolling interests (Note 10)	—	—	—	—	—	—	(20)	(20)
Issuance of treasury shares (Note 9)	0.6	—	(4)	(5)	—	17	—	8
Stock-based compensation expense (net of tax) (Note 7)	—	—	7	—	—	—	—	7
As of December 31, 2009	77.5	$390	$ 679	$ 848	$(116)	$(21)	$ 39	$1,819
Net income	—	—	—	234	—	—	16	250
Other comprehensive (loss) income (Note 9)	—	—	—	—	(33)	—	1	(32)
Dividends on common stock ($1.76 per share)	—	—	—	(136)	—	3	—	(133)
Purchase of additional 15% ownership interest in SouthStar (Note 10)	—	—	(51)	—	(1)	—	(6)	(58)
Distributions to noncontrolling interests (Note 10)	—	—	—	—	—	—	(27)	(27)
Purchase of treasury shares (Note 9)	(0.2)	—	—	—	—	(7)	—	(7)
Issuance of treasury shares (Note 9)	0.7	1	(5)	(3)	—	22	—	15
Stock-based compensation expense (net of tax) (Note 7)	—	—	8	—	—	1	—	9
As of December 31, 2010	78.0	$391	$ 631	$ 943	$(150)	$ (2)	$ 23	$1,836
Net income	**—**	**—**	**—**	**172**	**—**	**—**	**14**	**186**
Other comprehensive (loss) income (Note 9)	**—**	**—**	**—**	**—**	**(67)**	**—**	**—**	**(67)**
Dividends on common stock ($1.90 per share)	**—**	**—**	**—**	**(148)**	**—**	**—**	**—**	**(148)**
Distributions to noncontrolling interests (Note 10)	**—**	**—**	**—**	**—**	**—**	**—**	**(16)**	**(16)**
Benefit, dividend reinvestment and stock purchase plans	**0.8**	**4**	**18**	**—**	**—**	**(3)**	**—**	**19**
Purchase of treasury shares (Note 9)	**—**	**—**	**—**	**—**	**—**	**(2)**	**—**	**(2)**
Issuance of shares for Nicor merger (Note 3)	**38.2**	**191**	**1,332**	**—**	**—**	**—**	**—**	**1,523**
Stock-based compensation expense (net of tax) (Note 7)	**—**	**—**	**8**	**—**	**—**	**—**	**—**	**8**
As of December 31, 2011	**117.0**	**$586**	**$1,989**	**$ 967**	**$(217)**	**$ (7)**	**$ 21**	**$3,339**

See Notes to Consolidated Financial Statements.

Consolidated Statements of Cash Flows

In millions	Years ended December 31, 2011	2010	2009
Cash flows from operating activities			
Net income	**$ 186**	$ 250	$ 249
Adjustments to reconcile net income to net cash flow provided by operating activities			
Depreciation and amortization (Note 2)	**186**	160	158
Deferred income taxes (Note 12)	**214**	92	105
Change in derivative instrument assets and liabilities (Note 4 and Note 5)	**(24)**	(2)	11
Changes in certain assets and liabilities			
Energy marketing receivables and trade payables, net (Note 2)	**27**	47	(81)
Inventories (Note 2)	**158**	33	(9)
Accrued expenses	**(77)**	7	19
Trade payables, other than energy marketing	**(70)**	(12)	1
Accrued natural gas costs (Note 2)	**(3)**	(14)	24
Receivables, other than energy marketing (Note 2)	**45**	(26)	108
Prepaid expenses	**(98)**	6	(21)
Other – net	**(93)**	(15)	28
Net cash flow provided by operating activities	**451**	526	592
Cash flows from investing activities			
Acquisition of Nicor Inc, net of cash acquired (Note 3)	**(912)**	–	–
Expenditures for property, plant and equipment (Note 2)	**(427)**	(510)	(476)
Proceeds from the disposition of assets	**–**	73	–
Other	**–**	(5)	–
Net cash flow used in investing activities	**(1,339)**	(442)	(476)
Cash flows from financing activities			
Issuances of senior notes (Note 8)	**1,014**	–	297
Payment of senior notes (Note 8)	**(300)**	–	–
Issuances of private placement bonds (Note 8)	**275**	–	–
Proceeds from term loan facility	**150**	–	–
Payments of term loan facility	**(150)**	–	–
Benefit, dividend reinvestment and stock purchase plan	**19**	8	8
Net payments and borrowings of short-term debt	**91**	131	(264)
Issuances of variable rate gas facility revenue bonds (Note 8)	**–**	160	–
Payments of gas facility revenue bonds (Note 8)	**–**	(160)	–
Purchase of treasury shares (Note 9)	**(2)**	(7)	–
Distribution to noncontrolling interest (Note 10)	**(16)**	(27)	(20)
Purchase 15% ownership in SouthStar from Piedmont (Note 10)	**–**	(58)	–
Dividends paid on common shares (Note 9)	**(148)**	(133)	(127)
Net cash flow provided by (used in) financing activities	**933**	(86)	(106)
Net increase (decrease) in cash and cash equivalents	**45**	(2)	10
Cash and cash equivalents at beginning of period	**24**	26	16
Cash and cash equivalents at end of period	**$ 69**	$ 24	$ 26
Cash paid during the period for			
Interest	**$ 116**	$ 107	$ 93
Income taxes	**$12**	$ 58	$ 50
Non cash transactions			
Merger with Nicor, common stock issued 38.2 million shares, value	**$ 1,523**	$ –	$ –

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 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.

Business Combinations

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. See Note 3 for additional information.

Basis of Presentation

Our consolidated financial statements as of and for the period ended December 31, 2011 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.

Note 2 Significant Accounting Policies and Methods of Application

Cash and Cash Equivalents

Our cash and cash equivalents consist primarily of cash on deposit, money market accounts and certificates of deposit 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 included in its 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.

Investments

Our investments in marketable securities are categorized at the date of acquisition as trading, held-to-maturity, or available-for-sale. Trading securities, which include money market funds, are carried at fair value and are classified as current assets unless held to satisfy a long-term obligation. We classify money market funds held by our non-United States subsidiaries as short-term investments and all others are classified as cash equivalents. Debt securities are categorized as held-to-maturity when our intent and ability is to hold the securities to maturity. Held-to-maturity securities are included in either short-term or long-term investments based upon their contractual maturity date. We carry held-to-maturity securities at

amortized cost, which approximates fair value. Available-for-sale securities are carried at fair value, with unrealized gains and losses, net of tax, reported in common equity as a component of accumulated OCI. Available-for-sale securities are classified as noncurrent assets unless the intent is to sell the security within 12 months. The specific identification method is used to determine realized gains or losses on the sale of marketable securities. Investments in equity securities that do not have a readily determinable fair value and do not qualify for the equity method are carried at cost.

Our investments in debt and equity securities at December 31 are as follows:

In millions	2011
Money market funds	**$59**
Corporate bonds	**6**
Other investments	**7**
Total	**$72**

Investments in debt and equity securities are classified on the Consolidated Statements of Financial Position at December 31 as follows:

In millions	2011
Cash equivalents	**$ 9**
Short-term investments	**53**
Long-term investments	**10**
Total	**$72**

Investments categorized as trading (including money market funds) totaled $59 million at December 31, 2011.

Corporate bonds and certain other investments are categorized as held-to-maturity. The contractual maturities of the held-to-maturity investments at December 31, 2011 are as follows:

	Years to maturity			
In millions	Less than 1 year	1-5 years	5-10 years	Total
Held-to-maturity investments	$2	$5	$1	$8

Our investments also include certain investments, including certificates of deposit and bank accounts, maintained to fulfill statutory or contractual requirements. These investments totaled $3 million at December 31, 2011. In addition, we hold a $2 million investment in a port facility development venture carried at cost. Gains or losses included in earnings resulting from the sale of investments were not significant.

Inventories

Except for Nicor Gas, distribution operations records natural gas stored underground at WACOG. Nicor Gas' inventory is carried at cost on a last-in-first-out (LIFO) basis. For our wholesale services and retail 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 2011, the estimated replacement cost of Nicor Gas' inventory at December 31, 2011 exceeded the LIFO cost by $189 million. During the 22 days of December 2011, Nicor Gas had an immaterial LIFO liquidation.

Our retail operations and wholesale services 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 and wholesale services charged LOCOM adjustments to cost of goods sold, to reduce the value of their inventories to market value in the following amounts.

In millions	2011	2010	2009
Retail operations	**$ 5**	$—	$6
Wholesale services	**31**	8	8

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 wholesale services to net receivables and payables by counterparty. Wholesale services also nets across product lines and against cash collateral, provided the master netting and cash collateral agreements include such provisions. The amounts due from or owed to wholesale services' counterparties are settled net, but 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, 2011 and December 31, 2010, 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, 2011, excluding $11 million of customer deposits.

Dollars in millions	Total[1]	# of top counterparties	Concentration risk %
Credit exposure	$304	20	60%

[1] Our counterparties or the counterparties' guarantors had a weighted average S&P equivalent rating of BBB+ at December 31, 2011.

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

The carrying values of cash and cash equivalents, receivables, short and long-term investments, derivative assets and liabilities, accounts payable, short-term debt, retirement plan assets, other current assets and liabilities and accrued interest approximate fair value. 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 market place. As we aggregate our disclosures by counterparty, the underlying transactions for a given counterparty may be a combination of exchange-traded

derivatives and values based on other sources. Instruments in this category include shorter tenor exchange-traded and non-exchange-traded derivatives such as OTC forwards and options 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. Our Level 3 assets and liabilities are primarily related to our retirement plan assets as described in Note 4 and Note 6. However, we have nonretirement plan Level 3 assets and liabilities that are described further in Note 3, Note 4 and Note 5. 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. 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 if the market for a financial asset is inactive and a transaction is not distressed. Currently, this authoritative guidance does not affect us, as our derivative instruments are traded in active markets.

Derivative Instruments

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 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.

Under authoritative guidance related to derivatives and hedging we have elected to net derivative assets and liabilities under master netting arrangements. With that election, we are also required to offset, on our Consolidated Statements of Financial Position cash collateral held in our broker accounts with the associated fair value of the instruments in the accounts. See Note 5 for additional information about our cash collateral.

Natural Gas Derivative Instruments

The fair value of natural gas derivative instruments we use to manage exposures arising from changing natural gas prices reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains or losses on open contracts. We use external market quotes and indices to value substantially all of our derivative 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. In accordance with the authoritative guidance related to derivatives and hedging, such derivative transactions are accounted for at fair value each reporting period in our Consolidated Statements of Financial Position. In accordance with regulatory requirements realized gains and losses related to these derivatives are reflected in natural gas costs and ultimately included in billings to customers. 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.

Nicor Gas also enters into swap agreements 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 use in its operations. These derivative instruments are carried at fair value. To the extent hedge accounting is not elected, changes in such fair values are immediately recorded in the current period as operation and maintenance expense.

Retail Operations We have designated a portion of these 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 as the settlement of the underlying hedged item.

We currently have minimal hedge ineffectiveness defined as when the gains or losses on the hedging instrument do not offset the losses or gains on the hedged item. This cash flow hedge ineffectiveness is recorded in cost of 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 under the authoritative guidance related to derivatives and hedging 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 under the authoritative guidance related to financial instruments. These weather derivative instruments do not qualify for accounting hedge designation and changes in value are reflected in cost of goods sold on our Consolidated Statements of Income.

Wholesale Services We purchase natural gas for storage when the difference in the current market price we pay to buy and transport natural gas plus the cost to store the natural gas is less than the market price we can receive in the future, resulting in a positive net operating margin. We use NYMEX futures contracts and other OTC derivatives to sell natural gas at that future price to substantially lock in the operating margin we will ultimately realize when the stored natural gas is sold. These futures contracts meet the definition of derivatives under the authoritative guidance related to derivatives and hedging and are accounted for at fair value in our Consolidated Statements of Financial Position, with changes in fair value recorded in our Consolidated Statements of Income in the period of change. These futures contracts are not designated as hedges as may be permitted under the guidance.

The purchase, transportation, storage and sale of natural gas are accounted for on a weighted average cost or accrual basis, as appropriate, rather than on the fair value basis we utilize for the derivatives used to mitigate the natural gas price risk associated with our storage portfolio. This difference in accounting can result in volatility in our reported earnings, even though the economic margin is essentially unchanged from the date the transactions were consummated.

Midstream Operations During the construction of the storage caverns, Golden Triangle Storage uses derivative instruments to reduce its exposure to the risk of changes in the price of natural gas that will be purchased in future periods for pad gas.

Golden Triangle Storage's derivative instruments have been used to economically hedge operational purchases and sales and do not qualify as cash flow hedges. The pad gas is considered to be a component of the storage cavern's construction costs; as a result, any derivative gains or losses arising from the cash flow hedges will remain in accumulated OCI until the pad gas is sold, which will not occur until the storage caverns are decommissioned. The fair value of these derivative instruments currently have minimal hedge ineffectiveness which is recorded in cost of goods sold in our Consolidated Statements of Income in the period in which it occurs. Golden Triangle Storage began entering into these derivative transactions during 2009.

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, 2011 and 2010 is provided in the following table.

In millions	***2011***	*2010*
Transmission and distribution	**$7,579**	$4,955
Shipping vessels and containers	**146**	n/a
Storage	**931**	580
Other	**747**	484
Construction work in progress	**376**	247
Total gross PP&E	**9,779**	6,266
Less accumulated depreciation	**1,879**	1,861
Total net PP&E	**$7,900**	$4,405

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

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

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 valued at cost. Central Valley has two types of pad gas in its reservoir storage facility. The first is non-depreciable PP&E, which is valued 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.

	2011	2010	2009
Atlanta Gas Light[1]	**2.6%**	2.5%	2.5%
Chattanooga Gas[1]	**2.5%**	2.8%	3.4%
Elizabethtown Gas[2]	**2.5%**	2.4%	3.1%
Elkton Gas[2]	**2.4%**	2.3%	2.1%
Florida City Gas[2]	**3.9%**	3.7%	3.9%
Nicor Gas[2]	**4.1%**	n/a	n/a
Virginia Natural Gas[1]	**2.5%**	3.0%	2.6%

[1] Average composite straight-line depreciation rates for depreciable property, excluding transportation equipment

[2] Composite straight-line depreciation rates

We compute depreciation expense on a straight-line basis over the following estimated useful lives of the assets.

In years	Estimated useful life
Transportation equipment[1]	5 – 10
Cargo shipping – vessels	20 – 25
Cargo shipping – freight equipment and freight handling equipment	8 – 18
Storage caverns	40
Other	up to 40

[1] May be depreciated in excess of useful life and recovered in rates.

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 capitalizes AFUDC at the current actual cost of debt. The capital expenditures of our two other utilities do not qualify for AFUDC treatment. More information on our authorized AFUDC rates is provided in the following table.

	2011	2010	2009
Atlanta Gas Light[1]	**8.10%**	8.10%	8.53%
Chattanooga Gas[2]	**7.41%**	7.41%	7.89%
Elizabethtown Gas[3]	**0.53%**	0.40%	0.41%
Virginia Natural Gas[4]	**7.38%**	—	9.24%
AFUDC (in millions)[5]	**$6**	$3	$13

[1] New rate as of November 1, 2010.

[2] New rate as of June 1, 2010.

[3] Variable rate is determined by FERC method of AFUDC accounting.

[4] Approved only for Hampton Roads construction project which ended in 2009. Virginia Natural Gas received no AFUDC interest for 2010 or 2011.

[5] Expense recorded in the Consolidated Statements of Income.

Within our midstream operations segment, we have recorded capitalized interest as part of the cost of the Golden Triangle Storage and Central Valley construction projects in our Consolidated Statements of Financial Position, and within interest expense in our Consolidated Statements of Income, in the amounts of $1 million in 2011, $5 million in 2010 and $3 million in 2009.

Goodwill and Intangible Assets

Goodwill is the excess of the purchase price over the fair value of identifiable net assets acquired in business combinations. The fair values assigned to the trade name and customer relationship intangible assets at Nicor's unregulated operations were determined using a combination of the cost savings, the multi-period excess earnings and the relief-from-royalty approaches.

In accordance with the authoritative guidance, we evaluate our goodwill balances for impairment on an annual basis or more frequently if impairment indicators arise. These indicators include, but are not limited to, a significant change in operating performance, the business climate, legal or regulatory factors, or a planned sale or disposition of a significant portion of the business. We test goodwill impairment utilizing a fair value approach at a reporting-unit level which generally equates to our operating segments as discussed in Note 13. An impairment charge is recognized if the carrying value of a reporting unit's goodwill exceeds its implied fair value. See Note 3 for a rollforward of total goodwill by operating segment.

Our goodwill impairment analysis for the years ended December 31, 2011 and 2010 was performed during the fourth quarter of each year and indicated that the fair value of each reporting unit is substantially in excess of carrying value, and the reporting units are not at risk of failing Step 1 of the impairment evaluation. As a result, we did not recognize any goodwill impairment charges.

In accordance with the authoritative guidance, we amortize intangible assets over their useful lives. These assets are reviewed

for impairment when indicators arise, at which time we assess the recoverability of such assets by determining whether the carrying value will be recovered through expected future cash flows. In the event the sum of the expected future cash flows resulting from the use of the asset is less than the carrying value of the asset, an impairment loss equal to the excess of the asset's carrying value over its fair value is recorded. No impairment has been recognized. We currently have no material indefinite lived intangible assets.

Taxes

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

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

Investment and Other Tax Credits Deferred investment tax credits associated with distribution operations are included as a regulatory liability in our Consolidated Statements of Financial Position. These investment tax credits are being amortized over the estimated life of the related properties as credits to income in accordance with regulatory requirements.

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.

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. In accordance with authoritative guidance related to rate-regulated entities, the amount of such a 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 or approximately 30 years.

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.

Tax Benefits The authoritative guidance related to income taxes requires us to determine whether tax benefits claimed or expected to be claimed on our tax return should be recorded in our consolidated financial statements. Under this guidance, we may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. This guidance also 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 the Consolidated Statements of Income. As of December 31, 2011, we did not have a liability recorded for payment of interest and penalties associated with uncertain tax positions.

Tax Collections We do not collect income taxes from our customers on behalf of governmental authorities. We collect and remit various taxes on behalf of various governmental authorities. We record these amounts in our Consolidated Statements of Financial Position. 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. These taxes were immaterial for all periods presented.

Revenues

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

As required by the Georgia Commission, in July 1998, Atlanta Gas Light began billing Marketers in equal monthly installments for each residential, commercial and industrial customer's distribution

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

All of our utilities, with the exception of Atlanta Gas Light, have rate structures which include volumetric rate designs that allow recovery of costs through gas usage. Revenues from sales and transportation services are recognized in the same period in which the related volumes are delivered to customers. Revenues from residential and certain commercial and industrial customers are recognized on the basis of scheduled meter readings. Additionally, revenues are recorded for estimated deliveries of gas not yet billed to these customers, from the last 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 WNA's that partially mitigate the impact of unusually cold or warm weather on customer billings and operating margin. The WNA's purpose is to reduce the effect of weather on customer bills by reducing bills when winter weather is colder than normal and increasing bills when weather is warmer than normal. In addition, the tariffs for Chattanooga Gas and Elkton Gas contain revenue normalization mechanisms that mitigate the impact of conservation and declining customer usage.

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 at Jefferson Island and Golden Triangle Storage in the period in which actual volumes are transported and storage services are provided. The majority of our storage services are covered under medium to long-term contracts at fixed market-based rates. We recognize our park and loan revenues ratably over the life of the contract.

Cargo shipping Revenues and related delivery costs 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

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. Therefore, 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 Statements of Consolidated 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.

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 for 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.

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 is due to the issuance of 38.2 million shares in connection with the Nicor merger on December 9, 2011. The effect of the additional shares was reduced as the shares were only outstanding for 22 days. We had 117.0 million shares outstanding as of December 31, 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 shares of the restricted stock and restricted stock units depends on the satisfaction of certain performance criteria. The future issuance of shares underlying the outstanding stock options depends on whether the exercise prices of the stock options are less than the average market price of the common shares for the respective periods. 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)	**2011**	2010	2009
Net income attributable to AGL Resources Inc.	**$ 172**	$ 234	$ 222
Denominator:			
Basic weighted-average number of shares outstanding[(1)]	**80.4**	77.4	76.8
Effect of dilutive securities	**0.5**	0.4	0.3
Diluted weighted-average number of shares outstanding	**80.9**	77.8	77.1
Basic and diluted earnings per share			
Basic	**$2.14**	$3.02	$2.89
Diluted	**$2.12**	$3.00	$2.88

(1) Daily weighted average shares outstanding.

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

		December 31,	
In millions	**2011**	2010	2009
Twelve months ended	—	0.8	2.0

The decrease in the number of shares that were excluded from the computation for the year ended December 31, 2011 and 2010 is the result of an increase in the average market value of our common shares for the years ended December 31, 2011 compared to 2010 and 2009.

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	December 31, 2011	2010
Regulatory assets – current		
Recoverable regulatory infrastructure program costs	**$ 48**	$ 48
Recoverable ERC	**7**	7
Recoverable seasonal rates	**10**	11
Recoverable retirement benefit costs	**29**	—
Other	**37**	26
Total regulatory assets – current	**131**	92
Regulatory assets – long-term		
Recoverable regulatory infrastructure program costs	**305**	244
Recoverable retirement benefit costs	**262**	9
Recoverable ERC	**351**	164
Unamortized losses on reacquired debt	**21**	11
Other	**140**	25
Total regulatory assets – long-term	**1,079**	453
Total regulatory assets	**$1,210**	$545
Regulatory liabilities – current		
Accumulated removal costs	**$ 14**	$ —
Accrued natural gas costs	**53**	23
Bad debt rider	**30**	—
Other	**15**	8
Total regulatory liabilities – current	**112**	31
Regulatory liabilities – long-term		
Accumulated removal costs	**1,321**	182
Regulatory income tax liability	**27**	15
Bad debt rider	**14**	—
Unamortized investment tax credit	**32**	12
Other	**11**	16
Total regulatory liabilities – long-term	**1,405**	225
Total regulatory liabilities	**$1,517**	$256

The increase of $665 million in regulatory assets includes $545 million related to the addition of Nicor Gas' regulatory assets and the increase of $1,261 million in regulatory liabilities includes $1,330 million related to the addition of Nicor Gas' regulatory liabilities.

Our regulatory assets are probable or recovery specifically authorized by a state regulatory commission. Base rates are designed to provide both a recovery of cost and a return on investment during the period rates are in effect. As such, all of our regulatory assets 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 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 also provide a return on investment during the period of recovery. However, there is no interest associated with the under or over collections of bad debt expense.

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 of 9 to 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 probabilistic models of potential costs, 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. However, we have not yet performed these probabilistic models for all of our sites in Illinois, which will be completed in 2012.

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 only allows for recovery of the costs incurred over the subsequent five-year period. 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 the benchmark bad debt expense included in its rates for the respective year. The benchmark, against which 2011 actual bad debt experience is compared, is approximately $63 million. Nicor Gas' actual 2011 bad debt expense was $31 million, resulting in a refund to customers of $32 million which will be refunded between June 2012 and May 2013. The prior year's bad debt rider is recorded within operating expenses on our Consolidated Statements of Income and the over, or under, recovery is recorded as a regulatory asset or liability on our Consolidated Statements of Financial Position.

Other Regulatory Assets and Liabilities Our recoverable 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. Recoverable seasonal rates reflect the difference between the recognition of a portion of Atlanta Gas Light's residential base rates revenues on a straight-line basis as compared to the collection of the revenues over a seasonal pattern. These amounts are fully recoverable through base rates within one year.

Accumulated Removal Costs In accordance with regulatory treatment, our depreciation rates are comprised of two cost components – historical cost, net of estimated salvage, and the estimated cost of removal, or retirement, 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 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 $1.1 billion from December 31, 2010, principally related to Nicor Gas.

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 2011, 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:

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

Atlanta Gas Light has recorded a current regulatory asset of $48 million, which represents the expected future collection of both expenditures already incurred and expected future capital expenditures to be incurred through the remainder of the program. Atlanta Gas Light has also recorded a non-current asset of $305 million, which represents the expected amount to be collected from customers over the next 12 months. The amounts recovered from the pipeline replacement revenue rider during the last three years were:

- $48 million in 2011
- $45 million in 2010
- $41 million in 2009

As of December 31, 2011, Atlanta Gas Light had recorded a current liability of $131 million representing expected program expenditures for the next 12 months and a noncurrent liability of $145 million, representing expected program expenditures through the end of the program in 2013.

Atlanta Gas Light capitalizes and depreciates the capital expenditure costs incurred from the pipeline replacement program over the life of the assets. Operation and maintenance costs are expensed as incurred. Recoveries, which are recorded as revenue, are based on a formula that allows Atlanta Gas Light to recover

operation and maintenance costs in excess of those included in its current base rates, depreciation expense and an allowed rate of return on capital expenditures. In the near term, the primary financial impact to Atlanta Gas Light from the pipeline replacement program is reduced cash flow from operating and investing activities, as the timing related to cost recovery does not match the timing of when costs are incurred. However, Atlanta Gas Light is allowed the recovery of carrying costs on the under-recovered balance resulting from the timing difference.

The Georgia Commission has also approved Atlanta Gas Light's STRIDE program, which is comprised of the ongoing pipeline replacement program, the new Integrated System Reinforcement Program (i-SRP) and the new Integrated Customer Growth Program (i-CGP). 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. We expect to file for an extension of the program in 2012.

Accounting for Retirement Benefit Plans

The authoritative guidance related to retirement benefits requires that we recognize all obligations related to defined benefit retirement plans 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 were 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 authoritative guidance has no effect on our calculation of basic or diluted earnings per common share amounts, which are based upon net income attributable to AGL Resources Inc. For additional information, see Note 10.

We also invest in partnerships and limited liability companies that are accounted for under the equity method, but are not joint ventures. In accordance with the authoritative guidance, 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 in equity investment 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. We based our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances, and we evaluate our estimates on an ongoing basis. Our estimates may involve complex situations requiring a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our financial statements. The most significant estimates relate to our pipeline replacement program accruals, environmental liability accruals, uncollectible accounts and other allowance for contingent losses, goodwill and intangible assets, retirement plan obligations, derivative and hedging activities and provisions for income taxes. Our actual results could differ from our estimates.

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 preliminary 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, and was performed by a third-party independent valuation specialist. The preliminary allocation of the purchase price is presented in the following table.

In millions	
Current assets	$ 932
Property, plant and equipment	3,202
Goodwill	1,395
Other noncurrent assets, excluding goodwill	791
Current liabilities	(1,170)
Long-term debt	(599)
Other noncurrent liabilities	(2,048)
Total purchase consideration	$ 2,503

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. Modifications to the purchase price allocation may occur as a result of continuing review of the assumptions and estimates underlying the preliminary fair value adjustments of environmental site remediation and other adjustments.

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 preliminary rollforward of total goodwill recognized by segment in our Consolidated Statements of Financial Position is as follows:

In millions	Distribution Operations	Retail Operations	Wholesale Services	Midstream Operations	Cargo Shipping	Other	Consolidated
As of December 31, 2010	$ 404	$ —	$—	$14	$ —	$—	$ 418
Merger with Nicor	1,182	124	2	2	77	8	1,395
As of December 31, 2011	$1,586	$ 124	$ 2	$16	$77	$ 8	$1,813

The preliminary valuation of the additional intangible assets recorded as result of the merger is as follows:

In millions	Preliminary valuation	Weighted-average amortization period
Trade names:		
Retail Operations	$ 33	15 years
Cargo Shipping	15	15 years
Customer relationships:		
Retail Operations	52	10 years
Cargo Shipping	3	18 years
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 approximately $68 million ($55 million net of tax) for the twelve months ended December 31, 2011, compared to $6 million ($4 million net of tax) for the same period in 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.

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

In millions, except per share amounts	December 10, 2011-December 31, 2011
Total revenues	$ 209
Net income[1]	$ (24)
Basic earnings per common share	$(0.30)
Diluted earnings per common share	$(0.30)

[1] 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 approximately $86 million of costs directly related to the merger in the twelve months ended December 31, 2011 and $10 million for the same period 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 the future consolidated results of operations of the combined company.

In millions, except per share amounts	12 months ended December 31, **2011**	2010
Total revenues	**$4,715**	$5,083
Net income attributable to AGL Resources Inc.	**$ 313**	$ 343
Basic earnings per common share	**$ 2.69**	$ 2.97
Diluted earnings per common share	**$ 2.68**	$ 2.96

Notes to Consolidated Financial Statements

Note 4 Fair Value Measurements

Derivative Instruments

The following table summarizes, by level within the fair value hierarchy, our derivative assets and liabilities that were accounted for at fair value on a recurring basis for the years ended December 31, 2011 and 2010.

	December 31, 2011		December 31, 2010	
In millions	Assets[1]	Liabilities	Assets[1]	Liabilities
Natural gas derivatives				
Quoted prices in active markets (Level 1)	**$ 38**	**$(145)**	$ 22	$(71)
Significant other observable inputs (Level 2)	**229**	**(68)**	153	(29)
Netting of cash collateral	**32**	**115**	53	52
Total carrying value[2][3]	**$299**	**$ (98)**	$228	$(48)
Interest rate derivatives				
Significant other observable inputs (Level 2)	**$ 13**	**$ (13)**	$ —	$ —

[1] $3 million of premium at December 31, 2011 and less than $1 million at December 31, 2010 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, 2011, we held $59 million in money market funds which are recorded at fair value and classified as Level 1 within the fair value hierarchy.

Retirement benefit plans

The target asset allocation of the Nicor Companies Pension and Retirement Plan (Nicor Gas Retirement Plan) is approximately 60% equity and 40% fixed income. The AGL Resources Inc. Retirement Plan (AGL Retirement Plan), the Employees' Retirement Plan of NUI Corporation (NUI Retirement Plan), the Health and Welfare Plan for Retirees and Inactive Employees of AGL Resources Inc. (AGL Postretirement Plan) target asset allocations are approximately 80% equity and 20%fixed income. The plans investments policy provides 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, 2011									
	Pension plans[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	$ —	$—	$ 13	2%	$1	$—	$—	$ 1	2%
Equity Securities										
U.S. large cap[2]	95	134	—	229	30%	—	34	—	34	56%
U.S. small cap[2]	53	25	—	78	10%	—	—	—	—	—%
International companies[2]	—	107	—	107	14%	—	10	—	10	16%
Emerging markets[4]	—	25	—	25	3%	—	—	—	—	—%
Fixed income securities										
Corporate bonds[5]	—	191	—	191	25%	—	—	—	—	—%
Other types of investments										
Other (or gov't/muni bonds)	—	28	—	28	4%	—	16	—	16	26%
Global hedged equity[6]	—	—	30	30	4%	—	—	—	—	—%
Absolute return[7]	—	—	34	34	5%	—	—	—	—	—%
Private capital[8]	—	—	25	25	3%	—	—	—	—	—%
Total assets at fair value	$161	$510	$89	$760	100%	$1	$60	$—	$61	100%
% of fair value hierarchy	21%	67%	12%	100%		2%	98%	—%	100%	

In millions	December 31, 2010									
	Pension plans[1]					Other retirement plans				
	Level 1	Level 2	Level 3	Total	% of total	Level 1	Level 2	Level 3	Total	% of total
Cash	$ 7	$ —	$ —	$ 7	2%	$1	$ —	$—	$ 1	1%
Equity Securities										
U.S. large cap[2]	91	—	—	91	26%	—	36	—	36	57%
U.S. small cap[2]	51	—	—	51	15%	—	—	—	—	—%
International companies[3]	—	43	—	43	12%	—	12	—	12	19%
Emerging markets[4]	—	16	—	16	4%	—	—	—	—	—%
Fixed income securities										
Corporate bonds[5]	—	56	—	56	16%	—	15	—	15	23%
Other types of investments										
Global hedged equity[6]	—	—	35	35	10%	—	—	—	—	—%
Absolute return[7]	—	—	30	30	9%	—	—	—	—	—%
Private capital[8]	—	—	22	22	6%	—	—	—	—	—%
Total assets at fair value	$149	$115	$87	$351	100%	$1	$63	$—	$64	100%
% of fair value hierarchy	42%	33%	25%	100%		1%	99%	—%	100%	

[1] Includes $6 million at December 31, 2011 and $7 million at December 31, 2010 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

In millions	Fair value measurements using significant unobservable inputs – Level 3 December 31, 2011[2]				
	Global hedged equity	Absolute return	Private capital	Equity securities – international companies	Total
Assets:					
Beginning balance	$35	$ 30	$22	$—	$ 87
Gains included in changes in net assets	(1)	1	5	—	5
Purchases	2	3	1	—	6
Sales	(6)	—	(3)	—	(9)
Ending balance	$30	$ 34	$25	$—	$ 89

In millions	December 31, 2010[2]				
	Global hedged equity	Absolute return	Private capital	Equity securities – international companies	Total
Assets:					
Beginning balance	$33	$ 26	$13	$ 5	$ 77
Transfers out of Level 3[1]	—	—	—	(4)	(4)
Gains included in changes in net assets	2	2	2	—	6
Purchases	—	14	8	—	22
Sales	—	(12)	(1)	(1)	(14)
Ending balance	$35	$ 30	$22	$—	$ 87

[1] Transferred to Level 2 as a result of change in investment vehicle and pricing inputs becoming directly observable. Transfers out of Level 3 are determined using values at the end of the period in which the transfer occurs.

[2] There were no transfers between Level 1 and Level 2 for any of the periods presented.

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	**2011**	2010
Long-term debt amortized cost [1]	**$3,576**	$1,971
Long-term debt fair value [1]	**$3,938**	$2,122

[1] December 31, 2011 includes the debt assumed in the Nicor merger with a carrying value of $500 million, as well as $15 million of medium-term notes that are due in June 2012. December 31, 2010 includes $300 million of senior notes repaid in January 2011.

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 contracts
- futures contracts
- options contracts
- financial swaps
- treasury locks
- weather derivative contracts
- storage and transportation capacity transactions
- 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, 2011 for agreements with such features, derivative instruments with liability fair values totaled approximately $110 million 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 $(24) million in 2011, $(2) million in 2010 and $11 million in 2009.

On May 4, 2011, we entered into interest rate swaps with an aggregate notional amount of $250 million to effectively convert a portion of our fixed-rate interest obligation on the $300 million 6.40% senior notes due July 15, 2016 to a variable-rate obligation. We pay a floating interest rate equal to the three-month LIBOR plus 3.9%. We designated these interest rate swaps as fair value hedges. We also held forward-starting interest rate swaps with a notional amount totaling $90 million at December 31, 2011, that were redesignated as cash flow hedges upon the close of the merger. Under the terms of the swaps, we agree to pay a fixed swap rate and receive a floating rate based on a variable three-month LIBOR rate. We designated these interest rate swaps as cash flow hedges. The fair values of our interest rate swaps were reflected as 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 table below summarizes the various ways in which we account for our derivative instruments and the impact on our Consolidated Financial Statements:

	Recognition and Measurement	
Accounting Treatment	**Statement of Financial Position**	**Income Statement**
Cash flow hedge	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 other comprehensive income (loss)	Effective portion of the gain or loss on the derivative instrument is reclassified out of accumulated OCI (loss) and into earnings when the forecasted 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
	Nicor Gas' and Elizabethtown Gas' unrealized gains and losses on derivative instruments are deferred as regulatory assets or liabilities until included in natural gas costs	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, 2011 and 2010, 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, 2011 and 2010, we had net long natural gas contracts outstanding in the following quantities:

Natural gas contracts

	Distribution Operations		All Other	
In Bcf	**December 31, 2011 [1] [2]**	December 31, 2010	**December 31, 2011 [1]**	December 31, 2010
Hedge designation:				
Cash flow	**–**	–	**5**	4
Not designated	**48**	18	**138**	202
Total	**48**	18	**143**	206
Hedge position:				
Short	**–**	–	**(1,680)**	(1,605)
Long	**48**	18	**1,823**	1,811
Net long position	**48**	18	**143**	206

[1] Approximately 97% of these contracts have durations of two years or less and the remaining 3% 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	2011	2010
Nicor Gas	**$ 3**	n/a
Elizabethtown Gas	**$27**	$35

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

In millions	Statement of financial position location [1][2]	December 31, 2011	2010
Designated as cash flow and fair value hedges			
Asset Instruments			
Current natural gas contracts	Derivative instruments assets and liabilities – current portion	**$ 9**	$ 3
Noncurrent natural gas contracts	Derivative instruments assets and liabilities	**–**	–
Interest rate swap agreements	Derivative instruments assets – long-term portion	**13**	–
Liability Instruments			
Current natural gas contracts	Derivative instruments assets and liabilities – current portion	**(12)**	(5)
Interest rate swap agreements	Derivative instruments liabilities – long-term portion	**(13)**	–
Total		**(3)**	(2)
Not designated as cash flow hedges			
Asset Instruments			
Current natural gas contracts	Derivative instruments assets and liabilities – current portion	**728**	541
Noncurrent natural gas contracts	Derivative instruments assets and liabilities	**137**	105
Liability Instruments			
Current natural gas contracts	Derivative instruments assets and liabilities – current portion	**(689)**	(489)
Noncurrent natural gas contracts	Derivative instruments assets and liabilities	**(116)**	(80)
Total		**60**	77
Total derivative instruments		**$ 57**	$ 75

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

[2] As required by the authoritative guidance related to derivatives and hedging, the fair value amounts above are presented on a gross basis. As a result, the amounts above do not include cash collateral held on deposit in broker margin accounts of $147 million as of December 31, 2011 and $105 million as of December 31, 2010. 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 twelve months ended December 31, 2011 and 2010.

In millions	2011	December 31, 2010	2009
Designated as cash flow hedges			
Natural gas contracts – loss recognized in OCI			
Natural gas contracts – loss reclassified from OCI into cost of goods sold for settlement of hedged item	**$ (6)**	$(16)	$(31)
Interest rate swaps – ineffectiveness recorded as an offset to interest expense	**3**	—	—
Not designated as hedges			
Natural gas contracts – fair value adjustments recorded in operating revenues[1]	**40**	(1)	21
Natural gas contracts – net gain fair value adjustments recorded in cost of goods sold[2]	**—**	(2)	1
Natural gas contracts – net loss fair value adjustments recorded in operation and maintenance expense	**(4)**	—	—
Total gains (losses) on derivative instruments	**$33**	$(19)	$ (9)

[1] Associated with the fair value of existing derivative instruments at December 31, 2011, 2010 and 2009.

[2] Excludes losses recorded in cost of goods sold associated with weather derivatives of $9 million for the year ended December 31, 2011, $27 million for the year ended December 31, 2010 and $6 million for the year ended December 31, 2009.

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, 2011, 2010 and 2009.

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 $2 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, 2011.

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 Retirement Plan, and on the actual fair market value of plan assets, which is used by the Nicor Gas Retirement Plan (our two largest pension plans), to determine the expected return on the plan assets component of net annual pension cost. The MRVPA is a calculated value and differs from the actual market value of plan assets. Gains and losses on plan assets are spread through the MRVPA based on the five-year moving weighted average methodology.

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.

Pension Benefits

We sponsor three tax-qualified defined benefit retirement plans for our eligible employees, the Nicor Gas Retirement Plan, the AGL Retirement Plan and the NUI Retirement Plan. A defined benefit plan specifies the amount of benefits an eligible participant eventually will receive using information about the participant.

The Nicor Gas Retirement Plan is a noncontributory defined benefit pension plan covering substantially all employees of Nicor Gas 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.

We generally calculate the benefits under the AGL Retirement Plan based on age, years of service and pay. The benefit formula for the AGL Retirement Plan is a career average earnings formula, except for participants who were employees as of July 1, 2000, and who were at least 50 years of age as of that date. For those participants, we used a final average earnings benefit formula, and used this benefit formula for such participants until December 31, 2010, at which time any of those participants who were still actively employed accrue future benefits under the career average earnings formula.

Effective January 1, 2012, the AGL Retirement 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 plan.

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

Other Defined Benefit Retirement Benefits

We sponsor two defined benefit retirement 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. Eligibility for these benefits is based on age and years of service.

The AGL Welfare Plan includes medical coverage for all eligible AGL Resources employees who were employed as of June 30, 2002, if they reach retirement age while working for us. In addition, the AGL 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.

Nicor Gas provides health care and life insurance benefits to eligible retired employees under the Nicor Gas Welfare Benefit Plan that includes a limit on its share of cost for employees hired after 1982.

We recorded a regulatory asset for anticipated future recoveries of $291 million as of December 31, 2011 and $9 million as of December 31, 2010. In addition, we recorded a regulatory liability of $19 million as of December 31, 2011 and $6 million as of December 31, 2010 for our expected expenses under the AGL Welfare Plan and the Nicor Gas Welfare Benefit Plan. We expect to pay $21 million of insurance claims for these plans in 2012, but we do not anticipate making any additional contributions.

Effective December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 was signed into law. This act provides for a prescription drug benefit under Medicare Part D as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. We determined that the Nicor Gas prescription drug benefits of its plan are actuarially equivalent and accordingly have reflected the effects of the subsidy in the determination of the benefit obligation and annual net benefit.

Effective July 1, 2009, 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.

Effective January 1, 2010, enhancements were made to the pre-65 medical coverage of the AGL Welfare Plan by removing the current cap on our expected costs and implementing a new cap determined by the new retiree premium schedule based on salary level and years of service. 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.

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 2011. The PBO associated with this plan was $3 million December 31, 2011.

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. If certain conditions were met, the Worker, Retiree and Employer Recovery Act of 2008 allowed us to measure our required minimum contributions based on a funding target of 100% in 2010 and 2011. In 2011 we contributed $56 million to the AGL Retirement Plan and the NUI Retirement Plan. In 2010 we contributed $31 million to the AGL Retirement Plan and the NUI Retirement Plan. No contributions were made to the Nicor Gas Retirement Plan in 2011. For more information on our 2012 contributions to our pension plans, see Note 11.

Assumptions

We consider a number of factors in determining and selecting assumptions for the overall expected long-term rate of return on plan assets. We consider the historical long-term return experience of our assets, the current and expected allocation of our plan assets, and expected long-term rates of return. We derive these expected long-term rates of return with the assistance of our investment advisors and generally base these rates on the various asset classes, our expected investments of plan assets and asset management. We base our expected allocation of plan assets on a diversified portfolio consisting of domestic and international equity securities, fixed income securities, real estate, private equity securities and alternative asset classes.

We consider a variety of factors in determining and selecting our assumptions for the discount rate at December 31. We based our discount rate on a yield curve provided by our actuaries that is derived from a portfolio of high quality (rated AA or better) corporate bonds and the equivalent annuity cash flows separately for each pension plan.

Notes to Consolidated Financial Statements

The following tables present details about our pension and other retirement plans.

Dollars in millions	Pension plans 2011	Pension plans 2010	Other retirement plans 2011	Other retirement plans 2010
Change in plan assets				
Fair value of plan assets, January 1,	**$ 344**	$ 303	**$ 71**	$ 63
Plan assets acquired in Nicor merger	**388**	—	**—**	—
Actual return on plan assets	**(7)**	37	**(3)**	8
Employer contributions	**58**	31	**8**	7
Benefits paid	**(28)**	(27)	**(9)**	(7)
Plan curtailment and settlements	**(1)**	—	**—**	—
Fair value of plan assets, December 31,	**$ 754**	$ 344	**$ 67**	$ 71
Change in benefit obligation				
Benefit obligation, January 1,	**$ 531**	$ 463	**$ 107**	$101
Benefit obligations acquired in Nicor merger	**345**	—	**273**	—
Service cost	**14**	11	**1**	—
Interest cost	**29**	27	**6**	6
Actuarial loss	**78**	57	**18**	7
Medicare Part D reimbursements	**—**	—	**1**	—
Benefits paid	**(28)**	(27)	**(9)**	(7)
Plan curtailment and settlements	**(1)**	—	**—**	—
Benefit obligation, December 31,	**$ 968**	$ 531	**$ 397**	$107
Funded status at end of year	**$(214)**	$(187)	**$(330)**	$ (36)
Amounts recognized in the Consolidated Statements of Financial Position consist of				
Long-term asset	**$ 26**	$ —	**$ —**	$ —
Current liability	**(2)**	(1)	**(14)**	—
Long-term liability	**(238)**	(186)	**(316)**	(36)
Total liability at December 31,	**$(214)**	$(187)	**$(330)**	$ (36)
Accumulated benefit obligation[2]	**$ 910**	$ 506	**n/a**	n/a
Supplemental information for underfunded pension plans included above as of December 31, 2011:				
Aggregate benefit obligation	**$ 604**	$ 531	**n/a**	n/a
Aggregate accumulated benefit obligation	**570**	506	**n/a**	n/a
Aggregate fair value of plan assets	**$ 363**	$ 344	**n/a**	n/a
Assumptions used to determine benefit obligations				
Discount rate	**4.6%**	5.4%	**4.5%**	5.2%
Rate of compensation increase	**3.7%**	3.7%	**3.7%**	3.7%
Pension band increase[1]	**2.0%**	n/a	**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.

Dollars in millions	Pension plans 2011	2010	2009	Other retirement plans 2011	2010	2009
Net benefit cost						
Service cost	**$ 14**	$ 11	$ 8	**$ 1**	$—	$—
Interest cost	**29**	27	26	**6**	6	6
Expected return on plan assets	**(33)**	(28)	(29)	**(5)**	(5)	(4)
Net amortization of prior service cost	**(2)**	(2)	(2)	**(4)**	(4)	(4)
Recognized actuarial loss	**14**	10	9	**2**	2	2
Net periodic benefit cost	**$ 22**	$ 18	$ 12	**$—**	$ (1)	$—
Assumptions used to determine benefit costs						
Discount rate[1]	**5.4%**	6.0%	6.2%	**5.2%**	5.8%	6.2%
Expected return on plan assets[1]	**8.5%**	8.8%	9.0%	**8.2%**	8.8%	9.0%
Rate of compensation increase[1]	**3.7%**	3.7%	3.7%	**3.7%**	3.7%	3.7%
Pension band increase[1][2]	**2.0%**	n/a	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 2011 health care benefit cost for the Nicor Gas Welfare Benefit Plan were as follows:

	2011
Health care cost trend rate assumed for next year	8.60%
Ultimate rate to which the cost trend rate is assumed to decline	4.50%
Year that reaches ultimate trend rate	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	$—	$ 26
1% Health care cost trend rate decrease	—	(22)

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.

Notes to Consolidated Financial Statements

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, 2011 and 2010:

	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, 2011:						
Prior service cost (credit)	**$ 1**	**$ 1**	**$ (13)**	**$ (4)**	**$ (12)**	**$ (3)**
Net loss	**162**	**118**	**312**	**51**	**474**	**170**
Total	**$163**	**$119**	**$299**	**$47**	**$462**	**$167**
December 31, 2010:						
Prior service credit	$ —	$ —	$ (15)	$ (8)	$ (15)	$ (8)
Net loss	—	—	226	35	226	35
Total	$ —	$ —	$211	$27	$211	$ 27

The 2012 estimated amortization out of regulatory assets or accumulated OCI for these plans are set forth in the following table.

	Net Regulatory Assets		Accumulated OCI		Total	
In millions	Pension plan	Other retirement plans	Pension plan	Other retirement plans	Pension plan	Other retirement plans
Amortization of prior service credit	$ —	$ —	$ (2)	$ (3)	$ (2)	$ (3)
Amortization of net loss	14	8	20	3	33	11

The following table presents the gross benefit payments expected for the years ended December 31, 2012 through 2021 for our pension and other retirement plans. There will be benefit payments under these plans beyond 2021.

In millions	Pension plans	Other retirement plans	Expected Medicare subsidy
2012	$ 56	$ 23	$ 2
2013	55	23	2
2014	59	24	2
2015	62	25	2
2016	64	26	2
2017-2021	367	144	12

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 $7 million in 2011, $7 million in 2010 and $7 million in 2009.

Note 7 Stock-Based Compensation

General

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

	Shares issuable upon exercise of outstanding stock options, warrants & rights[1]	Shares available for future issuance	Details
Omnibus Performance Incentive Plan, as amended and restated[2]	866,249	4,787,707	Shares available for future issuance may be issued in the form of grants of incentive and nonqualified stock options, stock appreciation rights (SARs), shares of restricted stock, restricted stock units and performance cash awards to key employees.
Long-Term Incentive Plan (1999)	1,362,032	—	Plan previously provided for grants of incentive and nonqualified stock options, shares of restricted stock and performance units to key employees. No further grants will be made except for reload options that may be granted under the plan's outstanding options.
Officer Incentive Plan	5,000	—	Plan previously provided for grants of nonqualified stock options and shares of restricted stock to new-hire officers. No future grants will be made under this plan.
2006 Non-Employee Directors Equity Compensation Plan	not applicable	119,954	Grants of stock to non-employee directors in connection with non-employee director compensation (for annual retainer, chair retainer and for initial election or appointment).
1996 Non-Employee Directors Equity Compensation Plan	7,173	—	Plan previously provided for grants of nonqualified stock options and stock to non-employee directors in connection with non-employee director compensation (for annual retainer and for initial election or appointment). The plan was amended in 2002 to eliminate the granting of stock options. No future grants will be made under this plan.
Employee Stock Purchase Plan	not applicable	332,205	Nonqualified, broad-based employee stock purchase plan for eligible employees.

[1] As of December 31, 2011.

[2] Includes 1,664,133 shares, previously available under the Nicor Inc. 2006 Long-Term Incentive Plan, as amended, that were assumed and now available under the Omnibus Performance Plan, pursuant to NYSE rules.

Accounting Treatment and Compensation Expense

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

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

Performance-based stock awards and performance units contain market conditions. Stock options, restricted stock awards and performance units also contain a service condition.

We estimate forfeitures over the required service period when recognizing compensation expense. These estimates are adjusted to the extent that actual forfeitures differ, or are expected to materially differ, from such estimates. The authoritative guidance requires excess tax benefits to be reported as a financing cash inflow. The difference between the proceeds from the exercise of our stock-based awards and the par value of the stock is recorded within premium on common stock.

We grant incentive and nonqualified stock options with a strike price equal to the fair market value on the date of the grant. Fair market value is defined under the terms of the applicable plans as the most recent closing price per share of AGL Resources common stock as reported in *The Wall Street Journal*. Stock options generally have a three-year vesting period. The following table provides additional information on compensation costs and income tax benefits and excess tax benefits related to our cash and stock-based compensation awards.

In millions	2011	2010	2009
Compensation costs[1]	**$14**	$11	$11
Income tax benefits[1]	**1**	2	2
Excess tax benefits[2]	**1**	2	2

[1] Recorded in our Consolidated Statements of Income.
[2] Recorded in our Consolidated Statements of Cash Flows.

Incentive and Nonqualified Stock Options

Nonqualified options generally expire 10 years after the date of grant. Participants realize value from option grants only to the extent that the fair market value of our common stock on the date of exercise of the option exceeds the fair market value of the common stock on the date of the grant.

As of December 31, 2011, we had an immaterial amount of unrecognized compensation costs related to stock options. Cash received from stock option exercises for 2011 was $11 million, and the income tax benefit from stock option exercises was $1 million. Intrinsic value for options is defined as the difference between the current market value and the grant price. The following tables summarize activity related to stock options for key employees and non-employee directors.

Stock Options	Number of options	Weighted average exercise price	Weighted average remaining life (in years)	Aggregate intrinsic value (in millions)
Outstanding – December 31, 2008	2,475,989	$34.52		
Granted	250,440	31.09		
Exercised	(119,126)	27.20		
Forfeited	(55,735)	36.50		
Outstanding – December 31, 2009	2,551,568	$34.48		
Granted	—	—		
Exercised	(296,008)	31.33		
Forfeited	(26,448)	37.85		
Outstanding – December 31, 2010	2,229,112	$34.85	5.2	
Granted	**1,685**	**42.19**	**1.6**	
Exercised	**(383,646)**	**31.11**	**3.0**	
Forfeited	**(23,997)**	**37.70**	**5.4**	
Outstanding – December 31, 2011	**1,823,154**	**$35.61**	**4.6**	**$ 12**
Exercisable – December 31, 2011	**1,747,656**	**$35.81**	**4.5**	**$ 11**
Exercisable – December 31, 2010	**1,799,334**	**$34.92**	**4.9**	**$ 4**
Exercisable – December 31, 2009	**1,767,248**	**$33.94**	**5.3**	**$ 6**

Unvested Stock Options	Number of unvested options	Weighted average exercise price	Weighted average remaining vesting period (in years)	Weighted average fair value
Outstanding – December 31, 2010	429,778	$34.58	0.5	$3.11
Granted	**1,685**	**42.19**	**—**	**3.00**
Forfeited	**(3,190)**	**31.09**	**0.6**	**1.24**
Vested	**(352,775)**	**35.40**	**—**	**$3.51**
Outstanding – December 31, 2011	**75,498**	**$31.09**	**0.1**	**$1.24**

Information about outstanding and exercisable options as of December 31, 2011, is as follows.

	Options outstanding			Options Exercisable	
Range of Exercise Prices	Number of options	Weighted average remaining contractual life (in years)	Weighted average exercise price	Number of options	Weighted average exercise price
$17.55 to $21.92	6,410	0.1	$21.28	6,410	$21.28
$21.93 to $26.30	10,763	1.0	23.82	10,763	23.82
$26.31 to $30.69	84,375	1.6	26.93	84,375	26.93
$30.70 to $35.08	443,664	5.0	32.23	368,166	32.46
$35.09 to $39.46	1,234,766	4.7	37.41	1,234,766	37.41
$39.47 to $43.85	43,176	5.0	41.09	43,176	41.09
Outstanding - Dec. 31, 2011	1,823,154	4.6	$35.61	1,747,656	$35.81

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. The following table shows the ranges for per share value and information about the underlying assumptions used in developing the grant date value for each of the grants made during 2011 and 2009. There were no options granted in 2010.

	2011	2009
Expected life (years)	**7**	7
United States Constant Maturity Treasury Rate used for risk-free interest rate %	**2.51%**	2.30%
Weighted average expected volatility %	**14.81%**	12.9%
Weighted average dividend yield %	**4.3%**	5.5%
Fair value of options granted - per share	**$3.00**	$1.24

With the implementation of our share repurchase program in 2006, we use shares purchased under this program to satisfy share-based exercises to the extent that repurchased shares are available. Otherwise, we issue new shares from our authorized common stock.

Performance Units

The compensation cost of restricted stock unit awards is equal to the grant date fair value of the awards, recognized over the required service period, determined according to the authoritative guidance related to stock compensation. The dollar value of performance cash unit awards is equal to the grant date fair value of the awards measured against progress towards the performance measure, recognized over the required service period, determined according to the authoritative guidance related to stock compensation. No other assumptions are used to value these awards. 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.

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 2011, we granted to a select group a total of 134,510 restricted stock units, of which 126,920 of these units were outstanding as of December 31, 2011. These restricted stock units had a performance measurement period that ended December 31, 2011, which was achieved, and a performance measure related to a basic earnings per common share attributable to AGL Resources Inc. common shareholders goal that was met.

Performance Cash Awards In general, a performance cash award represents the opportunity to receive cash, subject to the achievement of certain pre-established performance criteria. In 2011, we did not grant any performance cash awards. These awards have a performance measure that is related to annual growth in basic earnings per common share attributable to AGL Resources Inc. common shareholders and the average dividend yield. Accruals in connection with these grants are as follows:

In millions	Measurement period end date	Accrued at Dec. 31, 2011	Maximum aggregate payout
Year of grant			
2009[1]	Dec. 31, 2011	$1	$4

[1] Adjusted to reflect the effect of economic value created during the performance measurement period by our wholesale services segment.

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. In 2011 we granted performance share unit awards to a select group of officers. These awards have a performance measure that relates to the company's relative total shareholder return relative to a group of peer companies. Accruals in connection with these grants are as follows:

In millions	Measurement period end date	Accrued at Dec. 31, 2011	Maximum aggregate payout
Granted in 2010	Dec. 31, 2012	$4	$12
Granted in 2011	Dec. 31, 2013	$2	$13

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 required service period and is determined in accordance with the authoritative guidance related to stock compensation. 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. The following table summarizes activity during 2011, related to stock awards for our non-employee directors.

	Shares of restricted stock	Weighted average fair value
Issued	20,858	$40.62
Forfeited	—	—
Vested	20,858	$40.62
Outstanding	—	—

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

	Shares of restricted stock	Weighted average remaining vesting period (in years)	Weighted average fair value
Outstanding – December 31, 2009[1]	341,245		$33.93
Issued	205,030		36.34
Forfeited	(16,153)		34.13
Vested	(129,222)		35.19
Outstanding – December 31, 2010[1]	400,900	2.4	$30.80
Issued	**311,600**	**3.0**	**39.48**
Forfeited	**(25,784)**	**1.8**	**36.22**
Vested	**(209,362)**	**0**	**34.68**
Outstanding – December 31, 2011[1][2]	**477,354**	**2.6**	**$34.40**

[1] Subject to restriction.

[2] Includes 82,222 restricted shares with nonforfeitable dividend rights.

Employee Stock Purchase Plan (ESPP)

Under the ESPP, employees may purchase shares of our common stock in quarterly intervals at 85% of fair market value, we record an expense for the 15% purchase price discount. Employee ESPP contributions may not exceed $25,000 per employee during any calendar year.

	2011	2010	2009
Shares purchased on the open market	**65,843**	60,017	63,847
Average per-share purchase price	**$ 40.55**	$ 37.07	$ 31.45
Purchase price discount	**$401,346**	$333,639	$298,968

Note 8 Debt

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, 2011		December 31, 2010	
Dollars in millions	Year(s) due	Weighted- average interest rate	Outstanding	Weighted- average interest rate	Outstanding
Short-term debt					
Commercial paper- AGL Capital	2012	**0.4%**	**$ 869**	0.4%	$ 732
Commercial paper- Nicor Gas	2012	**0.4**	**452**	n/a	n/a
Current portion of long-term debt	2012	**8.3**	**15**	7.1	300
Current portion of capital leases	2012	**4.9**	**2**	4.9	1
Total short-term debt and current portion of long-term debt and capital leases		**0.7%**	**$1,338**	3.2%	$1,033
Long-term debt – net of current portion					
Senior notes	2013-2041	**5.4%**	**$2,550**	5.5%	$1,275
First mortgage bonds	2016-2038	**5.6**	**500**	n/a	n/a
Gas facility revenue bonds	2022-2033	**1.2**	**200**	1.3	200
Medium-term notes	2017-2027	**7.8**	**181**	7.8	196
First mortgage bonds fair value adjustment	2016-2038	**n/a**	**99**	n/a	n/a
Interest rate swaps fair value adjustment	2016	**n/a**	**13**	n/a	—
Capital leases	2012	**n/a**	**—**	4.9	2
Unamortized debt premium (discount), net	—	**n/a**	**18**	n/a	(2)
Total long-term debt		**5.0%**	**$3,561**	5.2%	$1,671
Total debt		**4.4%**	**$4,899**	4.6%	$2,704

Short-term Debt

Our short-term debt at December 31, 2011 and 2010 was composed of borrowings under our commercial paper programs and current portions of our long-term debt and capital lease obligations.

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 our other subsidiaries, including SouthStar, participate in the AGL Capital commercial paper program. At December 31, 2011, our commercial paper maturities ranged from 3 to 58 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, 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 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, 2011, there were no outstanding borrowings under this facility.

SouthStar Credit Facility SouthStar's five-year $75 million unsecured credit facility expired on November 2, 2011. SouthStar used this line of credit for working capital and general corporate

needs. SouthStar had no outstanding borrowings on this line of credit at December 31, 2010.

Current Portion of Long-Term Debt We have $15 million of medium-term notes, which are reported as current portion of long-term debt on our December 31, 2011 Consolidated Statements of Financial Position. Additionally, we had $300 million of senior notes, which are reported as current portion of long-term debt on our December 31, 2010 Consolidated Statements of Financial Position.

Current Portion of Capital Leases 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 will be repaid through 2012. Based on the terms of the lease agreement, Florida City Gas is required to insure the leased equipment during the lease term. At the expiration of the lease term, Florida City Gas has the option to purchase the leased meters from the lessor at their fair market value, which will be determined based on an arm's-length transaction between an informed and willing buyer.

Long-term Debt

Our long-term debt at December 31, 2011 and 2010 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, gas facility revenue bonds and capital leases. 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 2016. The annual maturities of our long-term debt for the next five years and thereafter are as follows:

Year	Amount (in millions)
2012	$ 17
2013	225
2014	—
2015	200
2016	545
Thereafter	2,461
Total	$3,448

Senior Notes 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 May 4, 2011, we entered into interest rate swaps with an aggregate notional amount of $250 million to effectively convert a portion of our $300 million 6.4% fixed-rate senior notes that mature July 15, 2016 to a variable-rate obligation. Under the terms of the swaps, the interest rates reset quarterly based on LIBOR plus 3.9%.

As of December 31, 2011, we also held forward-starting interest rate swaps totaling $90 million that were redesignated as cash flow hedges upon the close of the Nicor merger. Under the terms of the swaps, we agree to pay a fixed swap rate and receive a floating rate based on LIBOR.

First Mortgage Bonds As a result of the merger, we acquired the first mortgage bonds of Nicor Gas, which at December 31, 2011, had principal balances totaling $500 million. The fair value step-up of these bonds on December 9, 2011, the merger closing date, was $99 million, a step up to fair value that is reflected in our long-term debt. 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. In June and September 2010, the letters of credit supporting the gas revenue bonds were set to expire, and according to the terms of the bond indentures, we repurchased the bonds before the expiration of the letters of credit using the proceeds of AGL Capital commercial paper issuances.

Financial and Non-Financial Covenants

The AGL Credit Facility and the Nicor Gas Credit Facility include a financial covenant that requires us to maintain a ratio of total debt to total capitalization of no more than 70%; however, our goal is to maintain this ratio at levels between 50% and 60%. These ratios, as calculated in accordance with our debt covenant includes standby letters of credit, surety bonds and excludes other comprehensive income pension adjustments. 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,	
	2011	2010	**2011**	2010
Debt-to-capitalization ratio	**58%**	58%	**60%**	n/a

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. We were in compliance with all existing debt provisions and covenants, both financial and non-financial, as of December 31, 2011 and 2010.

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 trigger events in our debt instruments that are tied to changes in our specified credit ratings or our stock price and have not entered into any transaction that requires us to issue equity based on credit ratings or other trigger events.

Preferred Securities

At December 31, 2011 and 2010, 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. In 2010, we spent $7 million to purchase approximately 0.2 million treasury shares at a weighted average price per share of $36.01.

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 comprehensive income (loss) includes net income and net income attributable to AGL Resources Inc. 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 and net income attributable to AGL Resources Inc. For more information on our derivative instruments, see Note 5. For more information on our pensions and retirement benefit obligations, see Note 6. Our 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	Derivative instruments[1]	Pension & other retirement obligations[2]	Accumulated other comprehensive income (loss)
As of Dec. 31, 2008	$ (3)	$(131)	$(134)
Other comprehensive income	1	17	18
As of Dec. 31, 2009	(2)	(114)	(116)
Other comprehensive loss	(5)	(28)	(33)
Purchase of additional 15% ownership interest in SouthStar	(1)	—	(1)
As of Dec. 31, 2010	(8)	(142)	(150)
Other comprehensive loss	(2)	(65)	(67)
As of Dec. 31, 2011	$(10)	$(207)	$(217)

[1] Income taxes for the years ending December 31, 2011, 2010 and 2009 were immaterial.

[2] Income taxes for the years ending December 31, 2011, 2010 and 2009 were $41 million, $20 million and $10 million, respectively.

Note 10 Non-Wholly Owned Entities

As of December 31, 2011, we had ownership interests in SouthStar, Triton, Horizon Pipeline and Sawgrass Storage.

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 2011, 2010 and 2009 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 retail customers primarily in Georgia, and under various other trade names to retail customers in Ohio, Florida and New York and to commercial and industrial customers, principally in Alabama, Florida, North Carolina, South Carolina and Tennessee. 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, 2011 and 2010. 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, 2011, 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 approximately $56 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 $2 million for 2011, $3 million for 2010 and $2 million for 2009. 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, 2011, SouthStar distributed $16 million to Piedmont and $27 million during the year ended December 31, 2010. The decrease of $11 million was primarily the result of our increased ownership percentage of SouthStar in 2010.

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

	December 31, 2011			December 31, 2010		
In millions	Consolidated	SouthStar[1]	%[2]	Consolidated	SouthStar[1]	%[2]
Current assets	**$ 2,746**	**$210**	**8%**	$2,166	$239	11%
Long-term assets and other deferred debits	**11,167**	**9**	**—**	5,354	9	—
Total assets	**$13,913**	**$219**	**2%**	$7,520	$248	3%
Current liabilities	**$ 3,084**	**$ 77**	**2%**	$2,432	$ 93	4%
Long-term liabilities and other deferred credits	**7,490**	**—**	**—**	3,252	—	—
Total Liabilities	**10,574**	**77**	**1**	5,684	93	2
Equity	**3,339**	**142**	**4**	1,836	155	8
Total liabilities and equity	**$13,913**	**$219**	**2%**	$7,520	$248	3%

[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.

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, 2011, we had invested in seven tranches established by Triton.

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.

Sawgrass Storage We have a 50% owned joint venture with Samson Contour Energy that is currently in its development stage. The purpose of the joint venture is to develop, operate and market the services of a natural gas storage and pipeline facility in Louisiana.

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

In millions	2011
Triton	$ 76
Horizon Pipeline	18
Other	8
Total	$102

Our net equity investment income for the twelve months ended December 31, 2011, was approximately $1 million. During the same period, we received an immaterial amount of dividends from our equity investees.

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, 2011.

In millions	Total	2012	2013	2014	2015	2016	2017 & thereafter
Recorded contractual obligations:							
Long-term debt[1]	$3,431	$ —	$225	$ —	$200	$545	$2,461
Short-term debt[2]	1,338	1,338	—	—	—	—	—
Pipeline replacement program costs[3]	276	131	145	—	—	—	—
Environmental remediation liabilities[3]	327	37	66	55	45	32	92
Total	$5,372	$1,506	$436	$ 55	$245	$577	$2,553
Unrecorded contractual obligations and commitments[4][5][10]:							
Pipeline charges, storage capacity and gas supply[5]	$2,263	$781	$494	$269	$164	$ 85	$ 470
Interest charges[6]	2,581	169	161	158	149	137	1,807
Operating leases[7]	220	32	25	20	19	18	106
Asset management agreements[8]	26	11	9	3	2	1	—
Standby letters of credit, performance / surety bonds[9]	22	18	4	—	—	—	—
Other	14	5	3	2	2	2	—
Total	$5,126	$1,016	$696	$452	$336	$243	$2,383

[1] Excludes the $99 million step up to fair value of first mortgage bonds, $18 million unamortized debt premium and $13 million interest rate swaps fair value adjustment.

[2] Includes current portion of long-term debt of $15 million, which matures in June 2012 and current portion of capital leases.

[3] Includes charges recoverable through rate rider mechanisms.

[4] In accordance with GAAP, these items are not reflected in our Consolidated Statements of Financial Position.

[5] 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 67 Bcf at floating gas prices calculated using forward natural gas prices as of December 31, 2011, and is valued at $222 million. As we do for other subsidiaries, we provide guarantees to certain gas suppliers for SouthStar in support of payment obligations.

[6] Floating rate interest charges are calculated based on the interest rate as of December 31, 2011 and the maturity date of the underlying debt instrument. As of December 31, 2011, we have $61 million of accrued interest on our Consolidated Statements of Financial Position that will be paid in 2012.

[7] 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.

[8] Represent fixed-fee minimum payments for Sequent's affiliated asset management agreements.

[9] We provide guarantees to certain municipalities and other agencies and certain gas suppliers of SouthStar in support of payment obligations.

[10] Based on the current funding status of the plans, we would be required to make a minimum contribution to our pension plans of approximately $36 million in 2012. We may make additional contributions in 2012.

Substitute Natural Gas

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 counterparty intends to construct a 60 Bcf per year coal gasification plant in southern Illinois. The project is expected to be financed by the counterparty with external debt and equity. In addition, the final price of the SNG may exceed market prices and is dependent upon a variety of factors, including plant construction costs, and is not estimable. The price of the SNG under this contract could potentially be significantly more than market price. However, this agreement complies with an Illinois statute that authorizes full recovery of the purchase costs; therefore we expect to recover such costs. Since the purchase agreement is contingent upon various milestones to be achieved by the counterparty to the agreement, our obligation is not certain at this time. While the purchase agreement is a variable interest in the counterparty, we have concluded, based on a qualitative evaluation, that we are not the primary beneficiary required to consolidate the counterparty. No amount has been recognized on our Statement of Financial Position in connection with the purchase agreement.

On October 11, 2011, the Illinois Power Agency (IPA) approved the form of a draft 30-year contract for the purchase of 20 Bcf per year of SNG from a second proposed plant beginning as early as 2018. In November 2011, Nicor Gas 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 Illinois Commission issued an order on January 10, 2012 approving a final form of contract for the second plant. The final form of contract approved by the Illinois Commission modified the draft contract submitted by the IPA in various respects. Both we and the developer of the plant have filed applications for rehearing with the Illinois Commission seeking changes to the final form of contract it approved.

The price of the SNG that may be produced from both of the coal gasification plants may significantly exceed market prices and is dependent upon a variety of factors, including plant construction costs, and is currently not estimable. Illinois laws provided that prices paid for SNG purchase from the plants are to be considered

prudent and not subject to review or disallowance by the Illinois Commission. No amount has been recognized on our Statement of Financial Position in connection with this contract.

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 approximately $76 million at December 31, 2011. We believe the likelihood of any such payment by TEL is remote. No liability has been recorded for this obligation.

Performance guarantees Nicor Services markets product warranty contracts that provide for the repair of heating, ventilation and air conditioning equipment, natural gas lines and other appliances within homes. Revenues from these product warranty contracts are recognized ratably over the coverage period, and related repair costs are charged to expense as incurred.

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	Cost estimate range	Amount recorded	Expected costs over next twelve months
Illinois	$134 – $216	$134	$19
Georgia and Florida	42 – 98	58	7
New Jersey	124 – 174	124	9
North Carolina	10 – 16	11	2
Total	$310 – $504	$327	$37

We have confirmed 14 former operating sites in Georgia and Florida where Atlanta Gas Light, or its predecessors, owned or operated all or part of these sites. As of December 31, 2011, 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. 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 these sites. 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. We have also identified a site in North Carolina, which 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.

We have identified 26 sites in Illinois for which we 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 51.73% of cleanup costs for 23 sites, no portion of the cleanup costs for 14 other sites and 50% of general remediation program costs that do not relate exclusively to particular sites. In addition to the sites from the agreement with Commonwealth Edison Company there are 3 sites in which we have sole responsibility. Information regarding preliminary site reviews has been presented to the Illinois Environmental Protection Agency for certain sites. More detailed investigations and remedial activities are complete, in progress or planned at many of these sites.

Our ERC liabilities are customarily reported estimates of future remediation costs for our former operating sites that are contaminated based on probabilistic models of potential costs and on an undiscounted basis. However, we have not yet performed these probabilistic models for all of our sites in Illinois, which will be completed in 2012. The results of the detailed site-by-site investigations will determine the extent additional remediation is necessary and provide a basis for estimating additional future costs. As of December 31, 2011, we had recorded a liability in connection with these matters of $134 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.

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 $7 million in revenues over the next 12 months which is reflected as a current asset. We recovered $11 million in 2011, $13 million in 2010 and $20 million in 2009 from our ERC rate riders.

Litigation

We are involved in litigation arising in the normal course of business. Although in some cases the company is 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 the company 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.

SouthStar Litigation In February 2008, a class action lawsuit was filed in the Superior Court of Fulton County in the State of Georgia against Georgia Natural Gas alleging that it charged its customers of variable rate plans prices for natural gas that were in excess of the published price, failed to give proper notice regarding the availability of potentially lower price plans and that it changed its methodology for computing variable rates. Georgia Natural Gas asserts that no violation of law or Georgia Commission rules has occurred. This lawsuit was dismissed in September 2008. The plaintiffs appealed the dismissal of the lawsuit and, in May 2009, the Georgia Court of Appeals reversed the lower court's order. In June 2009, Georgia Natural Gas filed a petition for reconsideration with the Georgia Supreme Court. In October 2009 the Georgia Supreme Court agreed to review the Court of Appeals' decision. Accordingly, the Georgia Supreme Court held oral arguments in January 2010. In March 2010 the Georgia Supreme Court upheld the Court of Appeals' decision. A settlement agreement was reached with the plaintiffs' in December 2011. SouthStar asserts that no violation of law or Georgia Commission rules has occurred, however they agreed to settle in order to avoid the further expense and inconvenience of litigation.

Litigation Related to the Nicor Merger We were named as a defendant in several class action lawsuits brought by purported Nicor shareholders challenging Nicor's merger with us. The complaints alleged that we aided and abetted alleged breaches of fiduciary duty by Nicor's Board of Directors. The shareholder actions sought, among other things, declaratory and injunctive relief, including orders enjoining the defendants from completing the merger and, in certain circumstances, damages. This lawsuit was settled on December 7, 2011.

PBR Proceeding Nicor Gas' PBR plan for natural gas costs went into effect in 2000 and was terminated 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 PBR 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, the staff of the Illinois Commission and CUB entered into a stipulation 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, 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, we 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 includes crediting Nicor Gas customers $64 million, but does not constitute an admission of fault. This resulted in a $37 million adjustment to the previously recorded $27 million liability referenced above. The stipulated resolution 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 the proceeding. Evidentiary hearings, on this matter are scheduled to begin on February 28, 2012. The $64 million proposed credit is consistent with the estimated liability we recorded for this matter as part of our accounting for the merger with Nicor.

We are unable to predict the outcome of the Illinois Commission's review or our potential exposure thereunder. Since the PBR plan and historical gas costs are still under Illinois Commission review, the final outcome could be materially different than the amounts reflected in our financial statements as of December 31, 2011.

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. A number of municipalities have instituted audits of Nicor Gas' tax remittances. In May 2007, five of those municipalities filed an action against Nicor Gas in state court in DuPage County, Illinois relating to these tax audits. Following a dismissal of this action without prejudice by the trial court, the municipalities filed an amended complaint. The amended complaint seeks, among other things, compensation for alleged unpaid taxes. We are contesting the claims in the amended complaint. In December 2007, 25 additional municipalities, all represented by the same audit firm involved in the lawsuit, issued assessments to Nicor Gas claiming that it failed to provide information requested by the audit firm and owed the municipalities back taxes. We believe the assessments are improper and have challenged them. 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 these matters is not expected to have a material adverse impact on our liquidity or financial condition.

On February 8, 2010, the IAGO issued a subpoena to Nicor Gas to provide documents in connection with an IAGO investigation pursuant to the Illinois Whistleblower Reward and Protection Act. On November 30, 2010, the IAGO issued Nicor Gas an amended request for information. According to the subpoena, the IAGO

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.

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, 2011	2010
Accumulated deferred income tax liabilities		
Property – accelerated depreciation and other property-related items	**$1,418**	$863
Mark to market	**22**	11
Investments in partnerships	**42**	—
Other	**91**	—
Acquisition intangibles	**34**	—
Undistributed earnings of foreign subsidiaries	**39**	—
Total accumulated deferred income tax liabilities	**1,646**	874
Accumulated deferred income tax assets		
Deferred investment tax credits	**10**	4
Unfunded pension and other retirement benefit obligation	**137**	94
Other	**57**	11
Total accumulated deferred income tax assets	**204**	109
Valuation allowances[1]	**(3)**	(3)
Total accumulated deferred income tax assets, net of valuation allowance	**201**	106
Net accumulated deferred tax liability	**$1,445**	$768

[1] Valuation allowance is due to the net operating losses on a former non-operating subsidiary that are not allowed in New Jersey.

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, 2011, we had approximately $39 million of deferred income tax liabilities related to approximately $104 million of cumulative undistributed earnings of our foreign subsidiaries. We have not recorded deferred income taxes of approximately $31 million on approximately $89 million of cumulative undistributed foreign earnings.

Tax Benefits

As of December 31, 2011 and December 31, 2010, we did not have a liability for unrecognized tax benefits. Based on current information, we do not anticipate that this will change materially in 2012. As of December 31, 2011, 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 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 includes natural gas asset management and related logistics activities for each of our utilities as well as for nonaffiliated companies, natural gas storage arbitrage and related activities. Our midstream operations segment includes 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. The cargo shipping segment also includes amounts related to cargo insurance coverage sold to its customers and other third parties. The 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 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 are 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 2011, 2010 and 2009 are presented below.

In millions	2011	2010	2009
Operating income	**$440**	$500	$476
Other income (expense)	**7**	(1)	9
EBIT	**447**	499	485
Interest expense	**136**	109	101
Earnings before income taxes	**311**	390	384
Income taxes	**125**	140	135
Net income	**$186**	$250	$249

Summarized Statements of Income, Statements of Financial Position and capital expenditure information by segment as of and for the years ended December 31, 2011, 2010 and 2009 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.

In millions	Distribution operations	Retail operations	Wholesale services	Midstream operations	Cargo shipping	Other and intercompany eliminations[4]	Consolidated
2011							
Operating revenues from external parties	**$ 1,451**	**$702**	**$ 95**	**$ 70**	**$ 19**	**$ 1**	**$ 2,338**
Intercompany revenues[1]	**146**	**—**	**3**	**—**	**—**	**(149)**	**—**
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**	**(13)**	**490**
Depreciation and amortization	**160**	**2**	**1**	**10**	**1**	**12**	**186**
Nicor merger expenses[2]	**—**	**—**	**—**	**—**	**—**	**68**	**68**
Taxes other than income taxes	**44**	**2**	**3**	**3**	**—**	**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**	**—**	**—**	**—**	**1**	**—**	**7**
EBIT	**$ 412**	**$ 93**	**$ 5**	**$ 9**	**$ —**	**$ (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**	**$ —**	**$ 24**	**$ 427**

Notes to Consolidated Financial Statements

In millions	Distribution operations	Retail operations	Wholesale services	Midstream operations	Cargo shipping	Other and intercompany eliminations[4]	Consolidated
2010							
Operating revenues from external parties	$1,349	$840	$ 121	$ 46	$—	$ 17	$2,373
Intercompany revenues[1]	145	—	—	—	—	(145)	—
Total operating revenues	1,494	840	121	46	—	(128)	2,373
Operating expenses							
Cost of goods sold	615	657	16	16	—	(140)	1,164
Operation and maintenance	358	76	52	17	—	(6)	497
Depreciation and amortization	138	2	2	5	—	13	160
Nicor merger expenses[2]	—	—	—	—	—	6	6
Taxes other than income taxes	35	2	3	2	—	4	46
Total operating expenses	1,146	737	73	40	—	(123)	1,873
Operating income (loss)	348	103	48	6	—	(5)	500
Other income (expense)	4	—	1	—	—	(6)	(1)
EBIT	$ 352	$103	$ 49	$6	$—	$ (11)	$499
Identifiable and total assets[3]	$5,484	$259	$1,326	$471	$—	$ (20)	$7,520
Goodwill	$ 404	$ —	$ —	$ 14	$—	$ —	$ 418
Capital expenditures	$ 357	$ 3	$ 2	$126	$—	$ 22	$ 510

In millions	Distribution operations	Retail operations	Wholesale services	Midstream operations	Cargo shipping	Other and intercompany eliminations[4]	Consolidated
2009							
Operating revenues from external parties	$1,348	$801	$ 121	$ 22	$—	$ 25	$2,317
Intercompany revenues[1]	138	—	—	—	—	(138)	—
Total operating revenues	1,486	801	121	22	—	(113)	2,317
Operating expenses							
Cost of goods sold	646	620	10	—	—	(134)	1,142
Operation and maintenance	352	71	59	15	—	—	497
Depreciation and amortization	135	4	3	3	—	13	158
Nicor merger expenses[2]	—	—	—	—	—	—	—
Taxes other than income taxes	35	1	2	1	—	5	44
Total operating expenses	1,168	696	74	19	—	(116)	1,841
Operating income (loss)	318	105	47	3	—	3	476
Other income (expense)	9	—	—	—	—	—	9
EBIT	$ 327	$105	$ 47	$3	$—	$3	$ 485
Identifiable and total assets[3]	$5,222	$261	$1,168	$332	$—	$ 96	$7,079
Goodwill	$ 404	$ —	$ —	$ 14	$—	$ —	$ 418
Capital expenditures	$ 354	$ 2	$ 1	$110	$—	$ 9	$ 476

[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 $449 million in 2011, $473 million in 2010 and $425 million in 2009.

[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 2011, 2010 and 2009 are summarized below. The variance in our quarterly earnings is the result of the seasonal nature of our primary business.

In millions, except per share amounts	March 31	June 30	Sept. 30	Dec. 31
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
2009				
Operating revenues	$ 995	$ 377	$ 307	$ 638
Operating income	230	55	43	148
Net income attributable to AGL Resources Inc.	119	20	12	71
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	1.55	0.26	0.16	0.92
Diluted earnings per share attributable to AGL Resources Inc. common shareholders	1.55	0.26	0.16	0.92

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, 2011, 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

Other than changes resulting from the Nicor merger discussed below, there were no changes in our internal control over financial reporting that occurred during the fourth quarter ended December 31, 2011, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

On December 9, 2011, we completed our merger with Nicor. As permitted by the Securities and Exchange Commission, management has elected to exclude Nicor from management's assessment of the effectiveness of our internal control over financial reporting for the year ended December 31, 2011.

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, 2011. 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 56	
Chairman, President and Chief Executive Officer	October 2007 – Present
President and Chief Executive Officer	March 2006 – October 2007
Ralph Cleveland, Age 49	
Executive Vice President and President, Nicor Gas	December 2011 – Present
Executive Vice President, Engineering and Operations	December 2008 – December 2011
Senior Vice President, Engineering and Operations	February 2005 – December 2008
Andrew W. Evans, Age 45	
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 51	
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 57	
Executive Vice President and Chief People Officer	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 54	
Executive Vice President, General Counsel and Chief Ethics and Compliance Officer	September 2005 – Present
Peter I. Tumminello, Age 49	
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 1 – Election of Directors", – "Corporate Governance - Ethics and Compliance Program," – "Committees of the Board" and "– Audit Committee" in the Proxy Statement for our 2012 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 "Share Ownership" and "Executive Compensation – Equity Compensation Plan Information" in the Proxy Statement or subsequent amendment referred to in Item 10 above. All such information that is provided in the Proxy Statement is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions and Director Independence

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

Item 14. Principal 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 2012" 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, 2011 and 2010
- Consolidated Statements of Income for the years ended December 31, 2011, 2010 and 2009
- Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2011, 2010 and 2009
- Consolidated Statements of Equity for the years ended December 31, 2011, 2010 and 2009
- Consolidated Statements of Cash Flows for the years ended December 31, 2011, 2010 and 2009
- 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, 2011.

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

The Commission file number reference for any exhibit incorporated by reference is 001-14174 unless otherwise indicated.

2.1 Agreement and Plan of Merger 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 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, as amended on December 9, 2011 (Exhibit 3.2, AGL Resources Inc. Form 8-K filed December 13, 2011).

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).

PART IV

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, 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, 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, No. 333-69500).

4.12 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.a 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.b 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.c 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.d 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.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 4.10, 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 4.11, 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, 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.h 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.i 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.j 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).

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.c, 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.

10.1.ag Form of Restricted Stock Agreement under Omnibus Performance Incentive Plan, as Amended and Restated.

10.1.ah 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.ai 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.aj 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.ak 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.al 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.am 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.an 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.ao 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.ap 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.aq 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.ar 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.as Forms of Nonqualified Stock Option Agreement without the reload provision (LTIP and Officer Plan) (Exhibit 10.1, AGL Resources Inc. Form 8-K filed March 18, 2005).

10.1.at Form of Nonqualified Stock Option Agreement with the reload provision (Officer Plan) (Exhibit 10.2, AGL Resources Inc. Form 8-K filed March 18, 2005).

10.1.au 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.av 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.aw Form of AGL Resources Inc. Annual Incentive Plan.

10.1.ax 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.ay 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.az 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.ba 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, 2010) 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 3, 2011 filed on March 14, 2011).

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).

10.6.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 Bridge Term Loan Credit Agreement dated as of December 21, 2010 among AGL Resources, Inc., AGL Capital Corporation, Goldman Sachs Bank USA, as administrative agent, sole lead arranger and sole bookrunner, SunTrust Bank, N.A. and Wells Fargo Bank, National Association, as co-syndication agents, Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as co-documentation agents, and the several lenders named therein (Exhibit 10.1, AGL Resources Inc. Form 8-K filed December 23, 2010).

10.11.b First Amendment as of August 11, 2011 to Bridge Term Loan Credit Agreement as of December 21, 2010 by and among AGL Capital Corporation, AGL Resources Inc., Goldman Sachs Bank USA, as administrative agent, and the several lenders named therein (Exhibit 10.2, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2011).

10.11.c Guarantee, dated as of December 21, 2010, made by AGL Resources Inc. in favor of Goldman Sachs Bank USA, as administrative agent for the several banks and other financial institutions or entities from time to time party to the Bridge Term Loan Credit Agreement dated as of the date thereof, among AGL Resources Inc., AGL Capital Corporation, the Lenders, and Goldman Sachs Bank USA, as Administrative Agent (Exhibit 10.2, AGL Resources Inc. Form 8-K filed December 23, 2010).

10.12.a Term Loan Credit Agreement dated as of December 21, 2010 among AGL Resources, Inc., AGL Capital Corporation, Goldman Sachs Bank USA, as administrative agent, sole lead arranger and sole bookrunner, JPMorgan Chase Bank, N.A. and Bank of America, N.A., as co-syndication agents, The Royal Bank of Scotland PLC and Morgan Stanley Senior Funding, Inc., as co-documentation agents, and the several lenders named therein. (Exhibit 10.3, AGL Resources Inc. Form 8-K filed December 23, 2010).

10.12.b Guarantee, dated as of December 21, 2010, made by AGL Resources Inc. in favor of Goldman Sachs Bank USA, as administrative agent for the several banks and other financial institutions or entities from time to time party to the Term Loan Credit Agreement dated as of the date thereof, among AGL Resources Inc., AGL Capital Corporation, the Lenders, and Goldman Sachs Bank USA, as Administrative Agent (Exhibit 10.4, AGL Resources Inc. Form 8-K filed December 23, 2010).

10.13.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).

10.13.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., 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).

10.13.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., 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).

10.14.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).

10.14.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 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).

10.14.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 10.5, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2011).

10.15.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).

10.15.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).

10.15.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).

10.16.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).

10.16.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).

10.16.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).

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.[1]

101.SCH XBRL Taxonomy Extension Schema.[1]

101.CAL XBRL Taxonomy Extension Calculation Linkbase.[1]

101.DEF XBRL Taxonomy Definition Linkbase.[1]

101.LAB XBRL Taxonomy Extension Labels Linkbase.[1]

101.PRE XBRL Taxonomy Extension Presentation Linkbase.[1]

[1] Furnished, not filed

Attached as Exhibit 101 to this Annual Report are the following documents formatted in extensible business reporting language (XBRL): (i) Document and Entity Information; (ii) Consolidated Statements of Financial Position at December 31, 2011 and 2010; (iii) Consolidated Statements of Income for the years ended December 31, 2011, 2010 and 2009; (iv) Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2011, 2010 and 2009; (v) Consolidated Statements of Equity for the years ended December 31, 2011, 2010 and 2009; (vi) Consolidated Statements of Cash Flows for the years ended December 31, 2011, 2010 and 2009; and (vii) Notes to Consolidated Financial Statements.

Pursuant to Rule 406T of Regulation S-T, these interactive data files are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933 or Section 18 of the Securities Exchange Act of 1934 and otherwise are not subject to liability. We also make available on our web site the Interactive Data Files submitted as Exhibit 101 to this Annual Report.

(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 7, 2012.

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, 2011, 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 7, 2012.

Signature, title

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

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

/s/ Bryan E. Seas
Senior Vice President and
Chief Accounting Officer
(Principal Accounting Officer)

Signature, title

/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

Signature, title

/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, 2011.

Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts	Deductions	Balance at end of period
2009					
Allowance for uncollectible accounts	$16	$25	$–	$(27)	$14
Income tax valuation	3	–	–	–	3
2010					
Allowance for uncollectible accounts	$14	$22	$–	$(20)	$16
Income tax valuation	3	–	–	–	3
2011					
Allowance for uncollectible accounts	**$16**	**$20**	**$–**	**$(19)**	**$17**
Income tax valuation	**3**	**–**	**–**	**–**	**3**

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

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 22, 2012

/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)

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 22, 2012

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

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

Ralph Cleveland
Executive Vice President and President, Nicor Gas

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 Information
A copy of this Annual Report, as well as our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, other reports that we file with or furnish to the Securities and Exchange Commission (SEC) and our recent news releases are available free of charge 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 2011 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, 2011	2010
Diluted earnings per share - as reported	$2.12	$3.00
Transaction costs of Nicor merger	0.80	0.05
Dilute earnings per share - as adjusted	$2.92	$3.05

ANNUAL MEETING

The 2012 annual meeting of shareholders will be held Tuesday, May 1, 2012, 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, 2012, there were 17,770 record holders of our common stock. Quarterly information concerning our high and low stock prices and cash dividends paid in 2011 and 2010 is as follows:

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] 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.

2010

	Sales price of common stock			Cash dividend per
Quarter ended	High	Low	Close	common share
March 31, 2010	$38.83	$34.26	$38.65	$0.44
June 30, 2010	40.08	34.72	35.82	0.44
September 30, 2010	40.00	35.29	38.36	0.44
December 31, 2010	39.66	34.21	35.85	0.44

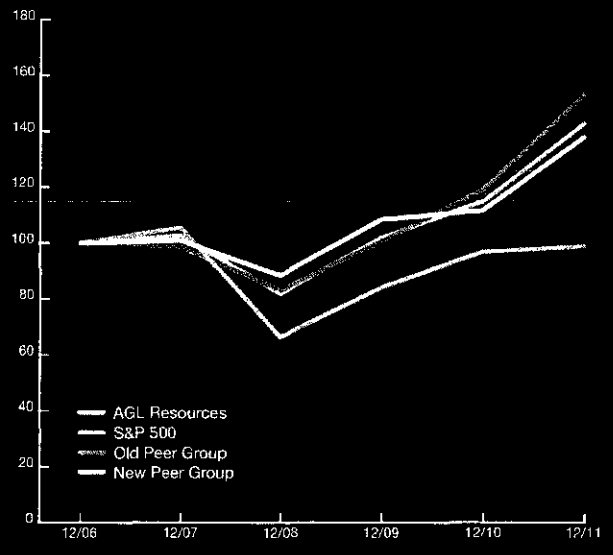
We have historically paid dividends to common shareholders four times a year: March 1, June 1, September 1 and December 1. We have paid 257 consecutive quarterly dividends beginning in 1948. Our common shareholders may receive dividends when declared at the discretion of our Board of Directors, and payment of future dividends will depend on our future earnings, cash flow, financial requirements and other factor. In February 2012 we paid a stub dividend of $0.3611 per share, the remaining quarterly dividends in 2012 will be $0.46 per share.

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COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN*

The performance graph below compares the yearly percentage change in our total return to shareholders for the last five years with the total return of the Standard & Poor's 500 Stock Index, the cumulative total return of two different customized peer company groups, the new self-determined peer group and the old self-determined peer group. The new self-determined peer group includes Sempra Energy and Vectren Corp. and excludes Northwest Natural Gas Company because our Board of Directors determined, in part due to the merger with Nicor Inc., that Sempra Energy and Vectren Corp. better fit the profile of the companies in the peer group, which is composed of a hybrid group of utility companies, primarily natural gas distribution companies, with similar revenue, market capitalization and asset base.

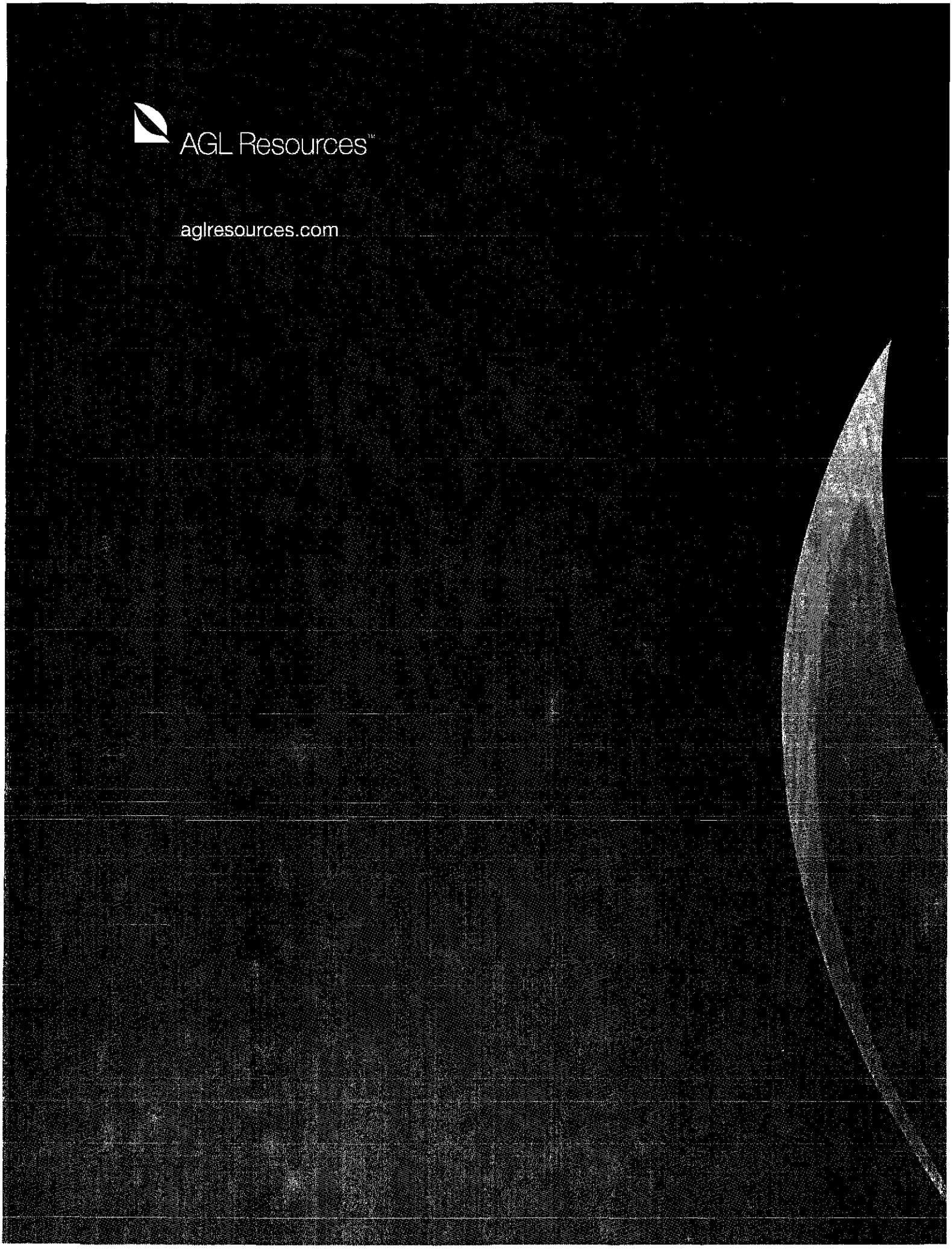
The new self-determined peer group was recommended by a global management consulting firm and approved by our Board of Directors. There are 12 companies included in this new self-determined peer group: Atmos Energy Corp., Centerpoint Energy Inc., Integrys Energy Group Inc., New Jersey Resources Corp., NiSource Inc., Oneok Inc., Piedmont Natural Gas Company Inc., Sempra Energy, Southwest Gas Corp., UGI Corp., Vectren Corp. and WGL Holdings Inc. There are 11 companies included in the old self-determined peer group: Atmos Energy Corp., Centerpoint Energy Inc., Integrys Energy Group Inc., New Jersey Resources Corp., NiSource Inc., Northwest Natural Gas Company, Piedmont Natural Gas Company Inc., Southwest Gas Corp., UGI Corp. and WGL Holdings Inc.



	12/06	12/07	12/08	12/09	12/10	12/11
AGL Resources Inc	100.00	100.84	88.33	108.30	111.55	137.89
S&P 500	100.00	105.49	66.46	84.05	96.71	98.75
Old Peer Group	100.00	98.49	83.15	100.30	119.03	153.29
New Peer Group	100.00	102.62	81.89	101.76	114.75	142.71

Source: Research Data Group

* $100 invested on 12/31/06 in stock or index, including reinvestment of dividends. Fiscal year ending December 31.


AGL Resources™
aglresources.com



WE'RE STANDING ON THE

★ *Solution* ★

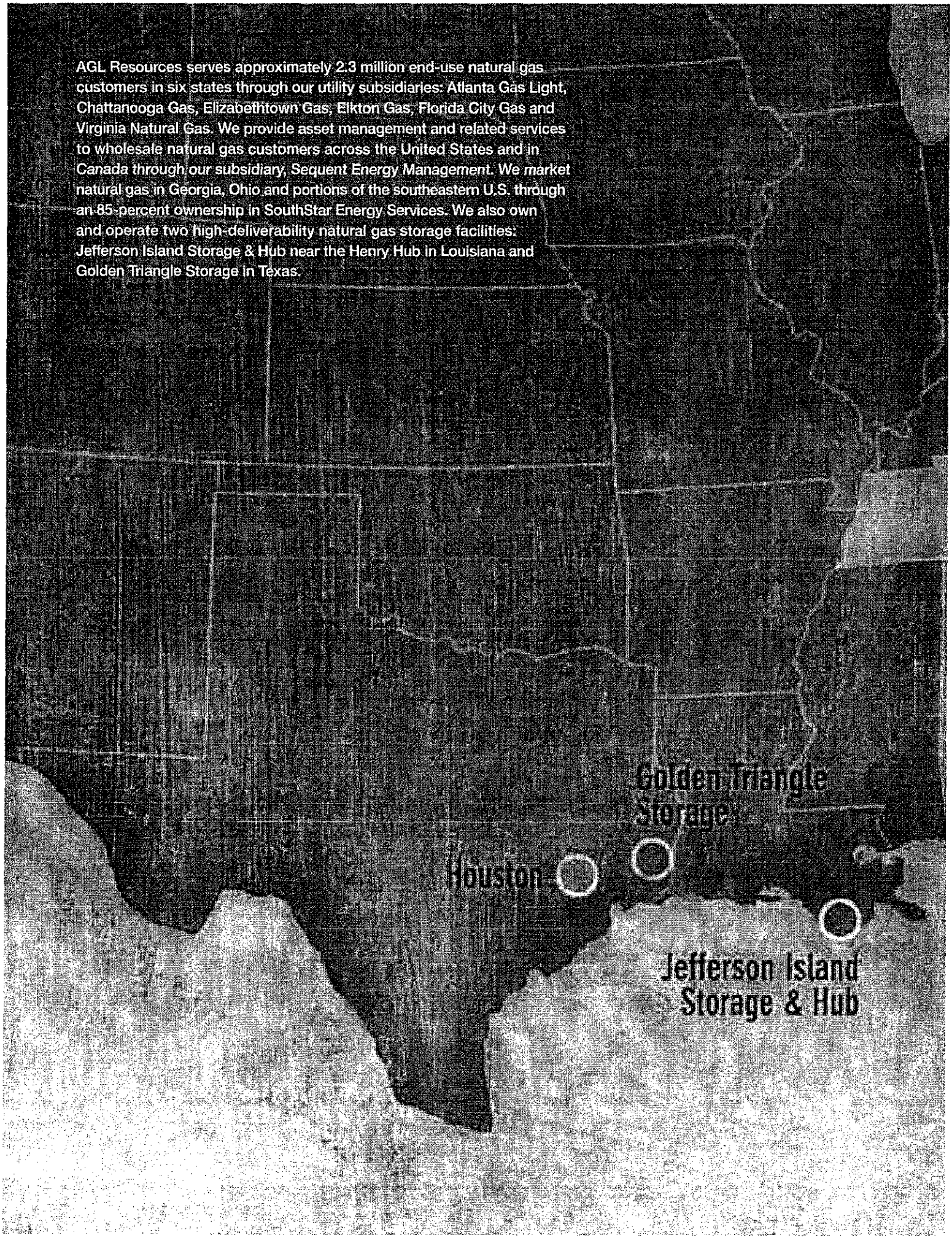
ANNUAL REPORT 2010

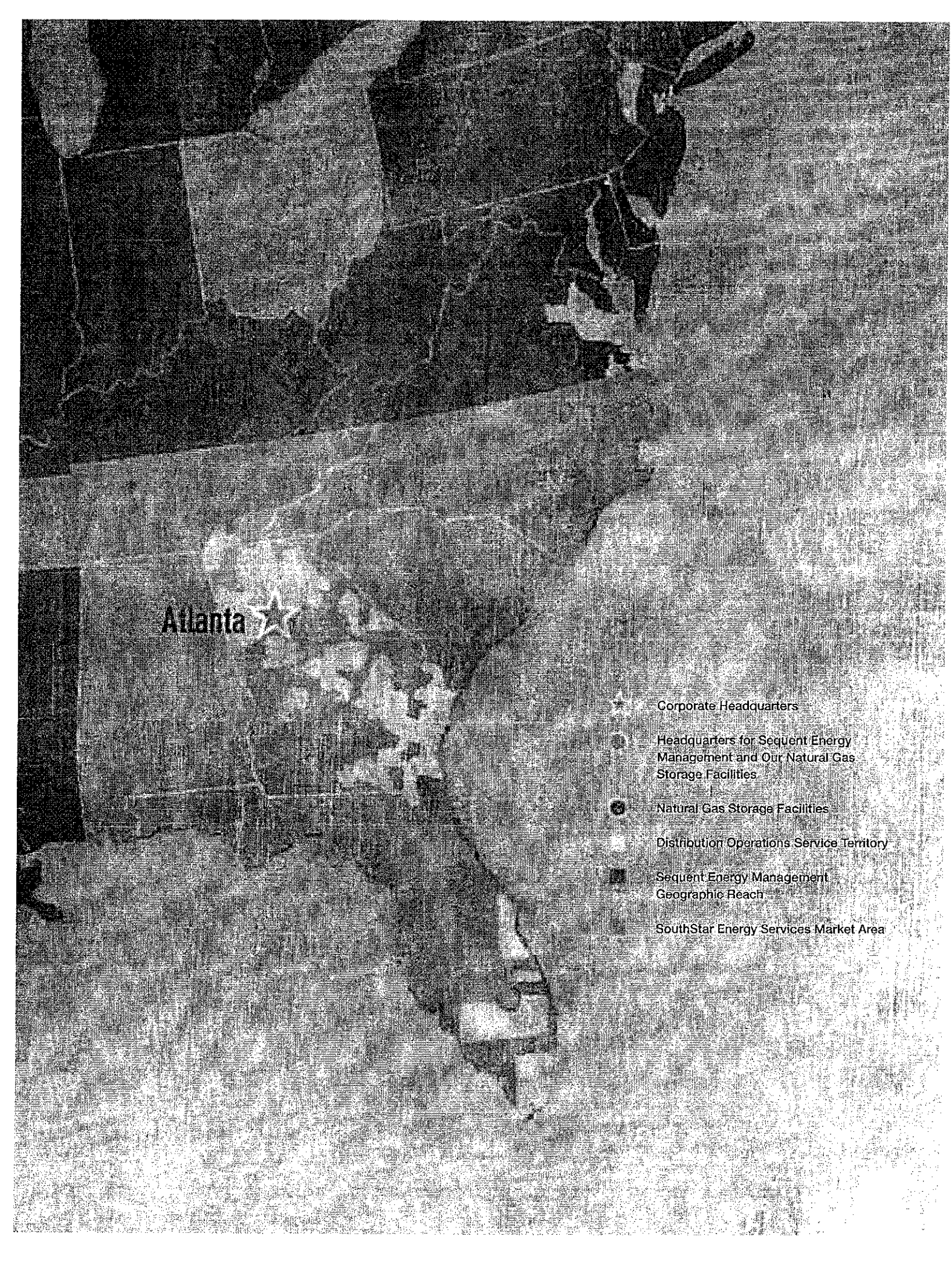
AGL Resources

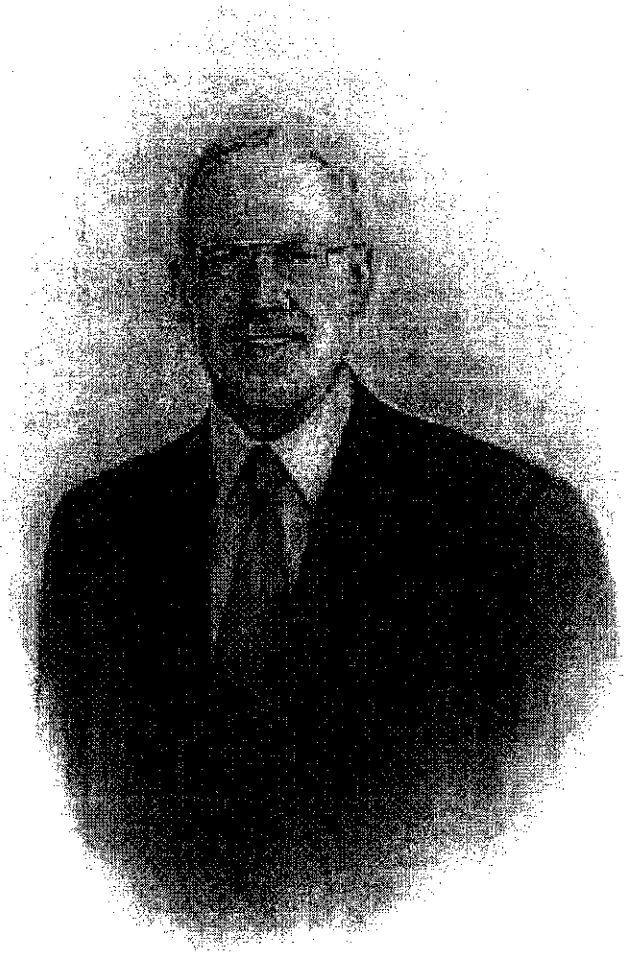
How can America fuel the energy needs of current and future generations? We are standing on the solution.

At AGL Resources, we have served our customers with safe, efficient, reliable natural gas for more than 150 years. Our portfolio of regulated and nonregulated companies is well positioned to ensure Americans reap the full benefits – environmental friendliness, efficiency and versatility – of this abundant and domestic energy source for generations to come.

AGL Resources serves approximately 2.3 million end-use natural gas customers in six states through our utility subsidiaries: Atlanta Gas Light, Chattanooga Gas, Elizabethtown Gas, Elkton Gas, Florida City Gas and Virginia Natural Gas. We provide asset management and related services to wholesale natural gas customers across the United States and in Canada through our subsidiary, Sequent Energy Management. We market natural gas in Georgia, Ohio and portions of the southeastern U.S. through an 85-percent ownership in SouthStar Energy Services. We also own and operate two high-deliverability natural gas storage facilities: Jefferson Island Storage & Hub near the Henry Hub in Louisiana and Golden Triangle Storage in Texas.




Atlanta
Corporate Headquarters
Headquarters for Sequent Energy Management and Our Natural Gas Storage Facilities
Natural Gas Storage Facilities
Distribution Operations Service Territory
Sequent Energy Management Geographic Reach
SouthStar Energy Services Market Area



☆ TO OUR *Shareholders* ☆

As we reflect on a record-setting 2010 and look toward the future, AGL Resources remains committed to our core strategy: maximizing shareholder value by maintaining a long-term focus on the fundamentals of our business. During 2010, we built upon our strong track record of significant operational achievements at both our regulated utilities and non-utility businesses. We also maintained our focus on expense discipline while opportunistically investing in businesses and partnerships with an eye on long-term growth.

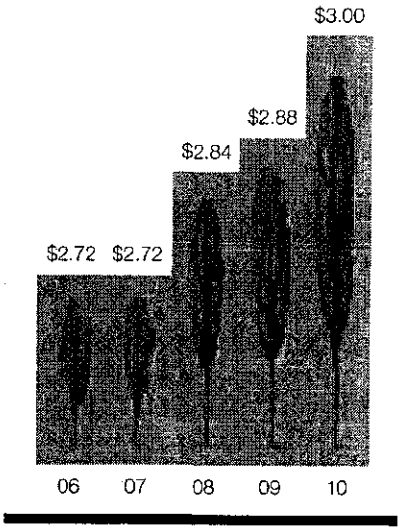
By consistently applying these principles, and with the worst of the 2008-2009 global financial crisis seemingly behind us, AGL Resources is well positioned to take full advantage of our broad set of opportunities in 2011 and beyond.

* Our balanced and diversified portfolio of businesses continues to deliver steady performance;
* We expect to expand our national presence for both our utility and non-utility businesses with our announced acquisition of Nicor; and
* More broadly, the versatility of natural gas and its many benefits offer ongoing opportunities to leverage our core competencies in new gas-related markets.

RECORD FINANCIAL RESULTS

AGL Resources achieved record financial results in 2010, with diluted earnings per share (EPS) of $3.00 on a GAAP basis. Excluding $4 million in after-tax merger costs related to the proposed Nicor transaction, diluted EPS were $3.05 on a non-GAAP basis, an increase of 6 percent over 2009 results[1]. This growth reflects strong operating performance in each of our business units during the year. In an environment where we have recently experienced historically low levels of price volatility in the natural gas market, these are especially significant accomplishments.

DILUTED EARNINGS PER SHARE



AGL Resources has long maintained a policy of increasing dividends in line with earnings – and 2010 was no exception. We paid cash dividends of $1.76 per share in 2010, including a 2.3 percent dividend increase that was approved by our Board of Directors in February 2010. The company's quarterly dividend announced on Oct. 28, 2010, marked the 252nd consecutive quarterly dividend the company has paid since 1948.

For the fiscal year 2010, AGL Resources generated a total shareholder return of 3 percent, including the highest dividend yield of the major local distribution companies in our peer group.

During 2010, we successfully completed nearly $1.2 billion of refinancing activity, including the renewal of our $1 billion senior credit facility that supports our commercial paper program, and the refinancing of $160 million in credit facilities backing our outstanding revenue bonds. As a result, we continue to maintain a strong balance sheet, ample liquidity and good access to the capital markets. In addition, to support the proposed acquisition of Nicor, we successfully established and syndicated a $1.05 billion bridge facility that we anticipate will be replaced with long-term debt financing prior to closing the acquisition.

[1] *Please visit the Investor Relations section of our website at aglresources.com for a reconciliation to GAAP.*

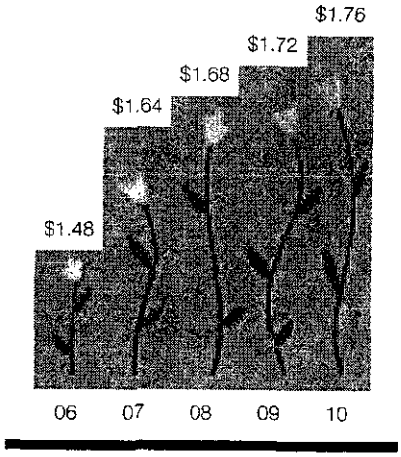
SIGNIFICANT ACHIEVEMENTS

Distribution Operations

AGL Resources achieved several significant operational and regulatory milestones in 2010. Starting with our distribution businesses, we completed rate cases at two of our six utilities: Atlanta Gas Light and Chattanooga Gas. We believe the outcome of each case allows us to continue providing safe, reliable service without overburdening our customers. At Atlanta Gas Light, our largest utility, the Georgia Public Service Commission approved a $26.7 million increase in the company's revenue requirement to support our baseline operations as well as the additional safety and compliance work we perform. The decision also allows us to offer new and improved levels of customer service through additional investment in our systems and processes. Importantly, the Commission also approved our request for an acquisition synergy-sharing mechanism that recognizes how prudent acquisitions and related savings can benefit our customers.

In addition to completing these rate cases, in 2010 AGL Resources made meaningful progress on several multi-year infrastructure projects that enhance gas supply and reliability of service. For example, the Hampton Roads Crossing pipeline that we constructed in Virginia began contributing to earnings in 2010 and is designed to provide additional revenue streams for the business going forward. We also continue to make progress with our pipeline replacement projects in Georgia and New Jersey – projects that emphasize our focus on the safety of our system, which is always of paramount importance to AGL Resources. In all of our jurisdictions we have focused on minimizing the lag between capital investment and capital recovery, ultimately providing improved earnings transparency for our shareholders.

ANNUAL DIVIDEND PER SHARE



Storage

Over the past six years, we have made significant investments in high-deliverability natural gas storage in the Gulf Coast region. These investments include our 2004 purchase of Jefferson Island Storage & Hub in Louisiana and construction of Golden Triangle Storage in Texas. Marking an important milestone in our long-term storage strategy, we successfully completed our first cavern at Golden Triangle in 2010, with the second cavern slated to come online in 2012. Despite recent weakness in the natural gas storage market, we remain committed to the long-term viability of high-deliverability storage and the importance of infrastructure projects such as Jefferson Island and Golden Triangle. We believe these assets are critical to helping ensure that Americans enjoy the benefits of clean-burning and domestically abundant natural gas for years to come.

Retail Energy Operations

Effective Jan. 1, 2010, AGL Resources increased its stake in the SouthStar Energy Services joint venture with Piedmont Natural Gas to 85 percent. In Georgia, our largest retail market, competition for customer business remains robust. By continuing to focus on customer service and leveraging its strong brand in the market, SouthStar has maintained a stable market share and continues to be the largest Georgia marketer, serving approximately 33 percent of the market.

"AGL Resources and the natural gas industry as a whole are well positioned to provide a clean, efficient and abundant source of energy to Americans."

Wholesale Services

Sequent Energy Management, AGL Resources' wholesale services business, recorded solid results during the year. While low volatility in the natural gas market provided a headwind to Sequent and much of the industry in 2010, our strategy of focusing on the fundamentals in this business helped us to navigate a challenging environment. Sequent continues to enhance its service offerings, pursue new customers in additional and existing markets, and explore new business opportunities in an effort to further bolster its success.

TRANSFORMATIVE MERGER WITH NICOR, INC.

On Dec. 7, 2010, we announced our intention to merge with Nicor, Inc., a diversified natural gas provider headquartered just outside of Chicago in Naperville, Illinois. Similar to AGL Resources, Nicor operates a leading natural gas utility as well as successful non-utility businesses. In merging with Nicor, we expect to enhance our EPS growth while maintaining a strong financial profile.

The transaction will further the diversification, scale and geographic reach of our regulated gas utility operations and provide new revenue opportunities, as well as opportunities for cost efficiencies, across both companies' unregulated businesses. Most importantly, customers will continue to experience the same high-quality, reliable and cost-effective service they enjoyed prior to the transaction. The merger is subject to a number of regulatory and other approvals, and we expect to close the transaction in the second half of 2011.

INCREASED FOCUS ON NATURAL GAS AS AN ABUNDANT DOMESTIC RESOURCE

As our nation continues to climb out of recession, AGL Resources and the natural gas industry as a whole are well positioned to provide a clean, efficient and abundant source of energy to Americans. In fact, the United States' natural gas supply outlook is better than it has been in many years. With the cost of natural gas less than one-third of the cost of foreign oil on an equivalent basis, it also is an affordable alternative that can help fuel our country's growth for decades to come. To compete successfully in the future, the natural gas industry will need to promote a wider variety of cleaner and more efficient end-use products, and commercialization of these new products will offer growth opportunities for the industry.

As a result of the affordability and abundance of natural gas, we at AGL Resources are doing our part to look for innovative ways to serve our customers' energy needs in addition to traditional pipeline delivery, which remains our primary focus. For example, in 2010 Atlanta Gas Light filed a conceptual plan with the Georgia Public Service Commission to help promote a new compressed natural gas marketplace in Georgia. Our plan is to make strategic investments throughout the state to encourage more private investment in new filling stations and new cars, trucks and buses that are fueled by CNG. These vehicles reduce

carbon emissions by 20 to 30 percent as compared to gasoline-powered vehicles, and by using domestic natural gas to displace oil in the transportation market, we improve both our energy security and national security. Also during 2010, AGL Resources partnered with Keystone Renewable Energy to form a joint venture – Renewco – for the purpose of developing landfill-based renewable gas and energy projects. While these sustainable initiatives are not the primary drivers of our business today, they demonstrate that we are leveraging our expertise in the gas industry to foster innovative solutions and new opportunities for the future.

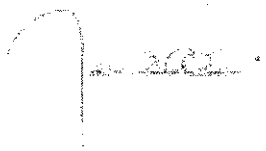
PRIORITIES FOR 2011

Clearly our top priority in 2011 will be the successful closing of the Nicor transaction and the integration of related assets into our business. While doing so, we will not lose sight of what has made us successful over the years – a relentless focus on the fundamentals in each of our businesses.

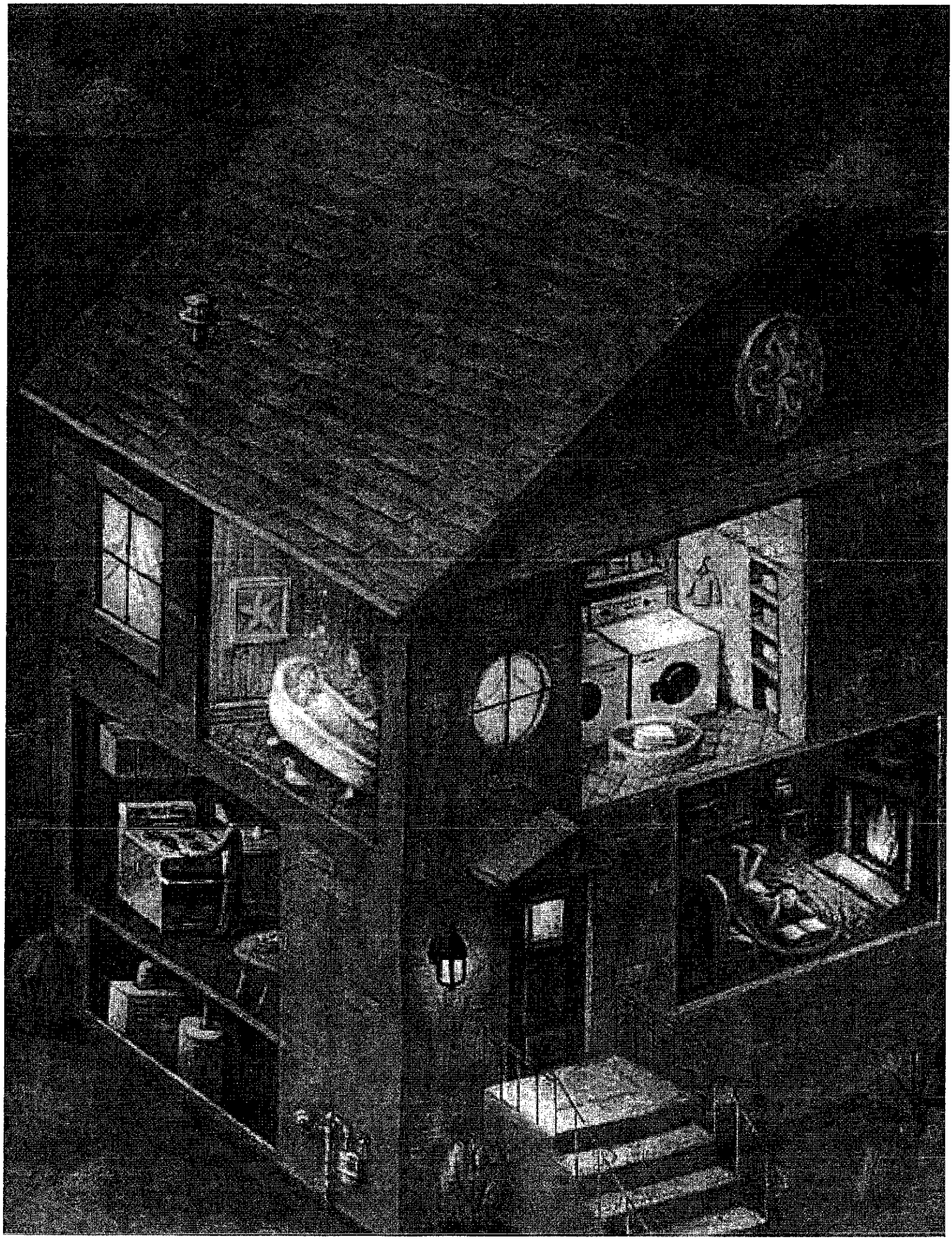
We will continue to execute on our regulatory strategy, both to achieve the necessary regulatory approvals for the Nicor transaction and to successfully resolve our Virginia Natural Gas rate case. We will invest in our utility infrastructure to ensure the highest quality service and reliability for our customers. In our non-utility businesses, we will focus on making prudent decisions that position us well for long-term success in the markets we serve, including securing additional capacity contracts for our Golden Triangle facility and completing construction of its second cavern.

Finally, in addition to focusing on initiatives specific to AGL Resources, I am honored to serve as the 2011 Chair of the American Gas Association, the industry's largest organization dedicated to communicating with federal and state regulatory and legislative bodies. I will be working with the nearly 200 strong membership of AGA to promote the inherent advantages of natural gas as a fuel. Given these advantages, utilities like ours have more opportunities than ever to tell our story and grow our business. We also will be monitoring and weighing in on key energy, environmental and tax issues that could impact our industry, businesses and investors.

I would like to thank the entire AGL Resources team, our customers and, of course, you – our shareholders – for your continued support of our initiatives. 2011 is shaping up to be an exciting year for our company and one that we look forward to sharing with each of you.



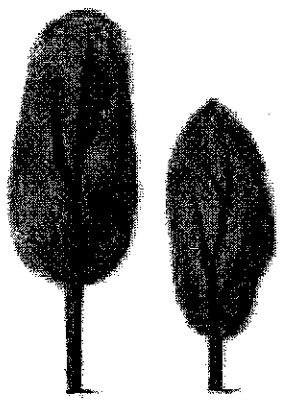
John W. Somerhalder II
Chairman, President and Chief Executive Officer
February 25, 2011



☆ STAYING TRUE TO THE ☆

Fundamentals

Americans depend on reliable energy to fuel their way of life. The balanced outcome of our rate cases in 2010 ensures our ability to operate safely and reliably, and to improve our customer service.



In October 2010, the Georgia Public Service Commission approved sufficient additional funding for Atlanta Gas Light's baseline operations as well as safety and compliance work. The funds will also allow our largest utility to improve its customer service levels. This decision marked the first increase in base rates for Atlanta Gas Light customers since 1993. The Commission also adopted a new policy that governs how cost efficiencies and savings generated by potential future utility acquisitions will benefit both customers and shareholders through an approved sharing mechanism.

In May 2010, the Tennessee Regulatory Authority approved a precedent-setting rate design for Chattanooga Gas, making Tennessee the 21st state to approve a methodology that encourages customers to pursue energy efficiency and conservation of resources while also affording the utility the ability to earn its authorized rate of return. Commonly called "decoupling," this rate design better aligns the interests of a utility and its customers by separating volume from an approved rate of return for providing service and infrastructure.

In December 2009, the New Jersey Board of Public Utilities approved a modest increase in rates for Elizabethtown Gas, the first increase in seven years, providing us with a reasonable outcome and allowing our company to continue to support growth in the state.

Our focus on executing our regulatory strategy to recover prudently incurred costs and capital investments continues in 2011. In February, Virginia Natural Gas filed a rate case with the Virginia State Corporation Commission for rate relief. The base charges that cover maintenance, safety and employee expenses for Virginia Natural Gas have remained flat since 1996.

Through effective cooperation with regulators, our customers have enjoyed a legacy of service that is safe, reliable, cost-effective and environmentally responsible. That's a fundamental commitment each of our utility companies makes to our customers.

★ INVESTING IN ★

Infrastructure

The development of new extraction technologies that allow recovery of natural gas from shale formations deep under the Earth's surface means that America has an abundant, domestic source of energy. Moving that gas to homes and businesses requires dependable storage and transmission facilities.

Domestic reserves of natural gas are estimated at 273 trillion cubic feet, an on-the-shelf inventory 50 percent larger than just 10 years ago. Total natural gas resources are estimated at over 2,000 trillion cubic feet – enough to last more than 100 years at current consumption levels. In 2010, more than 98 percent of the natural gas consumed in the United States was produced in North America.

At AGL Resources, our strategic investments in new pipelines and high-deliverability gas storage ensure that our customers have ready, reliable gas at their burner tips. In October 2009, the Georgia Public Service Commission approved an important system upgrade program called Georgia STRIDE – Strategic Infrastructure Development and Enhancement. Through this program, Atlanta Gas Light is making critical upgrades to meet our obligation to serve customers on the coldest days of the year and to provide service to growing areas of metro Atlanta. The initial three years of Georgia STRIDE, as approved by the Commission, continue through 2012. Atlanta Gas Light is also replacing aging infrastructure under the Pipeline Replacement Program, which is expected to be complete in 2013.

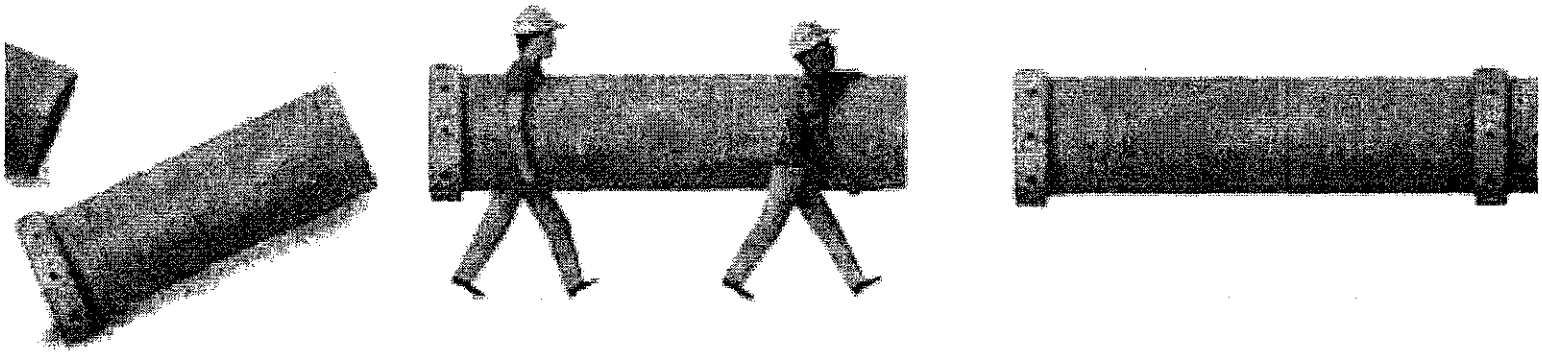
In April 2009, the New Jersey Board of Public Utilities approved a utility infrastructure enhancement rider for Elizabethtown Gas, allowing us to accelerate infrastructure projects in order to help stimulate the local economy and improve the company's natural gas distribution system.

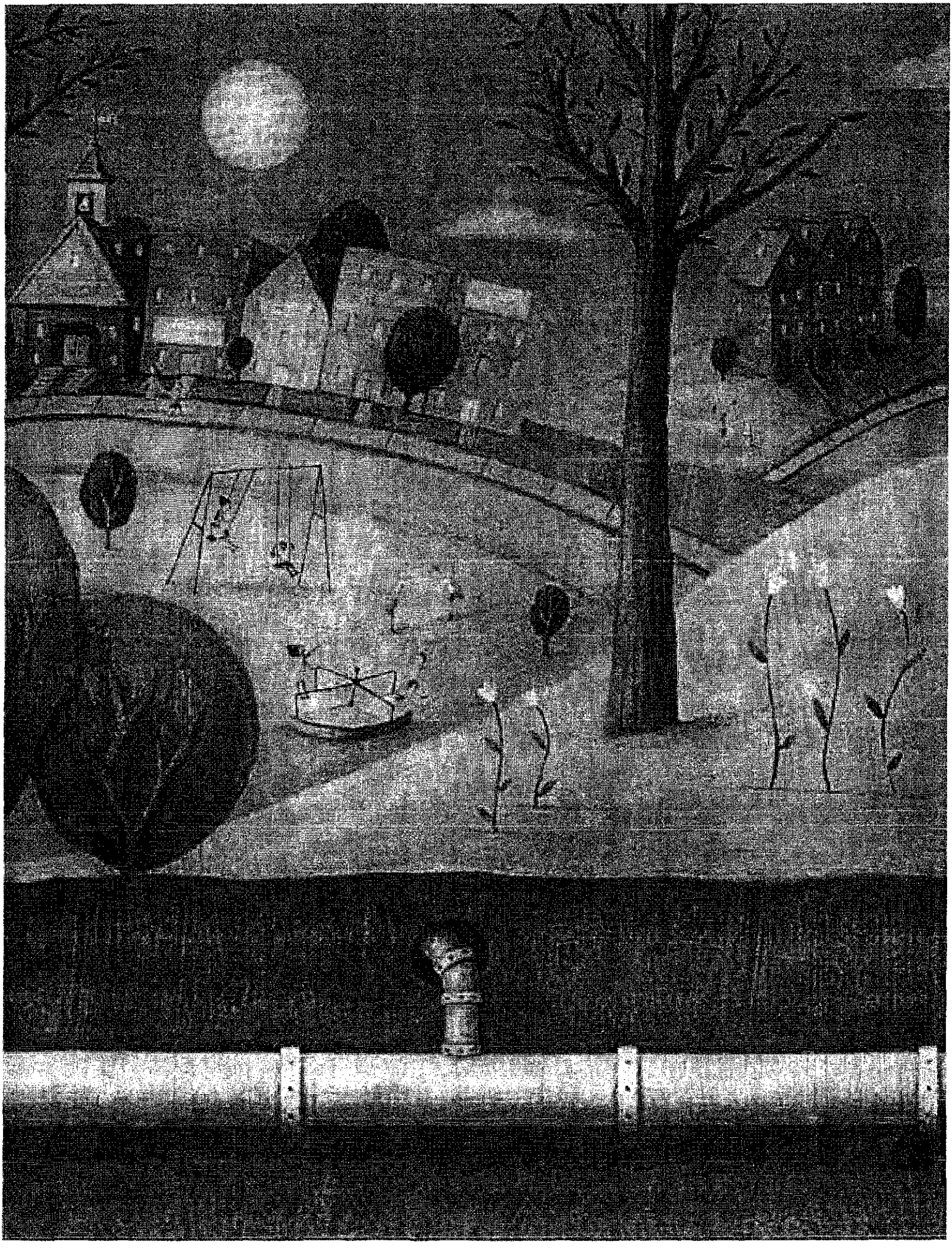
After completing construction in 2009, January 2010 marked the first full month that AGL Resources' Hampton Roads Crossing pipeline flowed gas between the northern and southern parts of the Virginia Natural Gas system, which are separated by the James River and Chesapeake Bay. Today, Hampton Roads Crossing offers more than 0.1 billion cubic feet of additional daily capacity to the region, ensuring customers have both a reliable and diverse source of natural gas supply.

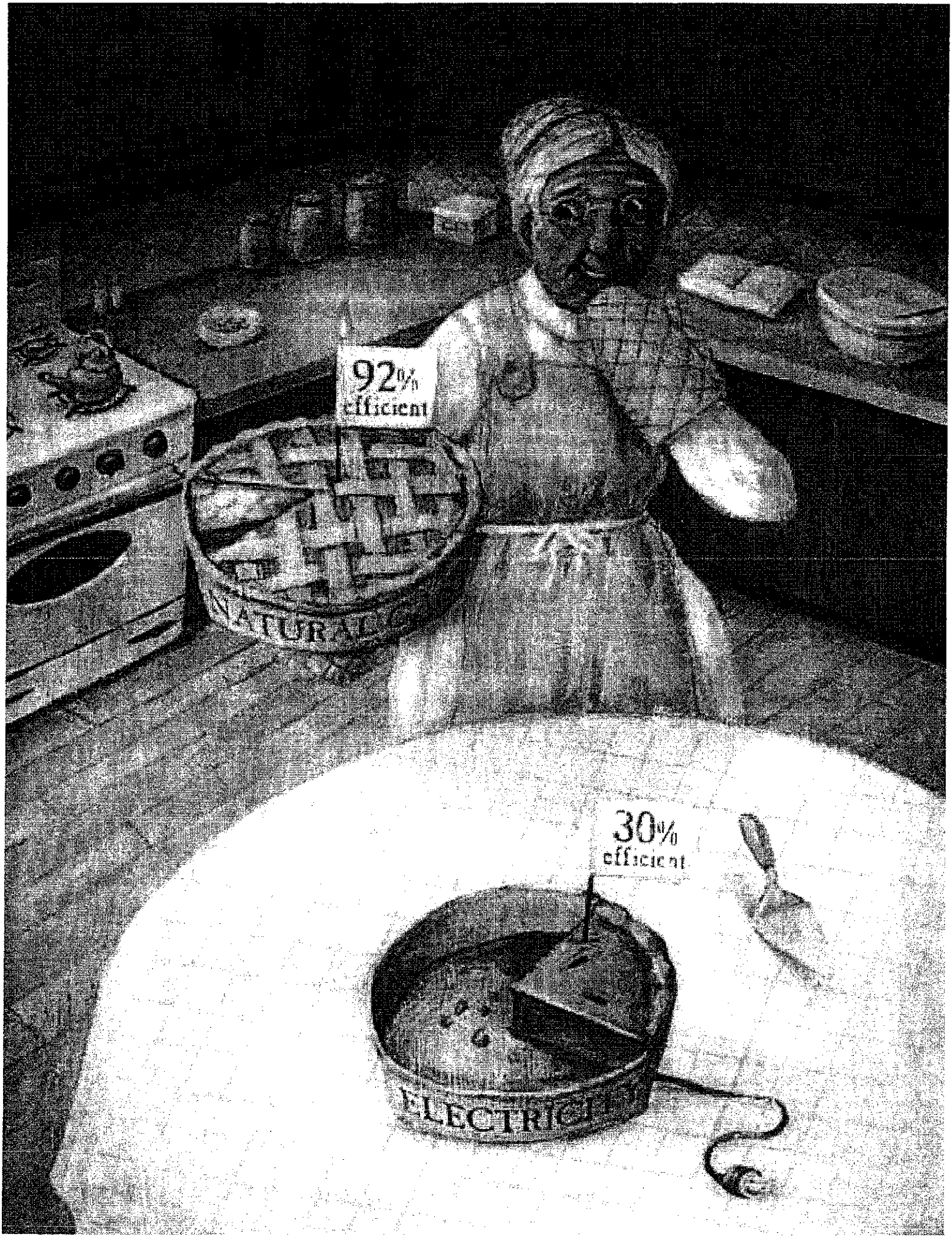
After two years of construction and cavern creation, the first natural gas storage cavern at our Golden Triangle Storage facility near Beaumont, Texas, entered initial commercial operations in September 2010. Cavern 2 is on schedule to begin service in 2012.

The caverns at Golden Triangle, along with our facility at Jefferson Island Storage & Hub in Louisiana, play a vital role in ensuring reliable supply. In the aftermath of hurricanes, for example, stored gas can be used when production or delivery is compromised. Additionally, building storage inventory levels during the low-demand summer months ensures sufficient supplies are available for the winter heating season.

Our cooperation with regulatory agencies has ensured fair and reasonable recovery of prudently incurred costs and infrastructure investments while eliminating or minimizing the time it takes to achieve full recovery of those costs through the regulatory process. These vital infrastructure projects will help our company ensure that Americans enjoy the benefits of clean-burning and domestically abundant natural gas for decades to come.






92%
efficient
NATURAL
30%
efficient
ELECTRIC

Source to Site

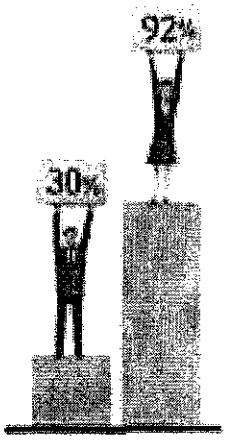
As American businesses and citizens become increasingly aware of the need for more environmentally friendly energy choices, they are discovering that highly efficient natural gas provides a cleaner, superior energy solution.

Increasingly, energy consumers – industrial, commercial and residential – are considering efficiency and environmental impact as they make vital energy decisions. Today, however, the information provided to energy users often does not accurately convey the complete picture of energy efficiency or emissions impact. That's because current standards do not account for the full-fuel cycle, which measures efficiency from initial fuel extraction all the way to customer use at the appliance.

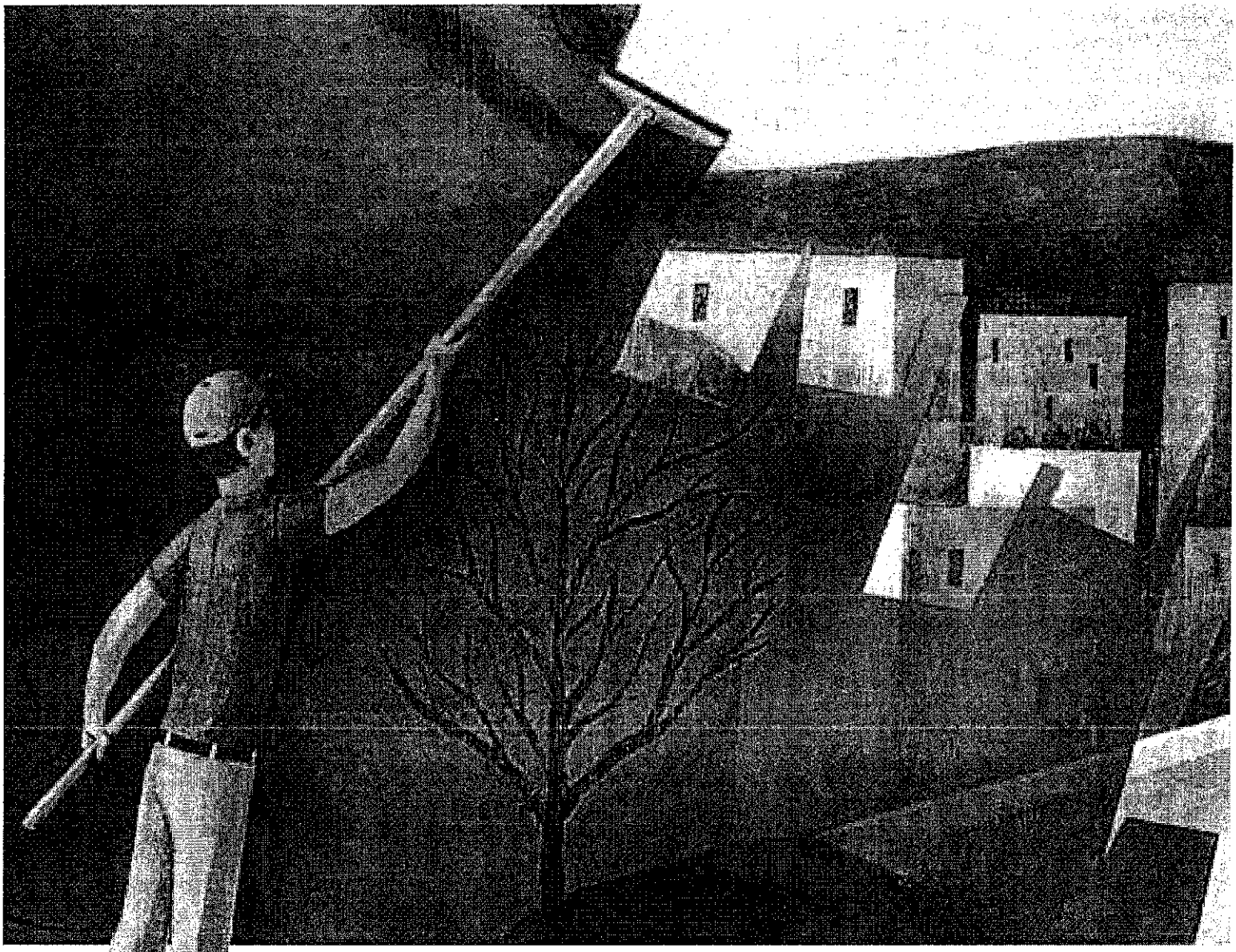
The yellow energy-efficiency labels on most appliances today do not tell the whole story for consumers weighing the choice between natural gas and electric appliances. These labels detail the energy efficiency of the appliance itself but do not account for the energy lost in the production, generation and transportation of energy to the appliance. A more accurate methodology would account for how much natural gas and electricity is wasted during the journey from their original source to an appliance. According to the U.S. Department of Energy, 92 percent of the natural gas produced at the wellhead is delivered as useful energy to appliances in homes and businesses. By contrast, only 30 percent of the electricity produced at the source is delivered as useful energy.

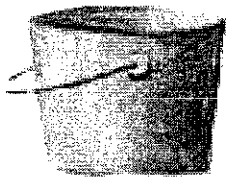
When comparing carbon emissions, the results are equally compelling: a home using natural gas appliances has a carbon footprint that is, on average, 46 percent smaller than a comparable total electric home when the full-fuel cycle is calculated.

AGL Resources – and the American Gas Association – are advocating for the U.S. Department of Energy to change the measurement to the full-fuel cycle because it more accurately reflects the efficiency and the environmental impact of natural gas and electric appliances. Equipped with better data, Americans will be empowered to make more informed energy choices for their homes and businesses. Ultimately, both people and our planet will benefit.



Electricity Natural Gas

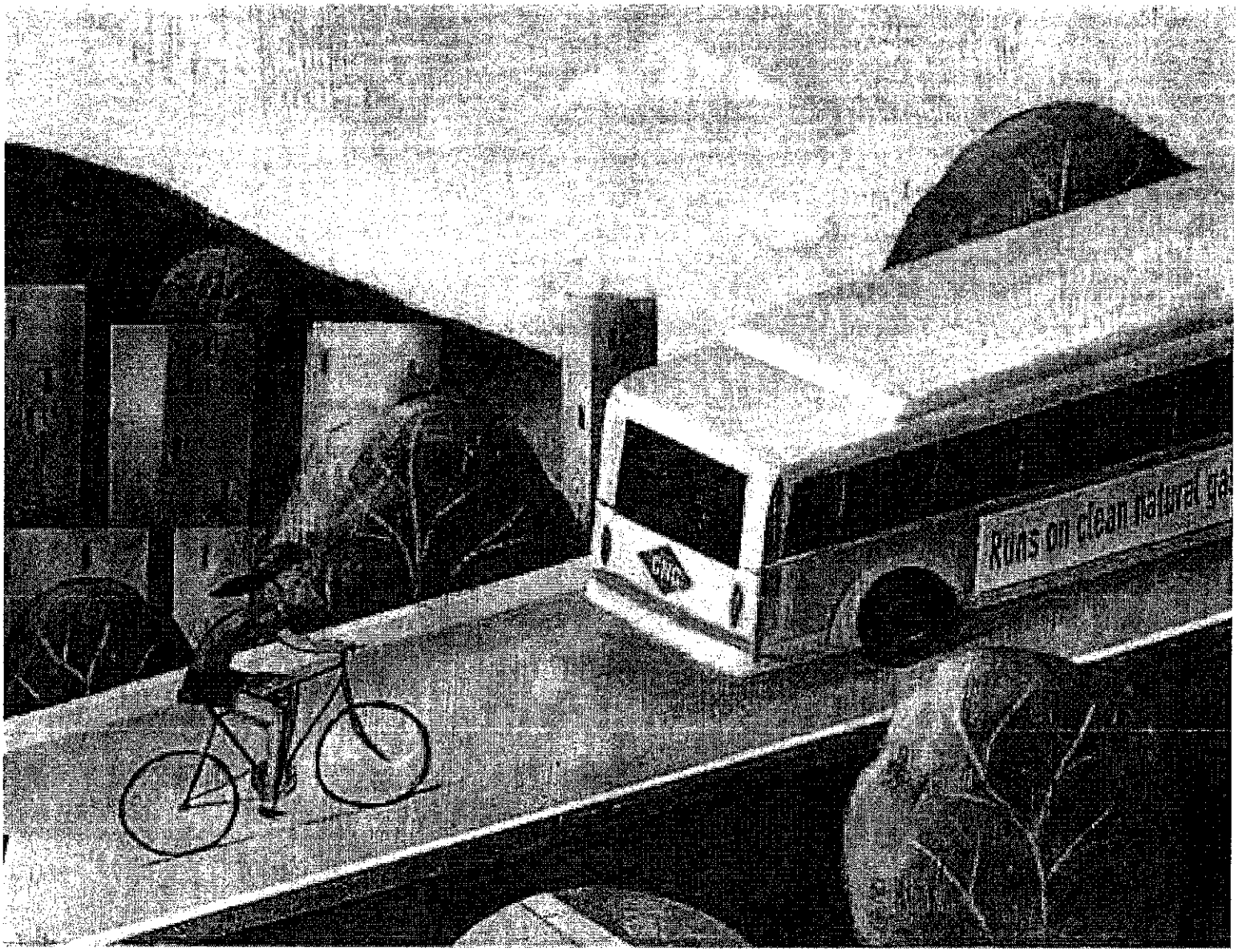




★ EXPANDING THE USE OF ★

Natural Gas

AGL Resources is focused on expanding the utilization and application of natural gas energy technologies. As a domestic energy resource, natural gas offers clear pollution reduction advantages with incomparable benefits, especially in the transportation market.



According to NGVAmerica, recent analyses estimate that natural gas vehicles produce up to 20 to 30 percent less greenhouse gas emissions than comparable diesel- and gasoline-fueled vehicles. Natural gas also offers significant cost advantages over other fuels and reduces the nation's reliance on foreign oil.

More than 12 million natural gas vehicles are on the road worldwide, but only about 100,000 of those are in the United States. At AGL Resources, we believe the time is right to invest in natural gas-fueled transportation. In September 2010, Atlanta Gas Light filed a conceptual plan with the Georgia Public Service Commission to help promote a new compressed natural gas marketplace in Georgia. By making strategic investments throughout the state, our plan is to encourage more private investment in new compressed natural gas filling stations and new cars, trucks and buses. Investing in environmentally friendly natural gas transportation will provide job growth and create a greener, more efficient economy while improving our energy security by displacing oil with domestic natural gas.

In 2010, AGL Resources added to its own fleet of natural gas vehicles. In addition to its dedicated CNG Honda Civics and bi-fuel vans and trucks, the company added nine bi-fuel Ford vehicles that can operate on either natural gas or gasoline to its fleet. Over time, the company plans to continue replacing older gasoline-powered fleet vehicles with ones that run on natural gas.

Transportation is just one opportunity to expand the use of natural gas. Our industry is collaborating and making commitments to support a variety of new technologies, including natural gas heat pumps and combined heat-and-power systems as well as natural gas vehicles. At the same time, government-supported research and development will serve as a springboard for new products and applications, further advancing the value and benefits of natural gas for all Americans.

✯ AT A GLANCE ✯

We are an energy services holding company, headquartered in Atlanta.

Distributions Operations

Atlanta Gas Light provides natural gas delivery service to approximately 1.5 million residential, commercial and industrial end-use customers throughout Georgia.

Chattanooga Gas provides natural gas service to approximately 62,000 residential, commercial and industrial customers in Hamilton County and Bradley County, Tennessee.

Elizabethtown Gas provides natural gas service to approximately 274,000 residential, commercial and industrial customers in northwestern and east central New Jersey.

Elkton Gas provides natural gas service to approximately 6,000 residential, commercial and industrial customers in northeastern Maryland.

Florida City Gas provides natural gas service to approximately 103,000 residential, commercial and industrial customers in southeastern and east central Florida.

Virginia Natural Gas provides natural gas service to approximately 275,000 residential, commercial and industrial customers in southeastern Virginia.

Retail Energy Operations

SouthStar Energy Services is a joint venture operating in Georgia under the trade name Georgia Natural Gas. The business supplies natural gas to approximately 496,000 retail and commercial customers in Georgia and approximately 77,000 end use customers in Ohio and Florida.

Wholesale Services

Sequent Energy Management, our Houston-based subsidiary, provides customers throughout the United States and in Canada with the ability to optimize their natural gas asset portfolio and increase cost-effectiveness from wellhead to burner tip. Services include natural gas asset management, producer and storage services, full-requirements supply and peaking needs.

Energy Investments

Jefferson Island Storage & Hub operates a high-deliverability natural gas storage facility in Louisiana. The facility consists of two salt-dome storage caverns with 10 billion cubic feet of total capacity and approximately 7.5 billion cubic feet of working gas capacity.

Golden Triangle Storage is a new salt-dome storage facility in Texas which, when construction is complete, will consist of two underground caverns that will hold approximately 18 billion cubic feet of total capacity and approximately 12 billion cubic feet of working gas capacity. The first cavern with 6 billion cubic feet of working gas capacity began commercial service in September 2010. The second cavern is expected to be in service in 2012.

✯ BOARD OF DIRECTORS ✯

Sandra N. Bane [1,2]
Retired partner, KPMG LLP
Pasadena, CA
Director since 2008

Thomas D. Bell, Jr. [2,4]
Chairman
SecurAmerica LLC
Atlanta, GA
Director since 2004

Charles R. Crisp [2,4]
Former President,
Chief Executive Officer
Coral Energy, LLC,
a subsidiary of Shell Oil Company
Houston, TX
Director since 2003

Arthur E. Johnson [2,3**,4]
Former Senior Vice President,
Corporate Strategic Development
Lockheed Martin Corporation
Reston, VA
Director since 2002

Wyck A. Knox, Jr. [1,5]
Former partner and Chairman
of the Executive Committee
Kilpatrick Stockton, LLP
Augusta, GA
Director since 1998

Dennis M. Love [1,3,5*]
President and Chief Executive Officer
Printpack, Inc.
Atlanta, GA
Director since 1999

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

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

James A. Rubright [2,3,4*]
Chairman and Chief Executive Officer
Rock-Tenn Company
Norcross, GA
Director since 2001

John W. Somerhalder II [3,4]
Chairman, President and
Chief Executive Officer
AGL Resources, Inc.
Atlanta, GA
Director since 2006

Bettina M. Whyte [2*,3,4]
Retired Chairman, The Advisory
Board of Bridge Associates, LLC
Senior Adviser, Alvarez & Marsal
Jackson, WY
Director since 2004

Henry C. Wolf [1*,3,5]
Former Vice Chairman and
Chief Financial Officer
Norfolk Southern Corporation
Norfolk, VA
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
** Lead Director

✯ EXECUTIVE OFFICERS ✯

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

Ralph Cleveland
Executive Vice President
Engineering and Operations

Andrew W. Evans
Executive Vice President and
Chief Financial Officer

Henry P. Linginfelter
Executive Vice President
Utility Operations

Melanie M. Platt
Senior Vice President
Human Resources and
Marketing Communications

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

Pete I. Tumminello
President
Sequent Energy Management, L.P.

★ Financials ★

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, 2010
OR

☐ Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from to

Commission File Number 1-14174

AGL RESOURCES INC.

(Exact name of registrant as specified in its charter)

Georgia	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 voting and non-voting common equity held by non affiliates of the registrant, computed by reference to the price at which the registrant's common stock was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter, was $2,792,228,461.

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

Documents Incorporated by reference:

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

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GLOSSARY OF KEY TERMS

AGL Capital AGL Capital Corporation

AGL Networks AGL Networks, LLC

Atlanta Gas Light Atlanta Gas Light Company

Bcf Billion cubic feet

Bridge Facility $1.05 billion credit agreement entered into by AGL Capital to help finance a portion of the proposed merger with Nicor

Chattanooga Gas Chattanooga Gas Company

Credit Facility $1 billion credit agreement entered into by AGL Capital

EBIT Earnings before interest and taxes, a non-GAAP measure that includes operating income and other income and excludes financing costs, including interest and debt and income tax expense each of which we evaluate on a consolidated level; as an indicator of our operating performance, EBIT should not be considered an alternative to, or more meaningful than, earnings before income taxes, or net income attributable to AGL Resources Inc. as determined in accordance with GAAP

ERC Environmental remediation costs associated with our distribution operations segment which are generally recoverable through rate mechanisms

FASB Financial Accounting Standards Board

FERC Federal Energy Regulatory Commission

Fitch Fitch Ratings

Florida Commission Florida Public Service Commission, the state regulatory agency for Florida City Gas

GAAP Accounting principles generally accepted in the United States of America

Georgia Commission Georgia Public Service Commission, the state regulatory agency for Atlanta Gas Light

GNG Georgia Natural Gas, the name under which SouthStar does business in Georgia

Golden Triangle Storage Golden Triangle Storage, Inc.

Hampton Roads Virginia Natural Gas' pipeline project which connects its northern and southern pipelines

Heating Degree Days A measure of the effects of weather on our businesses, calculated when the average daily temperatures are less than 65 degrees Fahrenheit

Heating Season The period from November to March when natural gas usage and operating revenues are generally higher because more customers are connected to our distribution systems when weather is colder

Henry Hub A major interconnection point of natural gas pipelines in Erath, Louisiana where NYMEX natural gas future contracts are priced

Jefferson Island Jefferson Island Storage & Hub, LLC

LNG Liquefied natural gas

LOCOM Lower of weighted average cost or current market price

Magnolia Magnolia Enterprise Holdings, Inc.

Marketers Marketers selling retail natural gas in Georgia and certificated by the Georgia Commission

Mcf Million cubic feet

MGP Manufactured gas plant

Moody's Moody's Investors Service

New Jersey BPU New Jersey Board of Public Utilities, the state regulatory agency for Elizabethtown Gas

Nicor Nicor Inc., an Illinois corporation

NUI NUI Corporation – an acquisition completed in November 2004

NYMEX New York Mercantile Exchange, Inc.

OCI Other comprehensive income

Operating margin A non-GAAP measure of income, calculated as operating revenues minus cost of gas, that excludes operation and maintenance expense, depreciation and amortization, taxes other than income taxes, and the gain or loss on the sale of our assets; these items are included in our calculation of operating income as reflected in our Consolidated Statements of Income. Operating margin should not be considered an alternative to, or more meaningful than, operating income as determined in accordance with GAAP

OTC Over-the-counter

Piedmont Piedmont Natural Gas Company, Inc.

Pivotal Utility Pivotal Utility Holdings, Inc., doing business as Elizabethtown Gas, Elkton Gas and Florida City Gas

PP&E Property, plant and equipment

S&P Standard & Poor's Ratings Services

SEC Securities and Exchange Commission

Sequent Sequent Energy Management, L.P.

SouthStar SouthStar Energy Services LLC

STRIDE Atlanta Gas Light's Strategic Infrastructure Development and Enhancement program

Tennessee Authority Tennessee Regulatory Authority, the state regulatory agency for Chattanooga Gas

Term Loan Facility $300 million credit agreement entered into by AGL Capital to repay the $300 million senior notes due in 2011

VaR Value at risk is defined as the maximum potential loss in portfolio value over a specified time period that is not expected to be exceeded within a given degree of probability

Virginia Natural Gas Virginia Natural Gas, Inc.

Virginia Commission Virginia State Corporation Commission, the state regulatory agency for Virginia Natural Gas

WACOG Weighted average cost of gas

WNA Weather normalization adjustment

Forward-Looking Statements

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

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

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

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

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

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

Item 1. Business

Nature of Our Business

Unless the context requires otherwise, references to "we," "us," "our," the "company" and "AGL Resources" are intended to mean consolidated AGL Resources Inc. and its subsidiaries. We are an energy services holding company whose principal business is the distribution of natural gas in six states - Florida, Georgia, Maryland, New Jersey, Tennessee and Virginia. Our six utilities serve approximately 2.3 million end-use customers.

We are also involved in several related and complementary businesses, including retail natural gas marketing to end-use customers in Georgia, Ohio and Florida; natural gas asset management and related logistics activities for each of our utilities as well as for non-affiliated companies; natural gas storage arbitrage and related activities; and the development and operation of high-deliverability natural gas storage assets. We manage these businesses through four operating segments — distribution operations, retail energy operations, wholesale services and energy investments — and a non-operating corporate segment.

Proposed Merger with Nicor

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

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

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

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

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

Distribution Operations

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

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

Utility Regulation and Rate Design

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

For our largest utility, Atlanta Gas Light, the natural gas market was deregulated in 1997. Accordingly, Marketers, rather than a traditional utility, sell natural gas to end-use customers in Georgia and handle customer billing functions. The Marketers file their rates monthly with the Georgia Commission. As a result of operating in a deregulated environment, Atlanta Gas Light's role includes:

- distributing natural gas for Marketers
- constructing, operating and maintaining the gas system infrastructure, including responding to customer service calls and leaks
- reading meters and maintaining underlying customer premise information for Marketers
- planning and contracting for capacity on interstate transportation and storage systems

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

With the exception of Atlanta Gas Light, the earnings of our regulated utilities can be affected by customer consumption patterns that are a function of weather conditions and price levels for natural gas. Specifically, customer demand substantially increases during the Heating Season when natural gas is used for heating purposes. Various mechanisms such as weather normalization mechanisms exist at most of our utilities that limit our exposure to weather changes within typical ranges in all of our jurisdictions.

All of our utilities, excluding Atlanta Gas Light, are authorized to use natural gas cost recovery mechanisms that allow them to adjust their rates to reflect changes in the wholesale cost of natural gas and to ensure they recover 100% of the costs incurred in purchasing gas for their customers. Since Atlanta Gas Light does not sell natural gas directly to its end-use customers, it does not need or utilize a natural gas cost recovery mechanism.

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

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

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

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

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

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

The following table provides regulatory information for our largest utilities.

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

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

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

(3) Estimated based on 13-month average.

(4) Involves frozen rates.

(5) Involves regulatory mechanisms that allow us to recover our costs in the event of unseasonal weather, but are not direct offsets to the potential impacts of weather and customer consumption on earnings. These mechanisms are designed to help stabilize operating results by increasing base rate amounts charged to customers when weather is warmer than normal and decreasing amounts charged when weather is colder than normal.

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

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

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

Environmental Remediation Costs

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. The following table provides more information on the costs related to remediation of our former operating sites.

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

We report these estimates on an undiscounted basis. As we continue to conduct the actual remediation and enter into cleanup contracts, we are increasingly able to provide conventional engineering estimates of the likely costs of many elements of the remediation program. These estimates contain various engineering uncertainties, and we regularly attempt to refine and update these engineering estimates. We primarily recover these costs through rate riders.

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

Competition and Customer Demand

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

Competition for space heating and general household and small commercial energy needs generally occurs at the initial installation phase when the customer or builder makes decisions as to which types of equipment to install. Customers generally continue to use the chosen energy source for the life of the equipment. Customer demand for natural gas could be affected by numerous factors, including:

- changes in the availability or price of natural gas and other forms of energy
- general economic conditions
- energy conservation
- legislation and regulations
- the capability to convert from natural gas to alternative fuels
- weather
- new commercial construction and
- new housing starts.

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

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

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

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

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

Capital Projects

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

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

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

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

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

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

Collective Bargaining Agreements

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

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

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

Retail Energy Operations

Our retail energy operations segment consists of SouthStar, a joint venture currently owned 85% by our subsidiary, Georgia Natural Gas Company, and 15% by Piedmont. SouthStar markets natural gas and related services under the trade name Georgia Natural Gas to retail customers on an unregulated basis, primarily in Georgia. SouthStar also serves retail customers in Ohio and Florida and markets natural gas to larger commercial and industrial customers in Alabama, Tennessee, North Carolina, South Carolina, Florida and Georgia.

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

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

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

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

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

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

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

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

The second way SouthStar generates revenues is through the collection of monthly service fees and customer late payment fees. SouthStar evaluates the combination of these two retail price components to ensure such pricing is structured to cover related retail customer costs, such as bad debt expense, customer service and billing, and lost and unaccounted-for gas, and to provide a reasonable profit, as well as being competitive to attract new customers and maintain market share.

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

Wholesale Services

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

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

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

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

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

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

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

Sequent has entered into asset management agreements with our affiliated utilities that include profit sharing mechanisms and fixed fee payments that require Sequent to make aggregate annual minimum payments of $10 million in

2011. These agreements are scheduled to expire over the next three years. The following table provides payments made under these agreements during the last three years.

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

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

As Sequent executes transactions to secure transportation capacity, it often enters into forward financial contracts to hedge its positions and lock-in a margin on future transportation activities. The hedging instruments are derivatives, and Sequent reflects changes in the derivatives' fair value in its reported operating results in the period of change, which can be in periods prior to actual utilization of the transportation capacity.

Producer Services Sequent's producer services business primarily focuses on aggregating natural gas supply from various small and medium-sized producers located throughout the natural gas production areas of the United States. Sequent provides producers with certain logistical and risk management services that offer them attractive options to move their supply into the pipeline grid.

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

Energy Marketing Activities Sequent purchases natural gas for storage when the current market price it pays plus the cost for transportation and storage is less than the market price it anticipates it could receive in the future. Sequent attempts to mitigate substantially all of the commodity price risk associated with its storage portfolio and uses derivative instruments to reduce the risk associated with future changes in the price of natural gas. Sequent sells NYMEX futures contracts or OTC derivatives in forward months to substantially lock in the operating revenue it will ultimately realize when the stored gas is actually sold.

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

Sequent accounts for natural gas stored in inventory differently than the derivatives Sequent uses to mitigate the commodity price risk associated with its storage portfolio. The natural gas that Sequent purchases and injects into storage is accounted for at the lower of average cost or current market value. The derivatives that Sequent uses to mitigate commodity price risk are accounted for at fair value and marked to market each period. This difference in accounting treatment can result in volatility in Sequent's reported results, even though the expected operating revenue is essentially unchanged from the date the transactions were initiated. These accounting differences also affect the comparability of Sequent's period-over-period results, since changes in forward NYMEX prices do not increase and decrease on a consistent basis from year to year.

Sequent's expected natural gas withdrawals from physical salt-dome and reservoir storage are presented in the following table along with the operating revenues expected at the time of withdrawal. Sequent's expected operating revenues are net of the estimated impact of profit sharing under our asset management

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

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

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

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

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

Sequent enters into forward NYMEX contracts to hedge the natural gas price risk associated with its park and loan transactions. While the hedging instruments mitigate the price risk associated with the delivery and receipt of natural gas, they can also result in volatility in Sequent's reported results during the period before the initial delivery or receipt of natural gas. During this period, if the forward NYMEX prices in the months of delivery and receipt do not change in equal amounts, Sequent will report a net unrealized gain or loss on the hedges. Once gas is delivered under the park and loan transaction, earnings volatility is essentially eliminated since the park and loan transaction contains an embedded derivative, which is also marked to market and would substantially offset subsequent changes in value of the forward NYMEX contracts used to hedge the park and loan transaction.

Energy Investments

Our energy investments segment includes a number of businesses that are related and complementary to our primary business. The most significant of these businesses is our natural gas storage business, which develops, acquires and operates high-deliverability salt-dome caverns and other storage assets in the Gulf Coast region of the United States. While this business can also generate additional revenue during times of peak market demand for natural gas storage services, the majority of our natural gas storage facilities are covered under a portfolio of short, medium and long-term contracts at a fixed market rate. We generally have had approximately 90% to 95% of Jefferson Island's working natural gas capacity under firm subscription. As Golden Triangle Storage begins full commercial operations during the first quarter of 2011, it will market its remaining available working natural gas capacity taking into consideration the prevailing market conditions in establishing rates and tenor of capacity contracts.

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

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

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

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

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

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

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

Corporate

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

AGL Capital, our wholly-owned finance subsidiary, provides for our ongoing financing needs through a commercial paper program, the issuance of various debt and hybrid securities, and other financing arrangements. Our corporate segment also includes intercompany eliminations for transactions between our operating business segments. Our EBIT results include the impact of these allocations to the various operating segments.

Employees

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

Additional Information

For additional information on our segments, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Results of Operations" and "Note 12, Segment Information," set forth in Item 8, "Financial Statements and Supplementary Data."

Available Information

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

AGL Resources Inc.
Investor Relations - Dept. 1071
P.O. Box 4569
Atlanta, GA 30302-4569
404-584-4000

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

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

Item 1A. Risk Factors

Risks Related to Our Business

Risks related to the regulation of our businesses could affect the rates we are able to charge, our costs and our profitability. Our businesses are subject to regulation by federal, state and local regulatory authorities. In particular, at the federal level our businesses are regulated by the FERC. At the state level, our businesses are regulated by the Georgia, Tennessee, New Jersey, Florida, Virginia and Maryland regulatory authorities.

These authorities regulate many aspects of our operations, including construction and maintenance of facilities, operations, safety, rates that we charge customers, rates of return, the authorized cost of capital, recovery of costs associated with our regulatory infrastructure projects, including our pipeline replacement programs, and environmental remediation activities, relationships with our affiliates, and carrying costs we charge Marketers selling retail natural gas in Georgia for gas held in storage for their customer accounts. Our ability to obtain rate increases and rate supplements to maintain our current rates of return and recover regulatory assets and liabilities recorded in accordance with authoritative guidance related to regulated operations depends on regulatory discretion, and there can be no assurance that we will be able to obtain rate increases or rate supplements or continue receiving our currently authorized rates of return including the recovery of our regulatory assets and liabilities.

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

We could incur significant compliance costs if we must adjust to new regulations. In addition, as the regulatory environment for our industry increases in complexity, the risk of inadvertent noncompliance could also increase. If we fail to comply with applicable regulations, whether existing or new ones, we could be subject to fines, penalties or other enforcement action by the authorities that regulate our operations, or otherwise be subject to material costs and liabilities. This may require increased use of working capital for Sequent.

In 1997, Georgia enacted legislation allowing deregulation of gas distribution operations. To date, Georgia is the only state in the nation that has fully deregulated gas distribution operations, which ultimately resulted in Atlanta Gas Light exiting the retail natural gas sales business while retaining its gas distribution operations. Marketers, including our majority-owned subsidiary, SouthStar, then assumed the retail gas sales responsibility at deregulated prices. The deregulation process required Atlanta Gas Light to completely reorganize its operations and personnel at significant expense. It is possible that the legislature could reverse or amend portions of the deregulation process.

Our business is subject to environmental regulation in all jurisdictions in which we operate, and our costs to comply are significant. Any changes in existing environmental regulation could affect our results of operations and financial condition. Our operations and properties are subject to extensive environmental regulation pursuant to a variety of federal, state and municipal laws and regulations. Such environmental legislation imposes, among other things, restrictions, liabilities and obligations in connection with storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances into the environment. Environmental legislation also requires that our facilities, sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Our current costs to comply with these laws and regulations are significant to our results of operations and financial condition. Failure to comply with these laws and regulations and failure to obtain any required permits and licenses may expose us to fines, penalties or interruptions in our operations that could be material to our results of operations.

In addition, claims against us under environmental laws and regulations could result in material costs and liabilities. Existing environmental regulations could also be revised or reinterpreted, new laws and regulations could be adopted or become applicable to us or our facilities, and future changes in environmental laws and regulations could occur. With the trend toward stricter standards, greater regulation, more extensive permit requirements and an increase in the number and types of assets operated by us subject to environmental regulation, our environmental expenditures could increase in the future, particularly if those costs are not fully recoverable from our customers. Additionally, the discovery of presently unknown environmental conditions could give rise to expenditures and liabilities, including fines or penalties, which could have a material adverse effect on our business, results of operations or financial condition.

Our infrastructure improvement and customer growth may be restricted by the capital-intensive nature of our business. We must construct additions to our natural gas distribution system to continue the expansion of our customer base and improve system reliability, especially during peak usage. We may also need to construct expansions of our existing natural gas storage facilities or develop and construct new natural gas storage facilities. The cost of this construction may be

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

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

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

Presently there are no federally mandated greenhouse gas reduction requirements in the United States. However, there are a number of legislative and regulatory proposals to address greenhouse gas emissions, which are in various phases of discussion or implementation. The outcome of federal and state actions to address global climate change could result in a variety of regulatory programs including potential new regulations, additional charges to fund energy efficiency activities, or other regulatory actions. These actions could:

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

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

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

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

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

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

The natural gas business is highly competitive, increasingly complex, and we are facing increasing competition from other companies that supply energy, including electric companies, oil and propane providers and, in some cases, energy marketing and trading companies. In particular, the success of our investment in SouthStar is affected by the competition SouthStar faces from other energy marketers providing retail natural gas services in the Southeast. Natural gas competes with other forms of energy. The primary competitive factor is price. Changes in the price or availability of natural gas relative to other forms of energy and the ability of end-users to convert to alternative fuels affect the demand for natural gas. In the case of commercial, industrial and agricultural customers, adverse economic conditions, including higher gas costs, could also cause these customers to bypass or disconnect from our systems in favor of special competitive contracts with lower per-unit costs.

Our wholesale services segment competes with national and regional full-service energy providers, energy merchants and producers and pipelines for sales based on our ability to aggregate competitively priced commodities with transportation and storage capacity. Some of our competitors are larger and better capitalized than we are and have more national and global exposure than we do. The consolidation of this industry and the pricing to gain market share may affect our operating margin. We expect this trend to continue in the near term, and the increasing competition for asset management deals could result in downward pressure on the volume of transactions and the related operating margin available in this portion of Sequent's business.

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

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

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

We have accounts receivable collection risk in Georgia due to a concentration of credit risk related to the provision of natural gas services to Marketers. At December 31, 2010, Atlanta Gas Light had eleven certificated and active Marketers in Georgia, four of which (based on customer count and including SouthStar) accounted for approximately 31% of our consolidated operating margin for 2010. As a result, Atlanta Gas Light depends on a concentrated number of customers for revenues. The provisions of Atlanta Gas Light's tariff allow it to obtain security support in an amount equal to no less than two times a Marketer's highest month's estimated bill in the form of cash deposits, letters of credit, surety bonds or guaranties. The failure of these Marketers to pay Atlanta Gas Light could adversely affect Atlanta Gas Light's business and results of operations and expose it to difficulties in collecting Atlanta Gas Light's accounts receivable. AGL Resources provides a guarantee to Atlanta Gas Light as security support for SouthStar. Additionally, SouthStar markets directly to end-use customers and has periodically experienced credit losses as a result of severe cold weather or high prices for natural gas that increase customers' bills and, consequently, impair customers' ability to pay.

Sequent often extends credit to its counterparties. Despite performing credit analyses prior to extending credit and seeking to effectuate netting agreements, Sequent is exposed to the risk that it may not be able to collect amounts owed to it. If the counterparty to such a transaction fails to perform and any collateral Sequent has secured is inadequate, Sequent could experience material financial losses. Further, Sequent has a concentration of credit risk, which could subject a significant portion of its credit exposure to collection risks. Approximately 56% of Sequent's credit exposure, excluding $61 million of customer deposits, is concentrated in its top 20 counterparties. Most of this concentration is with counterparties that are either load-serving utilities or end-use customers that have supplied some level of credit support. Default by any of these counterparties in their obligations to pay amounts due Sequent could result in credit losses that would negatively impact our wholesale services segment.

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

Sequent currently manages the storage and transportation assets of our affiliates Atlanta Gas Light, Chattanooga Gas, Elizabethtown Gas, Elkton Gas, Florida City Gas, and Virginia Natural Gas and shares profits it earns from the management of those assets with those customers and their respective customers, except at Elkton Gas where Sequent is assessed annual fixed-fees payable in monthly installments. Entry into and renewal of these agreements are subject to regulatory approval. The asset management agreement for Elizabethtown Gas expires in March 2011 and we are currently working with the New Jersey BPU to extend this agreement for an additional three years. The agreements for Atlanta Gas Light and Virginia Natural Gas are subject to renewal in March 2012. Additionally, the agreement with Florida City Gas expires in March 2013 and the agreement with Chattanooga Gas expires in March 2014.

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

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

The commodity, storage and transportation portfolios at Sequent and the commodity and storage portfolios at SouthStar consist of contracts to buy and sell natural gas commodities, including contracts that are settled by the delivery of the commodity or cash. If the values of these contracts change in a direction or manner that we do not anticipate, we could experience financial losses from our trading activities. Based on a 95% confidence interval and employing a 1-day holding period for all positions, Sequent's and SouthStar's portfolio of positions as of December 31, 2010 had a 1-day holding period VaR of $1.6 million and less than $0.1 million, respectively.

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

Although Sequent enters into various contracts to hedge the value of our energy assets and operations, the timing of the recognition of profits or losses on the hedges does not always correspond to the profits or losses on the item being hedged. The difference in accounting can result in volatility in Sequent's reported results, even though the expected operating margin is essentially unchanged from the date the transactions were initiated.

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

We have a WNA mechanism for Elizabethtown Gas and Chattanooga Gas that partially offsets the impact of unusually cold or warm weather on residential and commercial customer billings and our operating margin. At Elizabethtown Gas we could be required to return a portion of any WNA surcharge to its customers if Elizabethtown Gas' return on equity exceeds its authorized return on equity of 10.3%.

Additionally, Virginia Natural Gas has a WNA mechanism for its residential customers that partially offsets the impacts of unusually cold or warm weather. In September 2007, the Virginia Commission approved Virginia Natural Gas' application for an Experimental Weather Normalization Adjustment Rider (the Rider) for its commercial customers. The Rider applied to the 2007 and 2008 Heating Seasons. In September 2009 the Rider was extended to September 2011.

These WNA regulatory mechanisms are most effective in a reasonable temperature range relative to normal weather using historical averages. The protection afforded by the WNA depends on continued regulatory approval. The loss of this continued regulatory approval could make us more susceptible to weather-related earnings fluctuations.

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

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

Our profitability may decline if the counterparties to **Sequent's asset management transactions fail to perform in accordance with Sequent's agreements.**
Sequent focuses on capturing the value from idle or underutilized energy assets, typically by executing transactions that balance the needs of various markets and time horizons. Sequent is exposed to the risk that counterparties to our transactions will not perform their obligations. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative hedging arrangements, honor the underlying commitment at then-current market prices or return a significant portion of the consideration received for gas. In such events, we may incur additional losses to the extent of amounts, if any, already paid to or received from counterparties.

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

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

In addition, we are associated with former sites in New Jersey and North Carolina. Material cleanups of these sites have not been completed nor are precise estimates available for future cleanup costs and therefore considerable variability remains in future cost estimates. For the New Jersey sites, cleanup cost estimates range from $75 million to $138 million. Costs have been estimated for one site in North Carolina and range from $11 million to $16 million.

Inflation and increased gas costs could adversely impact our ability to control operating expenses, increase our level of indebtedness and adversely impact our customer base. Inflation has caused increases in certain operating expenses that have required us to replace assets at higher costs. We attempt to control costs in part through implementation of best practices and business process improvements, many of which are facilitated through investments in information systems and technology. We have a process in place to continually review the adequacy of our utility gas rates in relation to the increasing cost of providing service and the inherent regulatory lag in adjusting those gas rates. Historically, we have been able to control operating expenses and investments within the amounts authorized to be collected in rates, and we intend to continue to do so. However, any inability by us to control our expenses in a reasonable manner would adversely influence our future results.

Rapid increases in the price of purchased gas cause us to experience a significant increase in short-term debt because we must pay suppliers for gas when it is purchased, which can be significantly in advance of when these costs may be recovered through the collection of monthly customer bills for gas delivered. Increases in purchased gas costs also slow our utility collection efforts as customers are more likely to delay the payment of their gas bills, leading to higher-than-normal accounts receivable. This situation results in higher short-term debt levels and increased bad debt expense. Should the price of purchased gas increase significantly during the upcoming Heating Season, we would expect increases in our short-term debt, accounts receivable and bad debt expense during 2011.

Finally, higher costs of natural gas in recent years have already caused many of our utility customers to conserve in the use of our gas services and could lead to even more customers utilizing such conservation methods or switching to other competing products. The higher costs have also allowed competition from products utilizing alternative energy sources for applications that have traditionally used natural gas, encouraging some customers to move away from natural gas fired equipment to equipment fueled by other energy sources. However, natural gas prices are expected to remain lower than they have been for the last few years as a result of a robust natural gas supply, the weak economy and ample storage.

The cost of providing pension and postretirement health care benefits to eligible employees and qualified retirees is subject to changes in pension fund values and changing demographics and may have a material adverse effect on our financial results.
We have defined benefit pension and postretirement health care plans for the benefit of substantially all full-time employees and qualified retirees. The cost of providing these benefits to eligible current and former employees is subject to changes in the market value of our pension fund assets, changing demographics, including longer life expectancy of beneficiaries and changes in health care cost trends.

Any sustained declines in equity markets and reductions in bond yields may have a material adverse effect on the value of our pension funds. In these circumstances, we may be required to recognize an increased pension expense or a charge to our other comprehensive income to the extent that the pension fund values are less than the total anticipated liability under the plans. Market declines in the second half of 2008 resulted in significant losses in the value of our pension fund assets. Although the market made a recovery in 2009 and 2010 our pension fund assets are not at the levels they were prior to the market decline in 2008. As a result, based on the current funding status of the plans, we would be required to make a minimum contribution to the plans of approximately $30 million in 2011. We are planning to make additional contributions in 2011 up to $31 million, for a total of up to $61 million, in order to preserve the current level of benefits under the plans and in accordance with the funding requirements of The Pension Protection Act of 2006 (Pension Protection Act). As of December 31, 2010 our pension plans assets represented 65% 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 Postretirement Obligations" and Note 5 "Employee Benefit Plans," set forth in Item 8. "Financial Statements and Supplementary Data."

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

Risks Related to Our Corporate and Financial Structure

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

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

- adverse economic conditions
- adverse general capital market conditions
- poor performance and health of the utility industry in general
- bankruptcy or financial distress of unrelated energy companies or Marketers
- significant decrease in the demand for natural gas
- adverse regulatory actions that affect our local gas distribution companies and our natural gas storage business
- terrorist attacks on our facilities or our suppliers, or
- extreme weather conditions.

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

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

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

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

Our existing Credit Facility, Bridge Facility, Term Loan Facility and the SouthStar line of credit contain financial covenants. If we breach any of the financial covenants under these agreements, our debt repayment obligations under them could be accelerated. In such event, we may not be able to refinance or repay all our indebtedness, which would result in a material adverse effect on our business, results of operations and financial condition.

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

Our senior unsecured debt is currently assigned investment grade credit ratings. If the rating agencies downgrade our ratings, particularly below investment grade, it may significantly limit our access to the commercial paper market and our borrowing costs would increase. In addition, we would likely be required to pay a higher interest rate in future financings and our potential pool of investors and funding sources would likely decrease.

Additionally, if our credit rating by either S&P or Moody's falls to non-investment grade status, we will be required to provide additional support for certain customers of our wholesale business. In December 2010, after we announced the proposed merger with Nicor, S&P lowered our outlook from stable to negative watch, but S&P did not change our credit rating. As of December 31, 2010, if our credit rating had fallen below investment grade, we would have been required to provide collateral of approximately $39 million to continue conducting our wholesale services business with certain counterparties.

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

We are subject to interest rate risk in connection with the issuance of fixed-rate and variable-rate debt. In order to maintain our desired mix of fixed-rate and variable-rate debt, we may use interest rate swap agreements and exchange fixed-rate and variable-rate interest payment obligations over the life of the arrangements, without exchange of the underlying principal amounts. For additional information, see Item 7A, "Quantitative and Qualitative Disclosures About Market Risk." We cannot ensure that we will be successful in structuring such swap agreements to manage our risks effectively. If we are unable to do so, our earnings may be reduced. In addition, higher interest rates, all other things equal, reduce the earnings that we derive from transactions where we capture the difference between authorized returns and short-term borrowings.

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

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

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

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

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

Our Credit Facility, Bridge Facility and Term Loan Facility contain cross-default provisions. Should an event of default occur under some of our debt agreements, we face the prospect of being in default under other of our debt agreements, obligated in such instance to satisfy a large portion of our outstanding indebtedness and unable to satisfy all our outstanding obligations simultaneously.

Risks Related to Our Proposed Merger with Nicor

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

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

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

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

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

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

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

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

The merger is subject to receipt of consent or approval from governmental entities that could delay or prevent the completion of the merger or impose conditions that could have a material adverse effect on the combined company or that could cause abandonment of the merger.
To complete the merger, we and Nicor need to obtain approvals or consents from, or make filings with, a number of United States federal and state public utility, antitrust and other regulatory authorities.

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

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

We are subject to contractual restrictions in the Merger Agreement that may hinder operations pending the merger.
The Merger Agreement restricts each company, without the other's consent, from making certain acquisitions and taking other specified actions until the merger occurs or the Merger Agreement terminates. These restrictions may prevent us from pursuing otherwise attractive business opportunities and making other changes to our business prior to completion of the merger or termination of the Merger Agreement.

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

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

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

The merger may not be accretive to our earnings and may cause dilution to our earnings per share, which may negatively affect the market price of our common shares. We currently anticipate that the merger will be neutral to our earnings per share in the first full year following the completion of the merger and accretive thereafter. This expectation is based on preliminary estimates which may materially change. We may encounter additional transaction and integration-related costs, may fail to realize all of the benefits anticipated in the merger or be subject to other factors that affect preliminary estimates. Any of these factors could cause a decrease in our earnings per share or decrease or delay the expected accretive effect of the merger and contribute to a decrease in the price of our common shares.

If the merger is completed, the anticipated benefits of combining Nicor with us may not be realized. We entered into the Merger Agreement with the expectation that the merger would result in various benefits, including, among other things, increased operating efficiencies and reduced costs.

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

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

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

The integration of AGL Resources and Nicor following the merger will present significant challenges that may result in a decline in the anticipated potential benefits of the merger. The merger involves the combination of two companies that previously operated independently. The difficulties of combining the companies' operations include:

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

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

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

Current shareholders will have a reduced ownership and voting interest after the merger and will exercise less influence over management of the combined company. Upon completion of the merger we expect to issue up to approximately 38.6 million shares of common stock to Nicor shareholders in connection with the Merger Agreement. As a result, our current shareholders are expected to hold approximately 67% of the total shares of our common stock outstanding immediately following the completion of the proposed merger.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Item 1B. Unresolved Staff Comments

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

Item 2. Properties

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

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

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

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

Offices
All of our segments own or lease office, warehouse and other facilities throughout our operating areas. We expect additional or substitute space to be available as needed to accommodate expansion of our operations.

Item 3. Legal Proceedings

The nature of our business ordinarily results in periodic regulatory proceedings before various state and federal authorities. In addition, we are party, as both plaintiff and defendant, to a number of lawsuits related to our business on an ongoing basis. Management believes that the outcome of all regulatory proceedings and litigation in which we are currently involved will not have a material adverse effect on our consolidated financial condition or results of operations.

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

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

Item 5. Market for the Registrant's Common Equity, Related Stockholders Matters and Issuer Purchases of Equity Securities

Holders of Common Stock, Stock Price and Dividend Information

Our common stock is listed on the New York Stock Exchange under the symbol AGL. At February 7, 2011, there were 9,277 record holders of our common stock. Quarterly information concerning our high and low stock prices and cash dividends paid in 2010 and 2009 is as follows:

Quarter ended:	Sales price of common stock High	Low	Cash dividend per common share
March 31, 2010	$38.83	$34.26	$0.44
June 30, 2010	40.08	34.72	0.44
September 30, 2010	40.00	35.29	0.44
December 31, 2010	39.66	34.21	0.44
			$1.76

Quarter ended:	Sales price of common stock High	Low	Cash dividend per common share
March 31, 2009	$34.93	$24.02	$0.43
June 30, 2009	32.38	26.00	0.43
September 30, 2009	35.79	30.05	0.43
December 31, 2009	37.52	33.50	0.43
			$1.72

We have historically paid dividends to common shareholders four times a year: March 1, June 1, September 1 and December 1. We have paid 252 consecutive quarterly dividends beginning in 1948. Our common shareholders may receive dividends when declared at the discretion of our Board of Directors. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Cash Flow from Financing Activities – Dividends on Common Stock." Dividends may be paid in cash, stock or other form of payment, and payment of future dividends will depend on our future earnings, cash flow, financial requirements and other factors, some of which are noted below. In certain cases, our ability to pay dividends to our common shareholders is limited by the following:

- our ability to satisfy our obligations under certain financing agreements, including debt-to-capitalization covenants
- our ability to satisfy our obligations to any future preferred shareholders

Under Georgia law, the payment of cash dividends to the holders of our common stock is limited to our legally available assets and subject to the prior payment of dividends on any outstanding shares of preferred stock. Our assets are not legally available for paying cash dividends if, after payment of the dividend:

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

Issuer Purchases of Equity Securities

The following table sets forth information regarding purchases of our common stock by us and any affiliated purchasers during the three months ended December 31, 2010. Stock repurchases may be made in the open market or in private transactions at times and in amounts that we deem appropriate. However, there is no guarantee as to the exact number of additional shares that may be repurchased, and we may terminate or limit the stock repurchase program at any time. We currently anticipate holding the repurchased shares as treasury shares.

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

(1) On March 20, 2001, our Board of Directors approved the purchase of up to 600,000 shares of our common stock in the open market to be used for issuances under the Officer Incentive Plan (Officer Plan). We purchased 5,000 shares for such purposes in the fourth quarter of 2010. As of December 31, 2010, we had purchased a total 347,153 of the 600,000 shares authorized for purchase, leaving 252,847 shares available for purchase under this program.

(2) On February 3, 2006, we announced that our Board of Directors had authorized a plan to repurchase up to a total of 8 million shares of our common stock, excluding the shares remaining available for purchase in connection with the Officer Plan as described in note (1) above, over a five-year period. This repurchase plan expired January 31, 2011. However, we may request that our Board of Directors extend this plan.

Item 6. Selected Financial Data

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

Dollars and shares in millions, except per share amounts	2010	2009	2008	2007	2006
Income statement data					
Operating revenues	$2,373	$2,317	$2,800	$2,494	$2,621
Cost of gas	1,164	1,142	1,654	1,369	1,482
Operating margin [1]	1,209	1,175	1,146	1,125	1,139
Operating expenses					
Operation and maintenance	503	497	472	451	473
Depreciation and amortization	160	158	152	144	138
Taxes other than income taxes	46	44	44	41	40
Total operating expenses	709	699	668	636	651
Operating income	500	476	478	489	488
Other (expense) income	(1)	9	6	4	(1)
Earnings before interest and taxes (EBIT) [1]	499	485	484	493	487
Interest expenses	109	101	115	125	123
Earnings before income taxes	390	384	369	368	364
Income taxes	140	135	132	127	129
Net income	250	249	237	241	235
Less net income attributable to the noncontrolling interest	16	27	20	30	23
Net income attributable to AGL Resources Inc.	$234	$222	$217	$211	$212
Common stock data					
Weighted average common shares outstanding basic	77.4	76.8	76.3	77.1	77.6
Weighted average common shares outstanding diluted	77.8	77.1	76.6	77.4	78.0
Total shares outstanding [2]	78.1	77.5	76.9	76.4	77.7
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	$3.02	$2.89	$2.85	$2.74	$2.73
Diluted earnings per common share – attributable to AGL Resources Inc. common shareholders	$3.00	$2.88	$2.84	$2.72	$2.72
Dividends declared per common share	$1.76	$1.72	$1.68	$1.64	$1.48
Dividend payout ratio	58%	60%	59%	60%	54%
Dividend yield [3]	4.9%	4.7%	5.4%	4.4%	3.8%
Price range:					
High	$40.08	$37.52	$39.13	$44.67	$40.09
Low	$34.21	$24.02	$24.02	$35.24	$34.40
Close [2]	$35.85	$36.47	$31.35	$37.64	$38.91
Market value [2]	$2,800	$2,826	$2,411	$2,876	$3,023
Statements of Financial Position data [2]					
Total assets	$7,518	$7,074	$6,710	$6,258	$6,123
Property, plant and equipment – net	4,405	4,146	3,816	3,566	3,436
Total debt	2,706	2,576	2,541	2,255	2,161
Total equity	1,836	1,819	1,684	1,708	1,651
Cash flow data					
Net cash flow provided by operating activities	$526	$592	$227	$377	$351
Net cash flow used in investing activities	(442)	(476)	(372)	(253)	(248)
Net cash flow (used in) provided by financing activities	(86)	(106)	142	(122)	(118)
Net borrowings and (payments) of short-term debt	131	(264)	286	52	6
Financial ratios [2]					
Debt	60%	59%	60%	57%	57%
Equity	40%	41%	40%	43%	43%
Total	100%	100%	100%	100%	100%
Return on average equity	12.8%	12.7%	12.8%	12.6%	13.3%

(1) These are non-GAAP measurements. A reconciliation of operating margin to operating income and EBIT to earnings before income taxes and net income is contained in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations - AGL Resources-Results of Operations."

(2) As of the last day of the fiscal period.

(3) Dividends declared per common share divided by market value per common share.