AGL RESOURCES INC
Form 10-Q
October 29, 2009

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

FORM 10-Q

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

For the Quarterly Period Ended September 30, 2009

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
(Address and zip code of principal executive offices)

404-584-4000
(Registrant's telephone number, including area code)

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 (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) 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 whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” ”accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer þ	Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock as of the latest practicable date.

Class	Outstanding as of October 22, 2009
Common Stock, $5.00 Par Value	77,398,732

Glossary of Key Terms

Table of Contents

AGL RESOURCES INC.

Quarterly Report on Form 10-Q

For the Quarter Ended September 30, 2009

TABLE OF CONTENTS

Glossary of Key Terms

Table of Contents

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
Chattanooga Gas	Chattanooga Gas Company
Credit Facility	Credit agreement supporting our commercial paper program
EBIT	Earnings before interest and taxes, a non-GAAP measure that includes operating income and other income and excludes interest expense, and income tax expense; as an indicator of our operating performance, EBIT should not be considered an alternative to, or more meaningful than, operating income, net income, 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 rates mechanisms
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings
GAAP	Accounting principles generally accepted in the United States of America
Georgia Commission	Georgia Public Service Commission
GNG	Georgia Natural Gas, the name under which SouthStar does business in Georgia
Golden Triangle Storage	Golden Triangle Storage, Inc.
Heating Degree Days	A measure of the effects of weather on our businesses, calculated when the average daily actual temperatures are less than a baseline temperature of 65 degrees Fahrenheit.
Heating Season	The period from November through March when natural gas usage and operating revenues are generally higher because more customers are connected to our distribution systems when weather is colder.
Jefferson Island	Jefferson Island Storage & Hub, LLC
LOCOM	Lower of weighted average cost or current market price
Marketers	Marketers selling retail natural gas in Georgia and certificated by the Georgia Commission
Moody’s	Moody’s Investors Service
New Jersey BPU	New Jersey Board of Public Utilities
NYMEX	New York Mercantile Exchange, Inc.
OCI	Other comprehensive income
Operating margin	A non-GAAP measure of income, calculated as revenues minus cost of gas, that excludes operation and maintenance expense, depreciation and amortization, taxes other than income taxes, and the gain or loss on the sale of our assets; these items are included in our calculation of operating income as reflected in our condensed consolidated statements of income. Operating margin should not be considered an alternative to, or more meaningful than, operating income, net income, or net income attributable to AGL Resources Inc. 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
PRP	Pipeline replacement program for Atlanta Gas Light
S&P	Standard & Poor's Ratings Services
SEC	Securities and Exchange Commission
Sequent	Sequent Energy Management, L.P.
SouthStar	SouthStar Energy Services LLC
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.
WACOG	Weighted average cost of gas
WNA	Weather normalization adjustment

Table of Contents

PART 1 – Financial Information
Item 1. Financial Statements

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION
(UNAUDITED)

	As of		
In millions, except share data	Sept. 30, 2009	Dec. 31, 2008	Sept. 30, 2008
Current assets			
Cash and cash equivalents	$ 21	$ 16	$ 11
Inventories, net (Note 1)	651	663	811
Receivables			
Energy marketing receivables (Note 1)	216	549	535
Gas, unbilled and other receivables	145	472	206
Less allowance for uncollectible accounts	16	16	17
Total receivables	345	1,005	724
Derivative financial instruments – current portion (Note 2 and Note 3)	146	207	172
Unrecovered pipeline replacement program costs – current portion (Note 1)	40	41	40
Unrecovered environmental remediation costs – current portion (Note 1)	13	18	20
Other current assets	102	92	162
Total current assets	1,318	2,042	1,940
Long-term assets and other deferred debits			
Property, plant and equipment	5,791	5,500	5,377
Less accumulated depreciation	1,761	1,684	1,651
Property, plant and equipment-net	4,030	3,816	3,726
Goodwill	418	418	418
Unrecovered pipeline replacement program costs (Note 1)	169	196	202
Unrecovered environmental remediation costs (Note 1)	142	125	124
Derivative financial instruments (Note 2 and Note 3)	31	38	16
Other	75	75	78
Total long-term assets and other deferred debits	4,865	4,668	4,564
Total assets	$ 6,183	$ 6,710	$ 6,504
Current liabilities			
Short-term debt (Note 6)	$ 310	$ 866	$ 769
Energy marketing trade payables (Note 1)	245	539	568
Accounts payable - trade	155	202	181
Accrued expenses	102	113	83

Accrued pipeline replacement program costs – current portion (Note 1)	55	49	43
Customer deposits	43	50	39
Derivative financial instruments – current portion (Note 2 and Note 3)	27	50	34
Accrued environmental remediation liabilities – current portion (Note 1 and Note 7)	21	17	16
Other current liabilities	86	97	89
Total current liabilities	1,044	1,983	1,822
Long-term liabilities and other deferred credits			
Long-term debt (Note 6)	1,975	1,675	1,675
Accumulated deferred income taxes	644	571	625
Accumulated removal costs (Note 1)	194	178	176
Accrued pension obligations (Note 4)	187	199	43
Accrued environmental remediation liabilities (Note 1 and Note 7)	109	89	89
Accrued pipeline replacement program costs (Note 1)	100	140	152
Accrued postretirement benefit costs (Note 4)	41	46	19
Derivative financial instruments (Note 2 and Note 3)	4	6	8
Other long-term liabilities and other deferred credits	138	139	142
Total long-term liabilities and other deferred credits	3,392	3,043	2,929
Total liabilities and other deferred credits	4,436	5,026	4,751
Commitments and contingencies (Note 7)			
Equity			
AGL Resources Inc. common shareholders' equity, $5 par value; 750,000,000 shares authorized	1,719	1,652	1,724
Noncontrolling interest (Note 5)	28	32	29
Total equity	1,747	1,684	1,753
Total liabilities and equity	$ 6,183	$ 6,710	$ 6,504

See Notes to Condensed Consolidated Financial Statements (Unaudited).

Glossary of Key Terms

Table of Contents

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(UNAUDITED)

	Three months ended September 30,		Nine months ended September 30,	
In millions, except per share amounts	2009	2008	2009	2008
Operating revenues	$ 307	$ 539	$ 1,679	$ 1,995
Operating expenses				
Cost of gas	99	261	840	1,193
Operation and maintenance	115	104	359	337
Depreciation and amortization	40	38	118	112
Taxes other than income taxes	10	10	34	33
Total operating expenses	264	413	1,351	1,675
Operating income	43	126	328	320
Other income	2	2	7	6
Interest expense, net	(26)	(29)	(75)	(85)
Earnings before income taxes	19	99	260	241
Income tax expense	7	39	92	86
Net income	12	60	168	155
Less net (loss) income attributable to the noncontrolling interest (Note 5)	-	(5)	17	12
Net income attributable to AGL Resources Inc.	$ 12	$ 65	$ 151	$ 143
Per common share data (Note 1)				
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	$ 0.16	$ 0.85	$ 1.97	$ 1.87
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	$ 0.16	$ 0.85	$ 1.97	$ 1.87
Cash dividends declared per common share	$ 0.43	$ 0.42	$ 1.29	$ 1.26
Weighted-average number of common shares outstanding (Note 1)				
Basic	76.9	76.4	76.7	76.2
Diluted	77.2	76.6	76.9	76.5

See Notes to Condensed Consolidated Financial Statements (Unaudited).

Glossary of Key Terms

Table of Contents

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF EQUITY
(UNAUDITED)

	AGL Resources Inc. Common Shareholders Equity							
	Common stock		Premium on common	Earnings	Accumulated other comprehensive	Treasury	Noncontrolling	
In millions, except per share amounts	Shares	Amount	stock	reinvested	loss	shares	interest	Total
Balance as of December 31, 2007	76.4	$ 390	$ 667	$ 680	$ (13)	$ (63)	$ 47	$ 1,708
Net income	-	-	-	143	-	-	12	155
Other comprehensive loss	-	-	-	-	(1)	-	-	(1)
Dividends on common stock ($1.26 per share)	-	-	-	(96)	-	3	-	(93)
Distributions to noncontrolling interest	-	-	-	-	-	-	(30)	(30)
Issuance of treasury shares	0.4	-	(1)	(4)	-	12	-	7
Stock-based compensation expense (net of taxes) (Note 1)	-	-	7	-	-	-	-	7
Balance as of September 30, 2008	76.8	$ 390	$ 673	$ 723	$ (14)	$ (48)	$ 29	$ 1,753

	AGL Resources Inc. Common Shareholders Equity							
	Common stock		Premium on common	Earnings	Accumulated other comprehensive	Treasury	Noncontrolling	
In millions, except per share amounts	Shares	Amount	stock	reinvested	loss	shares	interest	Total
Balance as of December 31, 2008	76.9	$ 390	$ 676	$ 763	$ (134)	$ (43)	$ 32	$ 1,684
Net income	-	-	-	151	-	-	17	168
Other comprehensive loss	-	-	-	-	-	-	(1)	(1)
Dividends on common stock ($1.29 per share)	-	-	-	(99)	-	3	-	(96)
Distributions to noncontrolling interest	-	-	-	-	-	-	(20)	(20)
Issuance of treasury shares	0.5	-	(6)	(4)	-	16	-	6
Stock-based compensation expense (net of taxes) (Note 1)	-	-	6	-	-	-	-	6

Balance as of September 30, 2009	77.4	$ 390	$ 676	$ 811	$ (134)	$ (24)	$ 28	$ 1,747

See Notes to Condensed Consolidated Financial Statements (Unaudited).

Glossary of Key Terms

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

In millions	Three months ended September 30, 2009	Three months ended September 30, 2008	Nine months ended September 30, 2009	Nine months ended September 30, 2008
Comprehensive income attributable to AGL Resources Inc. (net of tax)				
Net income attributable to AGL Resources Inc.	$ 12	$ 65	$ 151	$ 143
Cash flow hedges:				
Derivative financial instruments unrealized (losses) gains arising during the period	(1)	(1)	(12)	3
Reclassification of derivative financial instruments realized losses (gains) included in net income	4	1	12	(4)
Other comprehensive income (loss)	3	-	-	(1)
Comprehensive income (Note 1)	$ 15	$ 65	$ 151	$ 142
Comprehensive income (loss) attributable to noncontrolling interest (net of tax)				
Net income (loss) attributable to noncontrolling interest	$ -	$ (5)	$ 17	$ 12
Cash flow hedges:				
Derivative financial instruments unrealized (losses) gains arising during the period	-	1	(6)	3
Reclassification of derivative financial instruments realized losses (gains) included in net income	1	(1)	5	(3)
Other comprehensive income (loss)	1	-	(1)	-
Comprehensive income (loss) (Note 1)	$ 1	$ (5)	$ 16	$ 12
Total comprehensive income (net of tax)				
Net income	$ 12	$ 60	$ 168	$ 155
Cash flow hedges:				
Derivative financial instruments unrealized (losses) gains arising during the period	(1)	-	(18)	6
Reclassification of derivative financial instruments realized losses (gains) included in net income	5	-	17	(7)
Other comprehensive income (loss)	4	-	(1)	(1)
Comprehensive income (Note 1)	$ 16	$ 60	$ 167	$ 154

See Notes to Condensed Consolidated Financial Statements (Unaudited).

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

In millions	Nine months ended September 30, 2009	2008
Cash flows from operating activities		
Net income	$ 168	$ 155
Adjustments to reconcile net income to net cash flow provided by operating activities		
Depreciation and amortization	118	112
Deferred income taxes	62	66
Change in derivative financial instrument assets and liabilities	43	(86)
Changes in certain assets and liabilities		
Gas, unbilled and other receivables	327	202
Energy marketing receivables and energy marketing trade payables, net	39	53
Inventories	12	(260)
Gas and trade payables	(47)	9
Other – net	(36)	(79)
Net cash flow provided by operating activities	686	172
Cash flows from investing activities		
Payments to acquire, property, plant and equipment	(314)	(254)
Net cash flow used in investing activities	(314)	(254)
Cash flows from financing activities		
Issuance of senior notes	300	-
Net payments and borrowings of short-term debt	(556)	189
Dividends paid on common shares	(96)	(93)
Distribution to noncontrolling interest	(20)	(30)
Payments of long-term debt	-	(161)
Issuance of variable rate gas facility revenue bonds	-	161
Issuance of treasury shares and other	5	8
Net cash flow (used in) provided by financing activities	(367)	74
Net increase (decrease) in cash and cash equivalents	5	(8)
Cash and cash equivalents at beginning of period	16	19
Cash and cash equivalents at end of period	$ 21	$ 11
Cash paid during the period for		
Interest	$ 74	$ 88

Income taxes	$ 50	$ 27

See Notes to Condensed Consolidated Financial Statements (Unaudited).

Glossary of Key Terms

Table of Contents

AGL RESOURCES INC. AND SUBSIDIARIES NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Note 1 - Accounting Policies and Methods of Application

General

AGL Resources Inc. is an energy services holding company that conducts substantially all of its operations through its subsidiaries. Unless the context requires otherwise, references to “we,” “us,” “our,” or “the company” mean consolidated AGL Resources Inc. and its subsidiaries (AGL Resources).

The year-end condensed statement of financial position data was derived from our audited financial statements, but does not include all disclosures required by GAAP. We have prepared the accompanying unaudited condensed consolidated financial statements under the rules of the SEC. Under such rules and regulations, we have condensed or omitted certain information and notes normally included in financial statements prepared in conformity with GAAP. However, the condensed consolidated financial statements reflect all adjustments of a normal recurring nature that are, in the opinion of management, necessary for a fair presentation of our financial results for the interim periods. For a glossary of key terms, see page 3. You should read these condensed consolidated financial statements in conjunction with our recast consolidated financial statements and related notes as filed on Form 8-K with the SEC on July 13, 2009, and in our Form 10-K for the year ended December 31, 2008, filed with the SEC on February 5, 2009.

Due to the seasonal nature of our business, our results of operations for the three and nine months ended September 30, 2009 and 2008, and our financial condition as of December 31, 2008, and September 30, 2009 and 2008, are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period.

Basis of Presentation

Our condensed consolidated financial statements include our accounts, the accounts of our majority-owned and controlled subsidiaries and the accounts of variable interest entities for which we are the primary beneficiary. This means that our accounts are combined with our subsidiaries’ accounts. We have eliminated any intercompany profits and transactions in consolidation; however, we have not eliminated intercompany profits when such amounts are probable of recovery under the affiliates’ rate regulation process. Certain amounts from prior periods have been reclassified and revised to conform to the current period presentation.

Use of Accounting Estimates

The preparation of our financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We based our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances, and we evaluate our estimates on an ongoing basis. Each of our estimates involves complex situations requiring a high degree of judgment either in the application and interpretation of existing financial accounting literature or in the development of estimates that impact our financial statements. The most significant estimates include our PRP accruals, ERC liability accruals, allowance for uncollectible accounts, contingencies, pension and postretirement obligations, derivative and hedging activities, unbilled revenues and provision for income taxes. Our actual results could differ from our estimates, and such differences could be material.

Energy Marketing Receivables and Payables

Our wholesale services segment provides services to retail and wholesale marketers and utility and industrial customers. These customers, also known as counterparties, utilize netting agreements, which enable wholesale services to net receivables and payables by counterparty. Wholesale services also nets across product lines and against cash collateral, provided the master netting and cash collateral agreements include such provisions. The amounts due from or owed to wholesale services’ counterparties are netted and recorded on our condensed 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 September 30, 2009, December 31, 2008 and September 30, 2008, the collateral that wholesale services would have been required to post 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 impaired.

Glossary of Key Terms

Table of Contents

Regulatory Assets and Liabilities

We have recorded regulatory assets and liabilities in our condensed consolidated statements of financial position in accordance with authoritative guidance related to regulated operations. These regulatory assets and liabilities, along with the associated assets and liabilities, are summarized in the following table.

In millions	Sept. 30 2009	Dec. 31 2008	Sept. 30 2008
Regulatory assets			
Unrecovered PRP costs	$ 209	$ 237	$ 242
Unrecovered ERC	155	143	144
Unrecovered postretirement benefit costs	10	11	11
Unrecovered seasonal rates	10	11	10
Unrecovered natural gas costs	-	19	33
Other	27	30	31
Total regulatory assets	411	451	471
Associated assets			
Derivative financial instruments	13	23	15
Total regulatory and associated assets	$ 424	$ 474	$ 486
Regulatory liabilities			
Accumulated removal costs (1)	$ 194	$ 178	$ 176
Deferred natural gas costs	26	25	14
Derivative financial instruments	13	23	15
Regulatory tax liability	17	19	19
Unamortized investment tax credit	13	14	15
Other	18	22	21
Total regulatory liabilities	281	281	260
Associated liabilities			
PRP costs	155	189	195
ERC	118	96	95
Total associated liabilities	273	285	290
Total regulatory and associated liabilities	$ 554	$ 566	$ 550

(1) Increase for 2009 primarily due to Virginia Natural Gas rate change based on most recently approved depreciation study.

There have been no significant changes to our regulatory assets and liabilities as described in Note 1 to our recast consolidated financial statements and related notes as filed on Form 8-K with the SEC on July 13, 2009, and in our Form 10-K for the year ended December 31, 2008, filed with the SEC on February 5, 2009. For more information on our derivative financial instruments, see Note 3.

Inventories

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

Sequent and SouthStar evaluate the average cost of their natural gas inventories against market prices to determine whether any declines in market prices below the WACOG are other than temporary. For any declines considered to be other than temporary, we record adjustments to reduce the weighted average cost of the natural gas inventory to market price. SouthStar and Sequent did not record LOCOM adjustments in the three months ended September 30, 2009. SouthStar recorded LOCOM adjustments of $6 million in the nine months ended September 30, 2009 and $18 million in the three and nine months ended September 30, 2008. Sequent recorded LOCOM adjustments of $8 million in the nine months ended September 30, 2009 and $34 million for the three and nine months ended September 30, 2008.

Earnings per Common Share

We compute basic earnings per common share by dividing our net income attributable to our common shareholders by the daily weighted-average number of common shares outstanding. Diluted earnings per common share reflect the potential reduction in earnings per common share that could occur when potentially dilutive common shares are added to common shares outstanding. We adopted new authoritative guidance related to earnings per share on January 1, 2009. The effect of the guidance on the computation of earnings per share for unvested share awards outstanding that have the nonforfeitable right to receive dividends was immaterial to our calculation of earnings per share.

We derive our potentially dilutive common shares by calculating the number of shares issuable under restricted stock, restricted stock units and stock options. The future issuance of shares underlying the restricted stock and restricted stock units depends on the satisfaction of certain performance criteria. The future issuance of shares underlying the outstanding stock options depends upon 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 for the periods presented, assuming restricted stock and restricted stock units currently awarded under the plan ultimately vest and stock options currently exercisable at prices below the average market prices are exercised.

	Three months ended September 30,	
In millions	2009	2008
Denominator for basic earnings per share (1)	76.9	76.4
Assumed exercise of restricted stock, restricted stock units and stock options	0.3	0.2
Denominator for diluted earnings per share	77.2	76.6

(1) Daily weighted-average shares outstanding.

	Nine months ended September 30,	
In millions	2009	2008
	76.7	76.2

Denominator for basic earnings per share (1)		
Assumed exercise of restricted stock, restricted stock units and stock options	0.2	0.3
Denominator for diluted earnings per share	76.9	76.5

(1) Daily weighted-average shares outstanding.

Glossary of Key Terms

Table of Contents

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

	September 30,	
In millions	2009	2008
Three months ended	1.6	2.1
Nine months ended	2.2	1.6

The decrease of 0.5 million in anti-dilutive shares for the three months ended September 30, 2009, was primarily a result of a higher average market value of our common shares compared to the same period of 2008. The increase of 0.6 million in anti-dilutive shares for the nine months ended September 30, 2009, is primarily a result of a lower average market value of our common shares compared to the same period of 2008.

Stock-Based Compensation

In the first nine months of 2009, we issued grants of approximately 250,000 stock options and 211,000 restricted stock units, which will result in the recognition of approximately $2 million of stock-based compensation expense in 2009. No material share awards have been granted to employees whose compensation is subject to capitalization. We use the Black-Scholes option pricing model to determine the fair value of the options granted. On an annual basis, we evaluate the assumptions and estimates used to calculate our stock-based compensation expense.

There have been no significant changes to our stock-based compensation, as described in Note 4 to our recast consolidated financial statements and related notes as filed on Form 8-K with the SEC on July 13, 2009, and in our Form 10-K for the year ended December 31, 2008, filed with the SEC on February 5, 2009.

Comprehensive Income

Our comprehensive income or loss includes net income plus OCI, which includes other gains and losses affecting equity that GAAP excludes from net income. Such items consist primarily of gains and losses on certain derivatives designated as cash flow hedges and unfunded or overfunded pension and postretirement obligation adjustments. Our cumulative comprehensive income or loss that has been excluded from net income is reported as accumulated other comprehensive loss within our condensed consolidated statement of equity.

Subsequent Events

In May 2009, the FASB issued authoritative guidance related to subsequent events, which is effective for reporting periods ending after June 15, 2009. The FASB establishes guidance for and disclosure of events that occur after the statement of financial position date, but before financial statements are issued, or are available to be issued. Prior guidance relating to subsequent events was primarily directed toward auditors, not management. However, the guidance should now be applied by management to the accounting for and disclosure of subsequent events, but does not apply to subsequent events or transactions that are within the scope of other applicable GAAP that provide different guidance. In accordance with the guidance, we evaluated subsequent events until the time that our financial statements were issued and filed with the SEC on October 29, 2009.

Accounting Developments

In June 2009, the FASB issued authoritative guidance, which replaces the previous authoritative hierarchy aspect of GAAP. The guidance creates a two-level GAAP hierarchy - authoritative and non-authoritative - and establishes the guidance as the sole source of authoritative GAAP guidance for non-governmental entities, except for rules and releases by the SEC.

After July 1, 2009, all non-grandfathered, non-SEC accounting guidance not included in the authoritative guidance is superseded and is deemed non-authoritative. The guidance is effective for financial statements issued for interim and annual periods ending after September 15, 2009. We adopted the guidance on September 30, 2009, which had no impact on our condensed consolidated results of operations, cash flows or financial position.

Note 2 - Fair Value Measurements

The carrying value of cash and cash equivalents, receivables, accounts payable, short-term debt, other current assets and liabilities, derivative financial instrument assets, derivative financial instrument liabilities and accrued interest approximate fair value.

New authoritative guidance related to fair value measurements and disclosures was effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. In December 2007, the FASB provided a one-year deferral of the guidance for nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value on a recurring basis, at least annually. We adopted this guidance on January 1, 2008, for our financial assets and liabilities, which primarily consist of derivatives we record in accordance with the guidance related to derivatives and hedging. We adopted the guidance for our nonfinancial assets and liabilities on January 1, 2009, which had no impact to our condensed consolidated results of operations, cash flows or financial condition.

In August 2009, the FASB updated this guidance to provide clarity on the methodologies and disclosures for fair value measurement estimates of liabilities that do not have a quoted price in an active market, level 3 liabilities (refer to Level 3 discussion contained in this Note). Any revisions due to a change in valuation technique, or its application, are to be accounted for as a change in accounting method. Disclosure is required for any change in valuation technique or related inputs resulting from the application of this update and the total effect would need to be quantified, if practicable. This update is effective for reporting periods ending after September 15, 2009, and had no financial impact to our condensed consolidated results of operations, cash flows or financial position.

Glossary of Key Terms

Additional new authoritative guidance related to fair value measurements and disclosures established a two-step process to determine if the market for a financial asset is inactive and a transaction is not distressed. Step 1 provides factors that include, but are not limited to: transaction frequency, varying price quotations, index correlation, liquidity risk premiums, price spread increases and availability of public information. If a company determines the market is inactive, Step 2 must be applied.

In Step 2 an entity must presume that a quoted price is associated with a distressed transaction unless there was sufficient time before the measurement date to allow for usual and customary marketing activities, including multiple bidders. This guidance is effective for interim and annual periods ending after June 15, 2009. We adopted this guidance in the second quarter of 2009. Currently, this guidance does not affect us, as our financial assets are traded in active markets.

As defined in authoritative guidance related to fair value measurements and disclosures, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. We primarily apply the market approach for recurring fair value measurements and 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. This accounting guidance also 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 financial instruments with exchange-traded derivatives.

Level 2

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

Level 3

Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management’s best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to customers' needs. We do not have any material assets or liabilities classified as level 3.

The following table sets forth, by level within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2009. As required by the guidance, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

Our exchange-traded derivative contracts, which include futures and exchange-traded options, are generally based on unadjusted quoted prices in active markets and are classified within level 1. Some exchange-traded derivatives are valued using broker or dealer quotation services, or market transactions in either the listed or OTC markets, which are classified within level 2.

Glossary of Key Terms

Table of Contents

The determination of the fair values in the following table incorporates various factors required under the authoritative guidance related to fair value measurements and disclosures. 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 effect of our nonperformance risk on our liabilities. For more information on our derivative financial instruments, see Note 3.

	Recurring fair values					
	Natural gas derivative financial instruments					
	September 30, 2009		December 31, 2008		September 30, 2008	
In millions	Assets (1)	Liabilities	Assets (1)	Liabilities	Assets (1)	Liabilities
Quoted prices in active markets (Level 1)	$ 41	$ (78)	$ 52	$ (117)	$ 59	$ (32)
Significant other observable inputs (Level 2)	115	(17)	154	(28)	102	(36)
Netting of cash collateral	18	64	35	89	26	26
Total carrying value (2)	$ 174	$ (31)	$ 241	$ (56)	$ 187	$ (42)

(1) $3 million premium at September 30, 2009, $4 million at December 31, 2008 and $1 million at September 30, 2008 associated with weather derivatives have been excluded as they are based on intrinsic value, not fair value. For more information see Note 3.

(2) There were no significant unobservable inputs (level 3) for any of the periods presented.

Note 3 - Derivative Financial Instruments

Netting of Cash Collateral with Derivative Financial Instruments under Master Netting Arrangements

We maintain accounts with exchange brokers to facilitate financial derivative transactions in support of our energy marketing and risk management activities. Based on the value of our positions in these accounts and the associated margin requirements, we may be required to deposit cash into these broker accounts. We are required to offset this cash collateral with the associated fair value of the derivative financial instruments. Our cash collateral amounts are provided in the following table.

		As of	
In millions	Sept. 30, 2009	Dec. 31, 2008	Sept. 30, 2008
Right to reclaim cash collateral	$ 82	$ 128	$ 53
Obligations to return cash collateral	-	(4)	(1)
Total cash collateral	$ 82	$ 124	$ 52

Derivative Financial Instruments

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

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

Our derivative financial instruments do not contain any material credit-risk-related or other contingent features that could increase the payments for collateral we post in the normal course of business when our financial instruments are in net liability positions. For information on our energy marketing receivables and payables, which do have credit-risk-related or other contingent features, refer to Note 1. Our derivatives are included within operating cash flows as a source of cash totaling $43 million in 2009 and a use of cash totaling $86 million in 2008.

We adopted the new authoritative accounting guidance related to derivatives and hedging on January 1, 2009, which requires specific disclosures regarding how and why we use derivative instruments; the accounting for derivative instruments and related hedged items; and how derivative instruments and related hedged items affect our financial position, results of operations and cash flows. As this guidance only requires additional disclosures concerning derivatives and hedging activities, it did not have an impact on our condensed consolidated financial position, results of operations or cash flows.

Additional new accounting guidance related to derivatives and hedging requires more detailed disclosures about credit derivatives, including the potential adverse effects of changes in credit risk on the financial position, financial performance and cash flows of the sellers of the instruments. This authoritative guidance had no financial impact to our condensed consolidated results of operations, cash flows or financial condition.

Glossary of Key Terms

Table of Contents

Natural Gas Derivative Financial Instruments

The fair value of natural gas derivative financial instruments we use to manage exposures arising from changing natural gas prices reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains or losses on open contracts. We use external market quotes and indices to value substantially all the derivative financial instruments we use.

Distribution Operations In accordance with a directive from the New Jersey BPU, Elizabethtown Gas enters into derivative financial instruments to hedge the impact of market fluctuations in natural gas prices. Pursuant to the authoritative guidance related to derivatives and hedging, such derivative transactions are accounted for at fair value each reporting period in our condensed consolidated statements of financial position. In accordance with regulatory requirements realized gains and losses related to these derivatives are reflected in natural gas costs and ultimately included in billings to customers. However, these derivative financial instruments are not designated as hedges in accordance with the guidance. For more information on our regulatory assets and liabilities see Note 1.

Retail Energy Operations We have designated a portion of SouthStar's derivative financial instruments, consisting of financial swaps to manage the risk associated with forecasted natural gas purchases and sales, as cash flow hedges under the authoritative guidance related to derivatives and hedging. We record derivative gains or losses arising from cash flow hedges in OCI and reclassify them into earnings in the same period as the settlement of the underlying hedged item.

SouthStar currently has minimal hedge ineffectiveness defined as when the gains or losses on the hedging instrument do not offset the losses or gains on the hedged item. This cash flow hedge ineffectiveness is recorded in cost of gas in our condensed consolidated statements of income in the period in which it occurs. We have not designated the remainder of SouthStar's derivative financial instruments as hedges under the authoritative guidance related to derivatives and hedging and, accordingly, we record changes in their fair value within cost of gas in our condensed consolidated statements of income in the period of change. For more information on SouthStar's gains and losses reported within comprehensive income that affect equity, see our condensed consolidated statements of comprehensive income (loss). SouthStar has hedged its exposures to natural gas price risk to varying degrees in the markets in which it serves retail, commercial and industrial customers. Approximately 42% of SouthStar's purchase instruments and 46% of its sales instruments are scheduled to mature in 2009 and the remaining 58% and 54%, respectively, from January 2010 through March 2012.

SouthStar also enters into both exchange and OTC derivative financial instruments to hedge natural gas price risk. Credit risk is mitigated for exchange transactions through the backing of the NYMEX member firms. For OTC transactions, SouthStar utilizes master netting arrangements to reduce overall credit risk. As of September 30, 2009, SouthStar's maximum exposure to any single OTC counterparty was $7 million.

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 actually 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 condensed consolidated statements of financial position, with changes in fair value recorded in our condensed consolidated statements of income in the period of change. However, these futures contracts are not designated as hedges in accordance with the guidance.

The purchase, transportation, storage and sale of natural gas are accounted for on a weighted average cost or accrual basis, as appropriate, rather than on the fair value basis we utilize for the derivatives used to mitigate the natural gas price risk associated with our storage portfolio. This difference in accounting can result in volatility in our reported earnings, even though the economic margin is essentially unchanged from the date the transactions were consummated. Approximately 96% of Sequent's purchase instruments and 97% of its sales instruments are scheduled to mature in less than 2 years and the remaining 4% and 3%, respectively, in 3 to 9 years.

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

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

Glossary of Key Terms

Table of Contents

Weather Derivative Financial Instruments

In 2009 and 2008, SouthStar entered into weather derivative contracts as economic hedges of operating margins in the event of warmer-than-normal and colder-than-normal weather in the heating season, primarily from November through March. SouthStar accounts for these contracts using the intrinsic value method under the authoritative guidance related to financial instruments, and accordingly these weather derivative financial instruments are not designated as derivatives or hedges and has recorded a current asset of $3 million at September 30, 2009, $4 million at December 31, 2008 and $1 million at September 30, 2008. SouthStar recognized losses on its weather derivative financial instruments of $4 million for the nine months ended September 30, 2009 and $5 million for the nine months ended September 30, 2008 which was reflected in cost of gas on our condensed consolidated statements of income.

Quantitative Disclosures Related to Derivative Financial Instruments

As of September 30, 2009, our derivative financial instruments were comprised of both long and short natural gas positions. A long position is a contract to purchase natural gas, and a short position is a contract to sell natural gas. As of September 30, 2009, we had net long natural gas contracts outstanding in the following quantities:

	Natural gas contracts (in Bcf)				
Hedge designation	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Consolidated
Cash flow	-	2	-	2	4
Not designated	18	9	36	-	63
Total	18	11	36	2	67

Derivative Financial Instruments on the Condensed Consolidated Statements of Income

The following table presents the gain or (loss) on derivative financial instruments in our condensed consolidated statements of income for the three and nine months ended September 30, 2009.

	Three months ended September 30, 2009		Nine months ended September 30, 2009	
In millions	Retail energy operations	Wholesale services	Retail energy operations	Wholesale services
Designated as cash flow hedges under authoritative guidance related to derivatives and hedging				
Natural gas contracts – loss reclassified from OCI into cost of gas for settlement of hedged item	$ (8)	$ -	$ (25)	$ -
Not designated as hedges under authoritative guidance related to derivatives and hedging:				
Natural gas contracts – fair value adjustments recorded in operating revenues (1)	-	8	-	50
Natural gas contracts – fair value adjustments recorded in cost of gas (2)	-	-	-	-

Total (losses) gains on derivative instruments	$ (8)	$ 8	$ (25)	$ 50

(1) Associated with the fair value of existing derivative instruments at September 30, 2009.
(2) Excludes $4 million of losses recorded in cost of gas associated with weather derivatives for the nine months ended September 30, 2009.

The following amounts (pre-tax) represent the expected recognition in our condensed consolidated statements of income of the deferred losses recorded in OCI associated with retail energy operations' derivative instruments, based upon the fair values of these financial instruments as of September 30, 2009:

In millions	Retail energy operations
Designated as hedges under authoritative guidance related to derivatives and hedging	
Natural gas contracts – expected net loss reclassified from OCI into cost of gas for settlement of hedged item over next twelve months	$ (11)

Derivative Financial Instruments on the Condensed Consolidated Statements of Financial Position

In accordance with regulatory requirements, any realized gains and losses on derivative financial instruments used in our distribution operations segment are reflected in deferred natural gas costs within our condensed consolidated statements of financial position as indicated in the following table.

Table of Contents

In millions	Three months ended September 30, 2009	Nine months ended September 30, 2009
Elizabethtown Gas recognized losses on its derivative financial instruments reclassified to deferred natural gas costs	$ (10)	$ (30)

The following table presents the fair value and statements of financial position classification of our derivative financial instruments by operating segment.

		As of September 30, 2009 (2)				
In millions	Statements of financial position location (1)	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Consolidated
Designated as cash flow hedges under authoritative guidance related to derivatives and hedging						
Asset Financial Instruments						
Current natural gas contracts	Derivative financial instruments assets and liabilities – current portion	$ -	$ 14	$ -	$ -	$ 14
Noncurrent natural gas contracts	Derivative financial instruments assets and liabilities	-	-	-	1	1
Liability Financial Instruments						
Current natural gas contracts	Derivative financial instruments assets and liabilities – current portion	-	(8)	-	-	(8)
Noncurrent natural gas contracts	Derivative financial instruments assets and liabilities	-	-	-	-	-
Total		-	6	-	1	7
Not designated as hedges under authoritative guidance related to derivatives and hedging:						
Asset Financial Instruments						
Current natural gas contracts	Derivative financial instruments assets and liabilities – current portion	12	3	353	-	368

Noncurrent natural gas contracts	Derivative financial instruments assets and liabilities	1	-	59	-	60
Liability Financial Instruments						
Current natural gas contracts	Derivative financial instruments assets and liabilities – current portion	(12)	(4)	(323)	-	(339)
Noncurrent natural gas contracts	Derivative financial instruments assets and liabilities	(1)	-	(34)		(35)
Total		-	(1)	55	-	54
Total derivative financial instruments		$ -	$ 5	$ 55	$ 1	$ 61

(1) These amounts are netted within our condensed consolidated statements of financial position. Some of our derivative financial instruments have asset positions which are presented as a liability in our condensed consolidated statements of financial position, and we have derivative instruments that have liability positions which are presented as an asset in our condensed 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. Additionally, the amounts above do not include $82 million of cash collateral held on deposit in broker margin accounts as of September 30, 2009. As a result, the amounts above will differ from the amounts presented on our condensed consolidated statements of financial position, and the fair value information presented for our derivative financial instruments in Note 2.

Glossary of Key Terms

Note 4 - Employee Benefit Plans

The authoritative guidance for retirement benefits requires disclosures relating to postretirement benefit plan assets to provide transparency regarding the types of assets and the associated risks within the types of plan assets. The required disclosures include:

- How investment allocation decisions are made, including information that provides an understanding of investment policies and strategies,
- The major categories of plan assets,
- Inputs and valuation techniques used to measure the fair value of plan assets, including those measurements using significant unobservable inputs, on changes in plan assets for the period, and
- Significant concentrations of risk within plan assets.

This accounting guidance is effective for fiscal years ending after December 15, 2009 and requires additional disclosures in our notes to condensed consolidated financial statements, but will not have a material impact on our condensed consolidated financial position, results of operations or cash flows.

Pension Benefits

We sponsor two tax-qualified defined benefit retirement plans for our eligible employees, the AGL Resources Inc. Retirement Plan and the Employees' Retirement Plan of NUI Corporation. A defined benefit plan specifies the amount of benefits an eligible participant eventually will receive using information about the participant. Following are the combined cost components of our two defined pension plans for the periods indicated.

	Three months ended September 30,	
In millions	2009	2008
Service cost	$ 2	$ 2
Interest cost	7	7
Expected return on plan assets	(6)	(9)
Amortization of prior service cost	(1)	-
Recognized actuarial loss	2	-
Net pension benefit cost	$ 4	$ -

	Nine months ended September 30,	
In millions	2009	2008
Service cost	$ 6	$ 6

Interest cost	20	20
Expected return on plan assets	(21)	(25)
Amortization of prior service cost	(2)	(1)
Recognized actuarial loss	7	2
Net pension benefit cost	$ 10	$ 2

Our employees do not contribute to these retirement plans. We fund the plans by contributing at least the minimum amount required by applicable regulations and as recommended by our actuary. However, we may also contribute in excess of the minimum required amount. We calculate the minimum amount of funding using the projected unit credit cost method. The Pension Protection Act (the Act) of 2006 contained new funding requirements for single employer defined benefit pension plans. The Act established a 100% funding target for plan years beginning after December 31, 2007. However, a delayed effective date of 2011 may apply if the pension plan meets the following targets: 92% funded in 2008; 94% funded in 2009; and 96% funded in 2010. In December 2008, the Worker, Retiree and Employer Recovery Act of 2008 allowed us to measure our 2008 and 2009 funding target at 92%. In the first nine months of 2009, we contributed $21 million to our qualified pension plans and we contributed an additional $3 million in October 2009. We do not expect to make any additional contributions during the remainder of 2009. In 2008, we did not make a contribution, as one was not required for our pension plans.

Postretirement Benefits

The Health and Welfare Plan for Retirees and Inactive Employees of AGL Resources Inc. (AGL Postretirement Plan) covers all eligible AGL Resources employees who were employed as of June 30, 2002, if they reach retirement age while working for us. Eligibility for benefits under the AGL Postretirement Plan is based on age and years of service. The state regulatory commissions have approved phase-ins that defer a portion of other postretirement benefits expense for future recovery. 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. Effective January 1, 2006, benefits for prescription drugs were not provided under the plan to individuals who are eligible to receive prescription drug benefits under Medicare Part D. Medicare-eligible participants in the AGL Postretirement Plan receive prescription drug benefits through a Medicare Part D plan offered by a third party and to which we subsidize participant premiums. Medicare-eligible retirees who opt out of the AGL Postretirement Plan are eligible to receive a cash subsidy which may be used towards eligible prescription drug expenses. As of July 1, 2009, we discontinued providing medical coverage for our Medicare eligible retirees, affecting over 80% of our approximately 2,400 retirees. Those eligible retirees now receive a contribution toward coverage obtained from independent providers. Contributions are $120 per month to $240 per month depending on the coverage. We continue to provide medical coverage to pre-Medicare eligible retirees.

Glossary of Key Terms

Table of Contents

Following are the cost components of the AGL Postretirement Plan for the periods indicated.

	Three months ended September 30,	
In millions	2009	2008
Service cost	$ -	$ -
Interest cost	1	1
Expected return on plan assets	(1)	(1)
Amortization of prior service cost	(1)	(1)
Recognized actuarial loss	1	-
Net postretirement benefit cost	$ -	$ (1)

	Nine months ended September 30,	
In millions	2009	2008
Service cost	$ -	$ 1
Interest cost	4	4
Expected return on plan assets	(3)	(4)
Amortization of prior service cost	(3)	(3)
Recognized actuarial loss	2	-
Net postretirement benefit cost	$ -	$ (2)

Employee Savings Plan Benefits

We sponsor the Retirement Savings Plus Plan (RSP Plan), a defined contribution benefit plan that allows eligible participants to make contributions to their accounts up to specified limits. Under the RSP Plan, we made $5 million in matching contributions to participant accounts in the first nine months of 2009 and $5 million in the same period last year.

Note 5 – Variable Interest Entity

In June 2009, the FASB issued an amendment to the guidance related to transfers and servicing of financial assets and interests in a variable interest entity (VIE) that requires improved disclosures about transfers of financial assets and removes the exception from applying the guidance related to consolidations specifically for VIE's to qualifying special purpose entities. The amendment to the guidance will be effective for us on January 1, 2010 and it will have no effect on our consolidated results of operations, cash flows or financial position.

In June 2009, the FASB issued new consolidation guidance for a VIE. The guidance requires a company to assess the determination of the primary beneficiary of a VIE based on whether the company has the power to direct matters that most significantly impact the activities of the VIE and has the obligation to absorb losses or the right to receive benefits of the VIE. In addition, the guidance requires ongoing reassessments of whether a company is the primary beneficiary of a VIE. The guidance will be effective for us on January 1, 2010. Earlier application is prohibited. We are currently evaluating the impact of this guidance on our consolidated results of operations, cash flows and financial position.

Noncontrolling Interests

We currently own a noncontrolling 70% financial interest in SouthStar, a joint venture with Piedmont who owns the remaining 30%. Our 70% interest is noncontrolling because all significant management decisions require approval by both owners. Although our ownership interest in the SouthStar partnership is 70%, under an amended and restated joint venture agreement executed in March 2004, SouthStar's earnings are currently allocated 75% to us and 25% to Piedmont except for earnings related to customers in Ohio and Florida, which are currently allocated 70% to us and 30% to Piedmont.

We are the primary beneficiary of SouthStar's activities and have determined that SouthStar is a VIE as defined by the authoritative guidance related to consolidations, which requires us to consolidate the VIE. The assets, liabilities, and noncontrolling interests of a consolidated VIE are accounted for in our condensed consolidated financial statements as if the entity were consolidated based on voting interests.

We determined that SouthStar was a VIE because our equal voting rights with Piedmont are not proportional to our economic obligation to absorb 75% of any losses or residual returns from SouthStar, except those losses and returns related to customers in Ohio and Florida. In addition, SouthStar obtains substantially all its transportation capacity for delivery of natural gas through our wholly-owned subsidiary, Atlanta Gas Light.

On January 1, 2009, we adopted additional authoritative guidance relating to consolidations, and applied the presentation and disclosure requirements retrospectively for all periods presented. The additional guidance does not change the requirements of prior guidance but requires that the noncontrolling interest be reported as a separate component of equity on our condensed consolidated statements of financial position.

Additionally, prior to adoption of the guidance, we recorded our earnings allocated to Piedmont as a component of earnings before income taxes in our condensed consolidated statements of income. The additional guidance requires that any net income attributable to the noncontrolling interest be presented separately in our condensed consolidated statements of income. As a result, net income from noncontrolling interest is reported after net income in order to report net income attributable to the parent and the noncontrolling interest. The adoption of this guidance had no effect on our calculation of basic or diluted earnings per share amounts, which will continue to be based upon amounts attributable to AGL Resources.

Glossary of Key Terms

Note 6 - Debt

Our issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by, or filings with, state and federal regulatory bodies, including state public service commissions, the SEC and the FERC pursuant to the Energy Policy Act of 2005. The following table shows the carrying amounts of our long-term debt included in our condensed consolidated statements of financial position. We estimate the fair value using a discounted cash flow technique that incorporates a market interest yield curve with adjustments for duration, optionality and risk profile. In determining the market interest yield curve, we considered our currently assigned ratings for unsecured debt of BBB+ by S&P, Baa1 by Moody’s and A- by Fitch. For more information on our debt, see Note 6 in our recast consolidated financial statements and related notes as filed on Form 8-K with the SEC on July 13, 2009, and in our Form 10-K for the year ended December 31, 2008, filed with the SEC on February 5, 2009.

In millions	Year(s) due	Weighted average interest rate (1)	Interest rate (2)	Outstanding as of September 30, 2009	December 31, 2008	September 30, 2008
Short-term debt						
Commercial paper	2009	0.8 %	0.6 %	$ 309	$ 273	$ 198
Capital leases	2009	4.9	4.9	1	1	1
Credit Facility	-	-	-	-	500	485
SouthStar line of credit	-	-	-	-	75	55
Sequent lines of credit (3)	-	-	-	-	17	20
Pivotal Utility line of credit (3)	-	-	-	-	-	10
Total short-term debt		0.9 %	0.6 %	$ 310	$ 866	$ 769
Long-term debt - net of current portion						
Senior notes	2011-2034	5.9 %	4.5-7.1 %	$ 1,575	$ 1,275	$ 1,275
Gas facility revenue bonds	2022-2033	1.2	0.2-5.3	200	200	200
Medium-term notes	2012-2027	7.8	6.6-9.1	196	196	196
Capital leases	2013	4.9	4.9	4	4	4
Total long-term debt (4)		5.5 %	5.5 %	$ 1,975	$ 1,675	$ 1,675
Total debt		4.6 %	4.8 %	$ 2,285	$ 2,541	$ 2,444

(1) For the nine months ended September 30, 2009.

(2) As of September 30, 2009.

(3) Sequent’s $25 million line of credit expired in June 2009. Pivotal Utility’s $15 million line of credit expired in October 2008.

(4) Our estimated fair value was $2,116 million as of September 30, 2009, $1,647 million as of December 31, 2008 and $1,671 million as of September 30, 2008.

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

Default Events

Our Credit Facility financial covenants require us to maintain a ratio of total debt to total capitalization of no greater than 70%; however, our goal is to maintain this ratio at levels between 50% and 60%. Our ratio of total debt to total capitalization calculation contained in our debt covenant includes standby letters of credit, surety bonds and the exclusion of other comprehensive income pension adjustments. Adjusting for these items, our debt-to-equity calculation, as defined by our Credit Facility, was 55% at September 30, 2009, 59% at December 31, 2008 and 58% at September 30, 2008. These amounts are within our required and targeted ranges. Our debt-to-equity calculation, as calculated from our condensed consolidated statements of financial position, was 57% at September 30, 2009, 60% at December 31, 2008 and 58% at September 30, 2008.

Our debt instruments and other financial obligations include provisions that, if not complied with, could require early payment, additional collateral support or similar actions. Our most important default events include:

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

We 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. We are currently in compliance with all existing debt provisions and covenants.

Glossary of Key Terms

Note 7 - Commitments and Contingencies

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 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. As we do for other subsidiaries, we provide guarantees to certain gas suppliers for SouthStar in support of payment obligations. There were no significant changes to our contractual obligations described in Note 7 to our recast consolidated financial statements and related notes as filed on Form 8-K with the SEC on July 13, 2009, and in our Form 10-K for the year ended December 31, 2008, filed with the SEC on February 5, 2009.

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. The following table illustrates our contingent financial commitments as of September 30, 2009.

		Commitments due before December 31,	
In millions	Total	2009	2010 & thereafter
Standby letters of credit and performance and surety bonds	$ 26	$ 9	$ 17

Litigation

We are involved in litigation arising in the normal course of business. The ultimate resolution of such litigation is not expected to have a material adverse effect on our condensed consolidated financial position, results of operations or cash flows.

Information on the Jefferson Island Storage & Hub, LLC vs. State of Louisiana litigation is described in Note 7 to our recast consolidated financial statements and related notes as filed on Form 8-K with the SEC on July 13, 2009, and in our Form 10-K for the year ended December 31, 2008, filed with the SEC on February 5, 2009. In April 2009, the trial court ruled that the legislation that restricted Jefferson Island’s ability to use water from the Chicot aquifer to expand its existing storage facility is unconstitutional and invalid.

In August 2009, Jefferson Island announced that it had negotiated a tentative agreement with the state of Louisiana that, subject to approval, would resolve the pending lawsuit between the parties over a disputed mineral lease. A finalized agreement will enable Jefferson Island to resume its plan to expand the existing natural gas storage facility. The state Mineral Board must approve the agreement in order for it to be valid, and a decision could come during the fourth quarter of 2009. The parties also jointly requested that the trial court delay the previously scheduled September 2009 trial date which would have resolved Jefferson Island’s claim that it is authorized to expand the facility under its mineral lease while the parties work through this approval process. The ultimate resolution cannot be determined, but it is not expected to have a material adverse effect on our condensed consolidated financial position, results of operations or cash flows.

In February 2008, the consumer affairs staff of the Georgia Commission alleged that GNG charged its customers on variable rate plans prices for natural gas that were in excess of the published price, that it failed to give proper notice regarding the availability of potentially lower price plans and that it changed its methodology for computing variable rates. GNG asserted that it fully complied with all applicable rules and regulations, that it properly charged its customers on variable rate plans the rates on file with the Georgia Commission, and that, consistent with its terms and conditions of service, it routinely switched customers who requested to move to another price plan for which they qualified. In order to resolve this matter GNG agreed to pay approximately $3 million in the form of credits to customers, or as directed by the Georgia Commission, which was recorded in our statements of consolidated income for the year ended December 31, 2008.

In February 2008, a class action lawsuit was filed in the Superior Court of Fulton County in the State of Georgia against GNG containing similar allegations to those asserted by the Georgia Commission staff and seeking damages on behalf of a class of GNG customers. This lawsuit was dismissed in September 2008. 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, GNG 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. If the Court of Appeals’ decision is not reversed, the parties will proceed with the litigation at the trial court.

In March 2008, a second class action suit was filed against GNG in the State Court of Fulton County in the State of Georgia, regarding monthly service charges. This lawsuit alleges that GNG arbitrarily assigned customer service charges rather than basing each customer service charge on a specific credit score. GNG asserts that no violation of law or Georgia Commission rules has occurred, that this lawsuit is without merit and has filed motions to dismiss this class action suit on various grounds. This lawsuit was dismissed with prejudice in March 2009. In April 2009, the plaintiffs appealed the decision but in June 2009, the plaintiffs withdrew their appeal of the courts dismissal order in exchange for GNG withdrawing and dropping all claims for attorney’s fees and costs in connection with the trial and appellate proceedings.

In March 2009, Piedmont filed a lawsuit in the Court of Chancery of the State of Delaware against us asking the court to enter a judgment declaring that our right to purchase Piedmont’s ownership interest in SouthStar expires on November 1, 2009. We reached a settlement agreement with Piedmont that dismissed the lawsuit and will result in a restructuring of the ownership interests in the SouthStar joint venture. Under the terms of the agreement, which has been approved by the boards of directors of both companies, we will purchase an additional 15% ownership share in the joint venture from Piedmont for $58 million. As a result, we will own 85% of the SouthStar joint venture, and will be entitled to 85% of the annual earnings from the business, while Piedmont will retain the remaining 15% share. As part of the agreement, our interest will remain a noncontrolling interest and we will not have any further option rights to Piedmont’s remaining 15% ownership interest. The effective date of the transaction will be January 1, 2010. The agreement was approved by the Georgia Commission in October 2009.

In May 2009, Pivotal Utility Holdings Inc., through its operating entity Elizabethtown Gas, was served as a responsible party, along with several hundred other entities, in litigation associated with the investigation and cleanup of the Passaic River and Newark Bay in New Jersey. The Plaintiffs, Maxus Energy Corporation and Tierra Solutions, Inc., who are among parties who have been ordered to address contamination in those water bodies, assert that historical operations of Elizabethtown Gas' former manufactured gas plants contributed to contamination at issue. We have not evaluated Plaintiffs' claims but do not believe that Elizabethtown Gas' historical operations would have had any significant impact in either the Passaic River or Newark Bay. At the present time, we cannot estimate the amount of any loss, if any, associated with this claim. In addition, we believe that any amounts associated with this claim would be subject to Elizabethtown Gas’ remediation adjustment clause that allows it to recover through the rate mechanism, subject to stated limitations, costs associated with environmental remediation cost investigation and cleanup.

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. For more information on our environmental remediation costs, see Note 7 in our recast consolidated financial statements and related notes as filed on Form 8-K with the SEC on July 13, 2009, and in our Form 10-K for the year ended December 31, 2008, filed with the SEC on February 5, 2009.The following table provides more information on our former operating sites:

In millions	Cost estimate range	Amount recorded	Expected costs over next twelve months
	$	$ 53	$ 10

Georgia and Florida		53 - 98				
New Jersey		65 - 110		65		9
North Carolina		12 - 21		12		2
Total	$	130 - 229	$	130	$	21

We have identified 13 former operating sites in Georgia and Florida where Atlanta Gas Light owned or operated all or part of these sites. As of December 31, 2008, the soil and sediment remediation program was complete for all Georgia sites, although groundwater cleanup continues. For elements of the program where we still cannot provide engineering cost estimates, considerable variability remains in future cost estimates.

Additionally, 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.

Review of Compliance with FERC Regulations

In 2008 we conducted an internal review of our compliance with FERC interstate natural gas pipeline capacity release rules and regulations. Independent of our internal review, we also received data requests from FERC's Office of Enforcement relating specifically to compliance with the FERC's capacity release posting and bidding requirements. In June 2009, we reached a settlement agreement with the FERC. This settlement agreement did not have a material financial impact to our condensed consolidated results of operations, cash flows or financial position.

Glossary of Key Terms

Table of Contents

Note 8 - Segment Information

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

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

You should not consider EBIT an alternative to, or a more meaningful indicator of, our operating performance than operating income or net income attributable to AGL Resources Inc. as determined in accordance with GAAP. In addition, our EBIT may not be comparable to a similarly titled measure of another company. The following table contains the reconciliations of EBIT to operating income, earnings before income taxes and net income attributable to AGL Resources Inc. for the three and nine months ended September 30, 2009 and 2008.

	Three months ended September 30,	
In millions	2009	2008
Operating revenues	$ 307	$ 539
Operating expenses	264	413
Operating income	43	126
Other income	2	2
EBIT	45	128
Interest expense, net	(26)	(29)
Earnings before income taxes	19	99
Income tax expense	7	39
Net income	12	60
Net loss attributable to the noncontrolling interest	-	(5)
Net income attributable to AGL Resources Inc.	$ 12	$ 65

Nine months ended
September 30,

In millions	2009	2008
Operating revenues	$ 1,679	$ 1,995
Operating expenses	1,351	1,675
Operating income	328	320
Other income	7	6
EBIT	335	326
Interest expense, net	(75)	(85)
Earnings before income taxes	260	241
Income tax expense	92	86
Net income	168	155
Net income attributable to the noncontrolling interest	17	12
Net income attributable to AGL Resources Inc.	$ 151	$ 143

Glossary of Key Terms

Information by segment on our statement of financial position at December 31, 2008, is as follows:

In millions	Identifiable and total assets (1)	Goodwill
Distribution operations	$ 5,138	$ 404
Retail energy operations	315	-
Wholesale services	970	-
Energy investments	353	14
Corporate and intercompany eliminations (2)	(66)	-
Consolidated AGL Resources Inc.	$ 6,710	$ 418

(1) Identifiable assets are those assets used in each segment's operations.

(2) Our corporate segment's assets consist primarily of cash and cash equivalents and property, plant and equipment and reflect the effect of intercompany eliminations.

Summarized income statement information, identifiable and total assets, goodwill and property, plant and equipment expenditures as of and for the three and nine months ended September 30, 2009 and 2008, by segment, are shown in the following tables.

Three months ended September 30, 2009

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intercompany eliminations (3)	Consolidated AGL Resources
Operating revenues from external parties	$ 184	$ 100	$ 10	$ 11	$ 2	$ 307
Intercompany revenues (1)	35	-	-	-	(35)	-
Total operating revenues	219	100	10	11	(33)	307
Operating expenses						
Cost of gas	46	86	-	-	(33)	99
Operation and maintenance	84	15	12	5	(1)	115
Depreciation and amortization	34	1	-	3	2	40
Taxes other than income taxes	9	-	-	-	1	10
Total operating expenses	173	102	12	8	(31)	264
Operating income (loss)	46	(2)	(2)	3	(2)	43
Other income	2	-	-	-	-	2
EBIT	$ 48	$ (2)	$ (2)	$ 3	$ (2)	$ 45
	$ 73	$ -	$ -	$ 32	$ 2	$ 107

Capital expenditures for property, plant and equipment

Three months ended September 30, 2008

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intercompany eliminations (3)	Consolidated AGL Resources
Operating revenues from external parties	$ 237	$ 149	$ 138	$ 13	$ 2	$ 539
Intercompany revenues (1)	35	-	-	-	(35)	-
Total operating revenues	272	149	138	13	(33)	539
Operating expenses						
Cost of gas	101	154	37	3	(34)	261
Operation and maintenance	72	15	13	6	(2)	104
Depreciation and amortization	32	1	1	1	3	38
Taxes other than income taxes	9	-	1	-	-	10
Total operating expenses	214	170	52	10	(33)	413
Operating income (loss)	58	(21)	86	3	-	126
Other income	1	-	-	-	1	2
EBIT	$ 59	$ (21)	$ 86	$ 3	$ 1	$ 128
Capital expenditures for property, plant and equipment	$ 62	$ -	$ -	$ 23	$ 3	$ 88

Glossary of Key Terms

Table of Contents

Nine months ended September 30, 2009

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intercompany eliminations (3)	Consolidated AGL Resources
Operating revenues from external parties	$ 996	$ 568	$ 80	$ 31	$ 4	$ 1,679
Intercompany revenues (1)	105	-	-	-	(105)	-
Total operating revenues	1,101	568	80	31	(101)	1,679
Operating expenses						
Cost of gas	486	447	9	-	(102)	840
Operation and maintenance	255	51	42	17	(6)	359
Depreciation and amortization	99	3	2	6	8	118
Taxes other than income taxes	27	1	2	1	3	34
Total operating expenses	867	502	55	24	(97)	1,351
Operating income (loss)	234	66	25	7	(4)	328
Other income	7	-	-	-	-	7
EBIT	$ 241	$ 66	$ 25	$ 7	$ (4)	$ 335
Identifiable and total assets (2)	$ 4,996	$ 182	$ 651	$ 415	$ (61)	$ 6,183
Goodwill	$ 404	$ -	$ -	$ 14	$ -	$ 418
Capital expenditures for property, plant and equipment	$ 231	$ 1	$ -	$ 72	$ 10	$ 314

Nine months ended September 30, 2008

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intercompany eliminations (3)	Consolidated AGL Resources
Operating revenues from external parties	$ 1,146	$ 701	$ 104	$ 43	$ 1	$ 1,995
Intercompany revenues (1)	147	-	-	-	(147)	-
Total operating revenues	1,293	701	104	43	(146)	1,995
Operating expenses						
Cost of gas	694	600	41	4	(146)	1,193
Operation and maintenance	241	50	35	16	(5)	337
Depreciation and amortization	94	3	4	4	7	112
Taxes other than income taxes	27	1	2	1	2	33
Total operating expenses	1,056	654	82	25	(142)	1,675
Operating income (loss)	237	47	22	18	(4)	320
Other income	2	-	-	-	4	6
EBIT	$ 239	$ 47	$ 22	$ 18	$ -	$ 326
Identifiable and total assets (2)	$ 4,992	$ 271	$ 1,007	$ 322	$ (88)	$ 6,504
Goodwill	$ 404	$ -	$ -	$ 14	$ -	$ 418
Capital expenditures for property, plant and equipment	$ 196	$ 7	$ -	$ 44	$ 7	$ 254

(1) Intercompany revenues – wholesale services records its energy marketing and risk management revenues on a net basis, which includes intercompany revenues of $75 million and $289 million for the three months ended September 30, 2009 and 2008, respectively; and $332 million and $806 million for the nine months ended September 30, 2009 and 2008, respectively.

(2) Identifiable assets are those used in each segment's operations.

(3) Our corporate segment's assets consist primarily of cash and cash equivalents, property, plant and equipment and reflect the effect of intercompany eliminations.

Glossary of Key Terms

ITEM 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations

FORWARD-LOOKING STATEMENTS

Certain expectations and projections regarding our future performance referenced in this Management’s Discussion and Analysis of Financial Condition and Results of Operations section and elsewhere in this report, as well as in other reports and proxy statements we file with the SEC or otherwise release to the public and on our website are forward-looking statements. 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,” "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 several factors - many beyond our control - that could cause our results to differ 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.

We caution readers that, in addition to the important factors described elsewhere in this report, the factors set forth in Item 1A, “Risk Factors” of our Annual Report on Form 10-K for the year ended December 31, 2008, among others, could cause our business, results of operations or financial condition in 2009 and thereafter 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 our Form 10-K or 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 do not update these statements to reflect subsequent circumstances or events.

Overview

We are an energy services holding company whose principal business is the distribution of natural gas through our regulated natural gas distribution business and the sale of natural gas to end-use customers primarily in Georgia through our retail natural gas marketing business. As of September 30, 2009, our six utilities serve approximately 2.3

million end-use customers, making us the largest distributor of natural gas in the southeastern and mid-Atlantic regions of the United States based on customer count. Although our retail natural gas marketing business is not subject to the same regulatory framework as our utilities, it is an integral part of the framework for providing natural gas service to end-use customers in Georgia.

We also engage in natural gas asset management and related logistics activities for our own utilities as well as for non-affiliated companies; natural gas storage arbitrage and related activities; and the development and operation of high-deliverability underground natural gas storage assets. These businesses allow us to be opportunistic in capturing incremental value at the wholesale level, provide us with deepened business insight about natural gas market dynamics and facilitate our ability, in the case of asset management, to provide transparency to regulators as to how that value can be captured to benefit our utility customers through profit-sharing arrangements. Given the volatile and changing nature of the natural gas resource base in North America and globally, we believe that participation in these related businesses strengthens our company. We manage these businesses through four operating segments - distribution operations, retail energy operations, wholesale services, energy investments and a non-operating corporate segment.

Executive Summary

We intend to continue executing our plan for long-term earnings and dividend growth. Central to that plan is the execution of our regulatory planning through the filing of rate cases and other regulatory requests to recover the investments we have made, and should continue to make, to enhance our infrastructure and improve customer service. Further, we are collaborating with regulatory agencies and other companies to promote and encourage conservation through innovative rate design mechanisms that we believe are positioning our utility businesses to benefit in an economic recovery.

Glossary of Key Terms

We continue to explore select opportunities to expand our businesses in strategic areas and maintain a disciplined approach around current capital projects. Our major capital projects - our Golden Triangle Storage natural gas storage facility project and our Hampton Roads Crossing and Magnolia pipeline connection projects - are expected to be completed by year-end and be within budget. In these challenging economic conditions, we continue to aggressively focus on capital discipline and cost control, while moving ahead with projects and initiatives that we expect to have current and future benefits and provide an appropriate return on capital.

During the last half of 2008 and continuing into 2009, natural gas prices declined significantly, reflecting the decline in the United States economy, increasing natural gas supplies and above-average storage volumes, among other factors. These lower gas prices resulted in significantly lower levels of working capital necessary for our operating segments to purchase their natural gas inventories as compared to recent inventory injection seasons. We may experience increased pressure on our working capital requirements and borrowing capacity under our existing Credit Facility should natural gas prices return to levels experienced in 2008.

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

Each utility operates subject to regulations of the state regulatory agencies in its service territories with respect to rates charged to our customers, maintenance of accounting records and various other service and safety matters. Rates charged to our customers vary according to customer class (residential, commercial or industrial) and rate jurisdiction. Rates are set at levels that generally should allow us 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.

Customer growth declined slightly in our distribution operations segment in the first nine months of 2009 relative to last year, a trend we expect to continue through the end of 2009. For the nine months ended September 30, 2009, our year-over-year consolidated utility customer growth rate was slightly negative or (0.3)%, compared to 0.1% positive growth for the same period of 2008. We anticipate overall customer growth in 2009 to be flat to negative, primarily as a result of much slower growth in the residential housing markets throughout most of our service territories and the effects of a weak economy on our commercial and industrial customers. As compared to 3 years ago, we have reduced our customer attrition rates. As a result, we believe we should be well positioned when the economy recovers.

The weak economy is expected to continue to impact a significantly larger portion of consumer household incomes during the upcoming winter heating season. However, natural gas prices and the WACOG of our natural gas inventories have declined significantly since last year, which is expected will result in lower average customer bills and no significant increases in our bad debt expenses.

We work with regulators and state agencies in each of our jurisdictions to educate customers about energy costs in advance of the winter heating season, in particular, 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.

Distribution Operations - regulatory planning

In 2010 and 2011, we expect to file base rate cases in three of our six jurisdictions. Over the past several years our utilities have been fulfilling their long-term commitments to rate freezes, which began expiring in 2009. These rate case filings are required due to settlements we reached with the applicable state authority in previous rate case or acquisition proceedings. The expected filing dates and dates for which current rates are expected to be effective are outlined in the chart below:

Company	Expected filing date (2)	Current rates effective until
Atlanta Gas Light (1)	Q2 2010	Q4 2010
Chattanooga Gas	Q2 2010	Q1 2011
Virginia Natural Gas	Q1 2011	Q3 2011

(1) In July 2009, Atlanta Gas Light filed a request with the Georgia Commission to postpone its scheduled filing of a rate case in November 2009.This request was approved by the Georgia Commission which agreed to postpone the filing until April 1, 2010, but no later than June 1, 2010.

(2) Subject to change.

Glossary of Key Terms

Table of Contents

Elizabethtown Gas After a 5-year rate freeze and in accordance with the New Jersey BPU's order, we filed a rate case in March 2009 with a proposed effective date of January 1, 2010. Our initial request was an annual increase to base rates of $25 million. The filing also included energy conservation programs and a proposed Efficiency Usage and Adjustment mechanism (EUA), which is a form of decoupling, including weather normalization. In traditional rate designs, our utilities' recovery of a significant portion of their fixed customer service costs is tied to assumed natural gas volumes used by our customers. We believe separating, or decoupling, the recovery of these fixed costs from the natural gas deliveries will align the interests of our customers and utilities by encouraging energy conservation, achieving rate stability for our customers and ensuring stable returns for our shareholders. If the EUA is approved, the current weather normalization clause would be suspended.

In June 2009, and in accordance with New Jersey rate case rules that require the filing of quarterly updates to a case, we filed a revised request for a $17 million annual increase to base rates. The primary driver of the reduced request was a revision to our depreciation rates.

In August 2009, the New Jersey Department of the Public Counsel, Division of Rate Counsel (Rate Counsel) filed testimony recommending a base rate decrease of $13 million. We are currently in settlement discussions with the Rate Counsel and the New Jersey BPU's staff, and we expect all parties to come to an acceptable agreement that will be considered by the New Jersey BPU before the end of 2009.

Distribution Operations - capital projects

In June 2009, Atlanta Gas Light filed a request for a Strategic Infrastructure Development and Enhancement (STRIDE) program with the Georgia Commission to upgrade its distribution system and liquefied natural gas facilities to improve system reliability and create a platform to meet operational flexibility needs and forecasted growth. Under the program, Atlanta Gas Light would be required to file a ten-year infrastructure plan every three years for review and approval by the Georgia Commission. The program merges with Atlanta Gas Light's existing Pipeline Replacement Program (PRP), which was initiated in 1998 and is scheduled to end in December 2013.

In October 2009, the Georgia Commission approved the initial three years of the STRIDE program, estimated at approximately $176 million, which will increase the existing $1.95 monthly PRP charge for Atlanta Gas Light's customers by $0.39 beginning in October 2009. Beginning October 2010, the rates will increase by an additional $0.39 for a total of $0.78 per month, and beginning in October 2011, the rates will increase by an additional $0.40 per month for a total of $1.18 per month. The increased charges are subject to review and modification by the Georgia Commission every three years. Further, in October 2009 and subsequent to the Georgia Commission's approval of the STRIDE program, an organization representing members in Georgia has filed a Motion for Reconsideration of the order approving the program with the Georgia Commission, as well as an appeal to the State Superior Court for a review of the Georgia Commission's ruling that the organization did not have discovery rights in the STRIDE program proceeding. Pursuant to the Georgia Commission's approval order, neither of these filings prevents the STRIDE program from going into effect. We cannot predict what action, if any, the Georgia Commission or the State Superior Court will take in response to these filings. For more information on Atlanta Gas Light's PRP program, see Note 1 in our recast consolidated financial statements and related notes as filed on Form 8-K with the SEC on July 13, 2009, and in our Form 10-K for the year ended December 31, 2008, filed with the SEC on February 5, 2009.

In April 2009, the New Jersey BPU approved an accelerated $60 million enhanced infrastructure program for Elizabethtown Gas which started this year and is scheduled to be completed in 2011. This program was created in response to the New Jersey Governor's request for utilities to assist in the economic recovery by increasing infrastructure investments. A regulatory cost recovery mechanism will be established with estimated rates put into effect at the beginning of each year. At the end of the program the regulatory cost recovery mechanism will be trued-up and any remaining costs not previously collected will be included in base rates. Elizabethtown Gas expects that approximately $18 million in capital expenditures for this program will occur in 2009.

Retail Energy Operations

Our retail energy operations segment consists of SouthStar, a joint venture currently owned 70% by us and 30% by Piedmont. SouthStar markets natural gas and related services to retail customers on an unregulated basis, principally in Georgia, as well as to commercial and industrial customers in Alabama, Florida, Ohio, Tennessee, North Carolina and South Carolina. SouthStar is the largest marketer of natural gas in Georgia with an approximate 33% market share based on customer count.

Although our ownership interest in the SouthStar partnership is currently 70%, the majority of SouthStar's earnings in Georgia are currently allocated, by contract, 75% to us and 25% to Piedmont. SouthStar’s earnings related to customers in Ohio and Florida are currently allocated 70% to us and 30% to Piedmont. We record the earnings allocated to Piedmont as a noncontrolling interest in our condensed consolidated statements of income, and we record Piedmont’s portion of SouthStar’s capital as a noncontrolling interest in our condensed consolidated statements of financial position. The majority of SouthStar’s earnings allocated to us for the nine months ended September 30, 2009, were largely at the 75% contractual rate.

Glossary of Key Terms

In March 2009, Piedmont filed a lawsuit in the Court of Chancery of the State of Delaware against us asking the court to enter a judgment declaring that our right to purchase Piedmont's ownership interest in SouthStar expires on November 1, 2009. We reached a settlement agreement with Piedmont that dismissed the lawsuit and will result in a restructuring of the ownership interests in the SouthStar joint venture. Under the terms of the agreement, which has been approved by the boards of directors of both companies, we will purchase an additional 15% ownership share in the joint venture from Piedmont for $58 million. As a result, we will own 85% of the SouthStar joint venture, and will be entitled to 85% of the annual earnings from the business, while Piedmont will retain the remaining 15% share. As part of the agreement, our interest will remain a noncontrolling interest and we will not have any further option rights to Piedmont's remaining 15% ownership interest. The agreement was approved by the Georgia Commission in October 2009 and the effective date of the transaction will be January 1, 2010.

SouthStar's operations are sensitive to seasonal weather, natural gas prices, retail pricing plans and strategies, customer growth and consumption patterns similar to those affecting our utility operations. SouthStar's retail pricing strategies and use of various economic hedging strategies, such as 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 on its operations.

In the Georgia market, SouthStar continues to experience the negative impact to operating margins from increased competition and an increase in the number of customers shopping for lower retail natural gas prices. Further, the number of customers switching Marketers in the Georgia market has increased in part due to customers seeking the most competitive price plans.

SouthStar continues to use a variety of targeted marketing programs to attract new customers and to retain existing ones. Despite these efforts we have seen a 4% decline in average customer count for the nine months ended September 30, 2009, as compared to the same period of 2008. We believe this decline reflects some of the same economic conditions that have affected our utility businesses as well as the more competitive retail pricing market for natural gas in Georgia.

SouthStar may also be affected by the conservation and bad debt trends, but its overall exposure is partially mitigated by the high credit quality of SouthStar's customer base, lower wholesale natural gas prices in 2009, disciplined collection practices and the unregulated pricing structure in Georgia.

SouthStar continues to expand its business in other states as well. We are currently focusing these efforts on the Ohio and Florida markets.

Wholesale Services

Our wholesale services segment consists primarily of Sequent, our subsidiary involved in asset management and optimization, storage, transportation, producer and peaking services and wholesale marketing. Sequent seeks asset optimization opportunities, which focus on capturing the value from idle or underutilized assets, typically by participating in transactions to take advantage of pricing differences between varying markets and time horizons within the natural gas supply, storage and transportation markets to generate earnings. These activities are generally referred to as arbitrage opportunities.

Sequent's profitability is driven by volatility in the natural gas marketplace. Volatility arises from a number of factors such as weather fluctuations or the change in supply of, or demand for, natural gas in different regions of the United States. Sequent seeks to capture value from the price disparity across geographic locations and various time horizons (location and seasonal spreads). In doing so, Sequent also seeks to mitigate the risks associated with this volatility and protect its margin through a variety of risk management and economic hedging activities.

Sequent provides its customers with natural gas from the major producing regions and market hubs in the United States and Canada. Sequent acquires transportation and storage capacity to meet its delivery requirements and customer obligations in the marketplace. Sequent’s customers benefit from its logistics expertise and ability to deliver natural gas at prices that are advantageous relative to other alternatives available to its customers.

During the third quarter of 2008, Sequent negotiated an agreement for 0.04 Bcf per day of transportation capacity for a period of 25 years beginning in August 2009. This agreement was executed in April 2009, and as a result, we have included approximately $89 million of future demand payments associated with this capacity within our unrecorded contractual obligations and commitment disclosures. As with its other transportation capacity agreements, Sequent has and will identify opportunities to lock-in economic value associated with this capacity through the use of financial hedges. Since the duration of this agreement is significantly longer than the average duration of Sequent’s portfolio, the hedging of the capacity has increased our exposure to hedge gains and losses as well as impacting Sequent’s VaR.

During the second half of 2008, we began executing hedging transactions related to this transportation capacity. As a result of changes in the fair value of these hedges, Sequent reported no hedge gains during the three months ending September 30, 2009 and $22 million during the nine months ending September 30, 2009. There was no significant impact to VaR during these periods. For transportation-related hedge gains or losses, no corresponding loss or gain is recognized on the hedged transportation transactions since the underlying transportation contracts are not recorded at fair value. The gains or losses on the transportation agreements would be recognized in the period they are realized, which is the period the transportation capacity is available for our use.

Glossary of Key Terms

Table of Contents

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

The following table provides updated information on Sequent's asset management agreements with its affiliated utilities, including amended or extended agreements in 2008 and 2009 with Florida City Gas, Chattanooga Gas, Elizabethtown Gas and Virginia Natural Gas.

	Expiration date	% of shared profits or annual fee
Chattanooga Gas	March 2011	50% (A)
Elizabethtown Gas	March 2011	(A) (B)
Atlanta Gas Light	March 2012	up to 60% (A)
Virginia Natural Gas	March 2012	(A) (B)
Florida City Gas	March 2013	50%

(A) Includes aggregate annual minimum payments of $14 million for Atlanta Gas Light, Chattanooga Gas, Elizabethtown Gas and Virginia Natural Gas.

(B) Shared on a tiered structure.

Storage inventory outlook The following graph presents the NYMEX forward natural gas prices as of September 30, 2009, June 30, 2009 and December 31, 2008, for the period of October 2009 through September 2010, and reflects the prices at which Sequent could buy natural gas at the Henry Hub for delivery in the same time period. The Henry Hub is the largest centralized point for natural gas spot and futures trading in the United States. The NYMEX uses the Henry Hub as the point of delivery for its natural gas futures contracts. Many natural gas marketers also use the Henry Hub as their physical contract delivery point or their price benchmark for spot trades of natural gas.

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 regulatory sharing and reflect the amounts that are realizable in future periods based on its inventory withdrawal schedule and forward natural gas prices at September 30, 2009. Sequent's storage inventory is economically hedged with futures contracts, which results in an overall locked-in margin, timing notwithstanding.

	Withdrawal schedule (in Bcf)		
	Salt dome (WACOG $3.48)	Reservoir (WACOG $3.36)	Expected operating revenues (in millions)

2009			
Fourth quarter	3	11	$ 23
2010			
First quarter	-	10	18
Second quarter	-	1	3
Third quarter	-	1	1
Total	3	23	$ 45

If Sequent's storage withdrawals associated with existing inventory positions are executed as planned, it expects operating revenues from storage withdrawals of approximately $45 million during the next twelve months. This could 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. Based upon Sequent's current projection of year-end storage positions at December 31, 2009, a $1.00 increase in the first quarter 2010 forward NYMEX prices could result in a $9 million reduction to Sequent's reported operating revenues for the year ending December 31, 2009, after regulatory sharing. A $1.00 decrease in forward NYMEX prices would result in a $9 million positive impact to Sequent's reported operating revenues; however additional LOCOM adjustments could potentially offset a portion of the positive impact. This amount does not include operating expenses that will be incurred to realize this amount.For more information on Sequent's energy marketing and risk management activities, see Item 3, Quantitative and Qualitative Disclosures About Market Risk - Natural Gas Price Risk.

Glossary of Key Terms

Energy Investments

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

We are actively pursuing a settlement with the State of Louisiana to complete an operating agreement allowing Jefferson Island to expand its existing facility. In August 2009, Jefferson Island announced that it had negotiated a tentative agreement with the state of Louisiana that, subject to approval, would resolve the pending lawsuit between the parties over a disputed mineral lease. A finalized agreement will enable Jefferson Island to resume its plan to expand the existing natural gas storage facility. The state Mineral Board must approve the agreement in order for it to be valid, and a decision could come within the fourth quarter of 2009. The parties also jointly requested that the trial court delay the previously scheduled September 2009 trial date which would have resolved Jefferson Island's claim that it is authorized to expand the facility under its mineral lease while the parties work through this approval process. The ultimate resolution cannot be determined, but it is not expected to have a material adverse effect on our consolidated financial condition, results of operations or cash flows.

Jefferson Island's litigation with the State of Louisiana is described in further detail in Note 7 in our recast consolidated financial statements and related notes as filed on Form 8-K with the SEC on July 13, 2009, and in our Form 10-K for the year ended December 31, 2008, filed with the SEC on February 5, 2009.

Our Golden Triangle Storage project will consist of a new salt-dome storage facility in the Gulf Coast region of the U.S. with 12 Bcf of working natural gas capacity and total cavern capacity of 18 Bcf. In May 2008, Golden Triangle Storage started construction on both caverns. We expect the first cavern with 6 Bcf of working capacity to be in service in the third or fourth quarter of 2010 and the second cavern with 6 Bcf of working capacity to be in service in mid 2012.

We previously estimated, based on then current prices for labor, materials and pad gas that costs to construct the two caverns would be approximately $265 million. However, prices for labor and materials have risen significantly in the ensuing months, increasing the estimated construction cost by approximately 18% to $314 million. 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 70% of these items have been fixed and are not subject to continued variability during the construction period. Further, since we are not able to predict whether these costs of construction will continue to increase, moderate or decrease from current levels, we believe that there could be continued volatility in the construction cost estimates.

We also own and operate a telecommunications business, AGL Networks, which constructs and operates conduit and fiber infrastructure within select metropolitan areas in the United States.

Corporate

Our corporate segment includes our nonoperating business units, including AGL Services Company and AGL Capital. We allocate substantially all of our corporate segment's operating expenses and interest costs to our operating segments in accordance with state regulations. Our corporate segment results include the impact of these allocations to the various operating segments. Our corporate segment also includes intercompany eliminations for transactions between our operating segments.

Results of Operations

Operating margin and EBIT We evaluate segment performance using the measures of operating margin and EBIT, which include the effects of corporate expense allocations. Our operating margin and EBIT are not measures that are considered to be calculated in accordance with GAAP. Operating margin is a non-GAAP measure that is calculated as operating revenues minus cost of gas, which excludes operation and maintenance expense, depreciation and amortization, taxes other than income taxes, and the gain or loss on the sale of our assets; these items are included in our calculation of operating income as reflected in our condensed consolidated statements of income. EBIT is also a non-GAAP measure that includes operating income, other income and expenses. Items that we do not include in EBIT are financing costs, including interest and debt expense and income taxes, each of which we evaluate on a consolidated level.

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

You should not consider operating margin or EBIT an alternative to, or a more meaningful indicator of, our operating performance than operating income, or net income attributable to AGL Resources Inc. as determined in accordance with GAAP. In addition, our operating margin or EBIT measures may not be comparable to similarly titled measures from other companies.

Glossary of Key Terms

Table of Contents

Income taxes As a result of our adoption of new authoritative guidance related to consolidations, income tax expense and our effective tax rate are determined from earnings before income tax less net income (loss) attributable to the noncontrolling interest. For more information on our adoption of this guidance, see Note 5.

Seasonality The operating revenues and EBIT of our distribution operations, retail energy operations and wholesale services segments are seasonal. During the heating season, natural gas usage and operating revenues are generally higher because more customers are connected to our distribution systems and natural gas usage is higher in periods of colder weather than in periods of warmer weather. Occasionally in the summer, Sequent's operating margins are impacted due to peak usage by power generators in response to summer energy demands. Our base operating expenses, excluding cost of gas, interest expense and certain incentive compensation costs, are incurred relatively equally over any given year. Thus, our operating results vary significantly from quarter to quarter as a result of seasonality.

Seasonality also affects the comparison of certain statement of financial position items, such as receivables, inventories and short-term debt across quarters. However, these items are comparable when reviewing our annual results. Accordingly, we have presented the condensed consolidated statement of financial position as of September 30, 2008, to provide comparisons of these items to December 31, 2008, and September 30, 2009.

Hedging Changes in natural gas prices subject a significant portion of our operations to earnings variability. Our nonutility businesses principally use physical and financial arrangements economically to hedge the risks associated with seasonal fluctuations in market conditions, changing natural gas prices and weather. In addition, because these economic hedges may not qualify, or are not designated, for hedge accounting treatment, our reported earnings for the wholesale services and retail energy operations segments include the changes in the fair values of certain financial derivatives. These values may change significantly from period to period and are reflected as fair value adjustments within our operating margin.

Elizabethtown Gas utilizes certain financial derivatives in accordance with a directive from the New Jersey BPU to create a hedging program to hedge the impact of market fluctuations in natural gas prices. These derivative products are accounted for at fair value each reporting period. In accordance with regulatory requirements, realized gains and losses related to these financial derivatives are reflected in deferred natural gas costs and ultimately included in billings to customers. Unrealized gains and losses are reflected as a regulatory asset or liability, as appropriate, in our condensed consolidated statements of financial position.

Glossary of Key Terms

The following table sets forth a reconciliation of our operating margin and EBIT to our operating income, earnings before income taxes and net income attributable to AGL Resources Inc., together with other consolidated financial information for the three and nine months ended September 30, 2009 and 2008.

	Three months ended September 30,			Nine months ended September 30,		
In millions, except per share data	2009	2008	Change	2009	2008	Change
Operating revenues	$ 307	$ 539	$ (232)	$ 1,679	$ 1,995	$ (316)
Cost of gas	99	261	(162)	840	1,193	(353)
Operating margin (1)	208	278	(70)	839	802	37
Operating expenses	165	152	13	511	482	29
Operating income	43	126	(83)	328	320	8
Other income	2	2	-	7	6	1
EBIT (1)	45	128	(83)	335	326	9
Interest expense, net	26	29	(3)	75	85	(10)
Earnings before income taxes	19	99	(80)	260	241	19
Income tax expense	7	39	(32)	92	86	6
Net income	12	60	(48)	168	155	13
Net (loss) income attributable to the noncontrolling interest	-	(5)	(5)	17	12	5
Net income attributable to AGL Resources Inc.	$ 12	$ 65	$ (53)	$ 151	$ 143	$ 8
Earnings per common share						
Basic – attributable to AGL Resources Inc. common shareholders	$ 0.16	$ 0.85	$ (0.69)	$ 1.97	$ 1.87	$ 0.10
Diluted – attributable to AGL Resources Inc. common shareholders	$ 0.16	$ 0.85	$ (0.69)	$ 1.97	$ 1.87	$ 0.10
Weighted-average number of common shares outstanding						
Basic	76.9	76.4	0.5	76.7	76.2	0.5
Diluted	77.2	76.6	0.6	76.9	76.5	0.4

(1) These are non-GAAP measurements.

For the third quarter of 2009, net income attributable to AGL Resources Inc. decreased by $53 million or 82% and earnings per share attributable to AGL Resources Inc. decreased by $0.69 per basic and diluted share compared to the same period last year. The variance was primarily the result of lower operating margins at wholesale services and corporate, offset by higher operating margins at retail energy operations, distribution operations and energy investments. Our operating expenses were higher primarily due to increased pension and postretirement benefit costs, payroll and incentive compensation and depreciation expenses at distribution operations.

For the nine months ended September 30, 2009, net income attributable to AGL Resources Inc. increased by $8 million or 6% and earnings per share attributable to AGL Resources Inc. increased by $0.10 per basic and diluted share compared to the same period last year. The variance was primarily the result of higher operating margins at distribution operations, retail energy operations and wholesale services offset by lower operating margins at energy investments and higher operating expenses at all our segments.

Interest expense for the third quarter of 2009 decreased by $3 million or 10% from the third quarter of 2008, resulting from a decrease in short-term interest rates and lower average debt outstanding. Interest expense for the nine months ended September 30, 2009 decreased by $10 million or 12% from the same period last year, resulting from a decrease in short-term interest rates, partially offset by higher average debt outstanding. More information about our average debt and rates are indicated in the following table.

	Three months ended September 30,			Nine months ended September 30,		
In millions	2009	2008	Change	2009	2008	Change
Average debt outstanding (1)	$ 2,203	$ 2,225	$ (22)	$ 2,156	$ 2,046	$ 110
Average rate	4.7 %	5.2 %	(0.5)%	4.6 %	5.5 %	(0.9)%

(1) Daily average of all outstanding debt.

Glossary of Key Terms

Table of Contents

Selected weather, customer and volume metrics, which we consider to be some of the key performance indicators for our operating segments, for the three and nine months ended September 30, 2009 and 2008, are presented in the following tables. We measure the effects of weather on our business through heating degree days. Generally, increased heating degree days result in greater demand for gas on our distribution systems. However, extended and unusually mild weather during the heating season can have a significant negative impact on demand for natural gas. Our marketing and customer retention initiatives are measured by our customer metrics which can be impacted by natural gas prices, economic conditions and competition from alternative fuels. Volume metrics for distribution operations and retail energy operations present the effects of weather and our customers' demand for natural gas. Wholesale services' daily physical sales represent the daily average natural gas volumes sold to its customers.

Weather

Heating degree days (1)

	Nine months ended September 30,			2009 vs. normal colder (warmer)	2009 vs. 2008 colder (warmer)
	Normal	2009	2008		
Georgia	1,600	1,621	1,654	1 %	(2)%
New Jersey	3,058	3,137	2,918	3 %	8 %
Virginia	2,083	2,247	1,880	8 %	20 %
Florida	349	390	215	12 %	81 %
Tennessee	1,824	1,871	1,888	3 %	(1)%
Maryland	3,052	3,118	2,828	2 %	10 %

(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 2000 through 2009.

Customers	Three months ended September 30,			Nine months ended September 30,		
	2009	2008	% change	2009	2008	% change
Distribution Operations						
Average end-use customers (in thousands)						
Atlanta Gas Light	1,525	1,536	(0.7)%	1,556	1,564	(0.5)%
Elizabethtown Gas	272	272	-	274	273	0.4 %
Virginia Natural Gas	269	268	0.4 %	272	271	0.4 %
Florida City Gas	103	103	-	103	104	(1.0)%
Chattanooga Gas	60	60	-	61	61	-
Elkton Gas	6	6	-	6	6	-
Total	2,235	2,245	(0.4)%	2,272	2,279	(0.3)%
Operation and maintenance expense per customer	$ 38	$ 32	19 %	$ 112	$ 106	6 %
EBIT per customer	$ 21	$ 26	(19)%	$ 106	$ 105	1 %
Retail Energy Operations						
Average customers in Georgia (in	496	518	(4)%	508	529	(4)%

thousands)						
Market share in Georgia	33 %	34 %	(3)%	33 %	35 %	(6)%

Volumes In billion cubic feet (Bcf)	Three months ended September 30,			Nine months ended September 30,		
	2009	2008	% change	2009	2008	% change
Distribution Operations						
Firm	20	20	-	148	147	1 %
Interruptible	23	24	(4)%	72	78	(8)%
Total	43	44	(2)%	220	225	(2)%
Retail Energy Operations						
Georgia firm	3	3	-	26	27	(4)%
Ohio and Florida	1	-	100 %	8	3	167 %
Wholesale Services						
Daily physical sales (Bcf/day)	2.7	2.6	4 %	2.8	2.5	12 %

Glossary of Key Terms

Table of Contents

Three months ended September 30, 2009 compared to three months ended September 30, 2008

Segment information Operating margin, operating expenses and EBIT information for each of our segments are contained in the following table for the three months ended September 30, 2009 and 2008.

In millions	Operating margin (1)	Operating expenses	EBIT (1)
2009			
Distribution operations	$ 173	$ 127	$ 48
Retail energy operations	14	16	(2)
Wholesale services	10	12	(2)
Energy investments	11	8	3
Corporate (2)	-	2	(2)
Consolidated	$ 208	$ 165	$ 45

In millions	Operating margin (1)	Operating expenses	EBIT (1)
2008			
Distribution operations	$ 171	$ 113	$ 59
Retail energy operations	(5)	16	(21)
Wholesale services	101	15	86
Energy investments	10	7	3
Corporate (2)	1	1	1
Consolidated	$ 278	$ 152	$ 128

(1) These are non-GAAP measures. A reconciliation of operating margin and EBIT to our operating income, earnings before income taxes and net income attributable to AGL Resources Inc. is located in "Results of Operations" herein.
(2) Includes intercompany eliminations.

Distribution operations' EBIT decreased by $11 million or 19% compared to last year as shown in the following table.

In millions		
EBIT for third quarter of 2008		$ 59
Operating margin		
Increased margins from gas storage carrying amounts at Atlanta Gas Light	$ 2	
Higher PRP revenues at Atlanta Gas Light	1	
Other	(1)	
Increase in operating margin		2

Operating expenses		
Increased pension and postretirement expenses	$ 6	
Increased payroll and incentive expenses	4	
Increased depreciation expenses	3	
Other	1	
Increase in operating expenses		(14)
Increase in other income		1
EBIT for third quarter of 2009		$ 48

Retail energy operations' EBIT increased by $19 million or 90% as shown in the following table.

In millions		
EBIT for third quarter of 2008		$ (21)
Operating margin		
LOCOM adjustment in 2008	$ 18	
Increased contributions from the management of storage and transportation assets offset by higher fixed interstate transportation costs	1	
Increased Ohio and interruptible operating margins	2	
Change in retail pricing plan mix and decrease in average number of customers	(2)	
Increase in operating margin		19
Operating expenses		
Increased marketing and direct selling expenses	$ 2	
Decreased customer care and outside services expenses	(2)	
Net change in operating expenses		-
EBIT for third quarter of 2009		$ (2)

Wholesale services' EBIT decreased by $88 million or 102% compared to last year as shown in the following table.

In millions		
EBIT for third quarter of 2008		$ 86
Operating margin		
Change on storage hedges as a result of forward NYMEX natural gas prices increasing this quarter as opposed to a significant decrease in the prior quarter	$ (110)	
Lower commercial activity from reduced volatility in the marketplace and mild weather	(17)	
Increased gains on transportation hedges from the narrowing of transportation basis spreads	2	
LOCOM adjustment in the third quarter of 2008, no adjustment was taken in the third quarter of 2009	34	
Decrease in operating margin		(91)
Operating expenses		
Decreased incentives and other expenses primarily associated with the decline in reported results	$ (3)	
Decrease in operating expenses		3

EBIT for third quarter of 2009	$	(2)

Glossary of Key Terms

Table of Contents

The following table indicates the components of wholesale services' operating margin for the three months ended September 30, 2009 and 2008.

In millions	2009	2008
Gain on transportation hedges	$ 14	$ 12
Commercial activity recognized	1	18
(Loss) gain on storage hedges	(5)	105
Inventory LOCOM, net of hedging recoveries	-	(34)
Operating margin	$ 10	$ 101

Energy investments' EBIT was flat compared to last year as shown in the following table.

In millions		
EBIT for third quarter of 2008		$ 3
Operating margin		
Increased operating revenues at AGL Networks	$ 1	
Increase in operating margin		1
Operating expenses		
Increased legal expenses and other outside services related to Jefferson Island litigation and increased depreciation expense at Golden Triangle Storage	$ 1	
Increase in operating expenses		(1)
EBIT for third quarter of 2009		$ 3

Nine months ended September 30, 2009 compared to nine months ended September 30, 2008

Segment information Operating margin, operating expenses and EBIT information for each of our segments are contained in the following table for the nine months ended September 30, 2009 and 2008.

In millions	Operating margin (1)	Operating expenses	EBIT (1)
2009			
Distribution operations	$ 615	$ 381	$ 241
Retail energy operations	121	55	66
Wholesale services	71	46	25

Energy investments	31	24	7
Corporate (2)	1	5	(4)
Consolidated	$ 839	$ 511	$ 335

In millions	Operating margin (1)	Operating expenses	EBIT (1)
2008			
Distribution operations	$ 599	$ 362	$ 239
Retail energy operations	101	54	47
Wholesale services	63	41	22
Energy investments	39	21	18
Corporate (2)	-	4	-
Consolidated	$ 802	$ 482	$ 326

(1) These are non-GAAP measures. A reconciliation of operating margin and EBIT to our operating income, earnings before income taxes and net income attributable to AGL Resources Inc. is located in "Results of Operations" herein.

(2) Includes intercompany eliminations.

Distribution operations' EBIT increased by $2 million or 1% compared to last year as shown in the following table.

In millions		
EBIT for nine months of 2008		$ 239
Operating margin		
Increased margins from gas storage carrying amounts at Atlanta Gas Light	$ 9	
Higher PRP revenues at Atlanta Gas Light	5	
Increased customer growth and increased usage at Virginia Natural Gas	4	
Change in estimated unbilled natural gas volumes recorded in prior year at Elizabethtown Gas	3	
Decreased customer growth and usage at Chattanooga Gas and Florida City Gas	(2)	
Decreased customer growth and reduced service fees at Atlanta Gas Light	(3)	
Increase in operating margin		16
Operating expenses		
Increased pension and postretirement expenses	$ 9	
Increased payroll and incentive expenses	7	
Increased depreciation expenses	6	
Increased environmental expenses	2	
Decreased marketing, outside services, facilities and vehicle fuel expenses	(5)	

Increase in operating expenses		(19)
Increase in other income, primarily from regulatory allowance for funds used during construction of Hampton Roads pipeline project at Virginia Natural Gas		5
EBIT for nine months of 2009	$	241

Glossary of Key Terms

Table of Contents

Retail energy operations' EBIT increased by $19 million or 40% as shown in the following table.

In millions		
EBIT for nine months of 2008		$ 47
Operating margin		
Increased contributions from the management of storage and transportation assets largely due to declining natural gas prices in 2009 offset by a prior year favorable pipeline rate order true-up	$ 16	
Change in LOCOM adjustment	12	
Increased operating margins in Ohio	4	
2008 pricing settlement with Georgia Commission	3	
Increased average customer usage	2	
Change in retail pricing plan mix and decrease in average number of customers	(17)	
Increase in operating margin		20
Operating expenses		
Increased marketing and direct selling expenses	$ 2	
Increased incentive compensation costs due to higher earnings	1	
Decreased customer care expenses	(3)	
Other	1	
Increase in operating expenses		(1)
EBIT for nine months of 2009		$ 66

Wholesale services' EBIT increased $3 million or 14% compared to last year as shown in the following table.

In millions		
EBIT for nine months of 2008		$ 22
Operating margin		
Increased gains on transportation hedges from the continued narrowing of basis spreads	$ 43	
Change in LOCOM adjustment net of estimated hedging recoveries	34	
Lower commercial activity from reduced volatility in the marketplace and mild weather	(21)	
Gains on storage hedges in the prior year due to decreases in forward NYMEX natural gas prices compared to storage hedge losses in the current year	(48)	
Increase in operating margin		8

Operating expenses		
Increased incentive compensation costs reflecting additional value captured in storage transactions and other accrued expenses	$ 5	
Increase in operating expenses		(5)
EBIT for nine months of 2009		$ 25

The following table indicates the components of wholesale services' operating margin for the nine months ended September 30, 2009 and 2008.

In millions	2009	2008
Gain on transportation hedges	$ 44	$ 1
Commercial activity recognized	29	50
(Loss) gain on storage hedges	(2)	46
Inventory LOCOM, net of hedging recoveries	-	(34)
Operating margin	$ 71	$ 63

Energy investments' EBIT decreased by $11 million or 61% compared to last year as shown in the following table.

In millions		
EBIT for nine months of 2008		$ 18
Operating margin		
Decreased operating margin at AGL Networks, primarily as a result of a network expansion project completed in 2008	$ (5)	
All other primarily due to decreased interruptible margins at Jefferson Island	(3)	
Decrease in operating margin		(8)
Operating expenses		
Increased legal expenses and other outside services related to Jefferson Island litigation	$ 1	
Increased depreciation, property taxes and other operating expenses primarily at Golden Triangle Storage	2	
Increase in operating expenses		(3)
EBIT for nine months of 2009		$ 7

Liquidity and Capital Resources

Our primary sources of liquidity are cash provided by operating activities, short-term borrowings under our commercial paper program (which is supported by our Credit Facility) and borrowings under subsidiary lines of credit. Additionally, from time to time, we raise funds from the public debt and equity capital markets to fund our liquidity and capital resource needs.

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

Table of Contents

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," of our Annual Report on Form 10-K for the year ended December 31, 2008, for additional information on items that could impact our liquidity and capital resource requirements. The following table provides a summary of our operating, investing and financing activities.

In millions	Nine months ended September 30, 2009	2008
Net cash provided by (used in):		
Operating activities	$ 686	$ 172
Investing activities	(314)	(254)
Financing activities	(367)	74
Net increase (decrease) in cash and cash equivalents	$ 5	$ (8)

Cash Flow from Operating Activities In the first nine months of 2009, our net cash flow provided from operating activities was $686 million, an increase of $514 million or 299% from the same period in 2008. This increase was primarily a result of the recovery of working capital during 2009 that was deployed in 2008 due to higher natural gas commodity prices. A primary contributor to the recovery of working capital was a $272 million increase in cash from our inventory withdrawals and $125 million increase in cash from the collection of our natural gas receivables. In addition, we received $101 million from decreased cash collateral requirements for our derivative financial instrument activities at Sequent and SouthStar due to the change in hedge values as forward NYMEX curve prices shifted downward in 2009.

The downward shift in the forward curve results in unrealized losses on the hedging instruments, comprised primarily of exchange traded derivatives, associated with anticipated natural gas purchases. 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. These unrealized losses are substantially offset by gains on derivative instruments utilized to hedge the price risk associated with the anticipated sale of these natural gas purchases. The anticipated economics of these transactions will ultimately be realized in the period when the natural gas is bought and sold.

Cash Flow from Investing Activities Our investing activities consisted of PP&E expenditures of $314 million for the nine months ended September 30, 2009 and $254 million for the same period in 2008. The increase of $60 million or 24% in PP&E expenditures was primarily due to a $35 million increase at distribution operations and a $28 million increase at energy investments.

The increased expenditures at distribution operations include $43 million in increased spending at Virginia Natural Gas' Hampton Roads Crossing pipeline project connecting its northern and southern systems. In addition, Elizabethtown Gas' enhanced infrastructure program resulted in a $10 million increase compared to 2008, as the program started earlier this year. These increases were offset by reduced expenditures of $16 million for the PRP at Atlanta Gas Light.

The increases at energy investments were primarily due to Golden Triangle Storage's natural gas storage facility. The increases at distribution operations and energy investments were partially offset by decreased PP&E expenditures at retail energy operations of $6 million primarily due to decreased spending on information technology assets compared to 2008, when GNG transitioned to a new customer care and call center vendor.

Cash Flow from Financing Activities Our cash used in financing activities was $367 million for the nine months ended September 30, 2009 compared to cash provided of $74 million for the same period in 2008. The increased cash use of $441 million was primarily due to increased short-term debt payments of $556 million in 2009 compared to net borrowings of $189 million for the same period in 2008. This was partially offset by our issuance of $300 million of senior notes in August 2009.

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-rate debt target is 20% to 45% of total debt), as well as the term and interest rate profile of our debt securities. As of September 30, 2009, our variable-rate debt was 21% of our total debt, compared to 38% as of September 30, 2008.

We also work to maintain or improve our credit ratings to manage our existing financing costs effectively and enhance our ability to raise additional capital on favorable terms. Factors we consider important in assessing our credit ratings include our statements of financial position leverage, capital spending, earnings, cash flow generation, available liquidity and overall business risks. We do not have any trigger events in our debt instruments that are tied to changes in our specified credit ratings 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 September 30, 2009, and reflects no change from December 31, 2008.

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

Glossary of Key Terms

Table of Contents

Our credit ratings may be subject to revision or withdrawal at any time by the assigning rating organization, and each rating should be evaluated independently of any other rating. We cannot ensure that a rating will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. If the rating agencies downgrade our ratings, particularly below investment grade, it may significantly limit our access to the commercial paper market and our borrowing costs would increase. In addition, we would likely be required to pay a higher interest rate in future financings, and our potential pool of investors and funding sources would decrease.

Default events Our debt instruments and other financial obligations include provisions that, if not complied with, could require early payment, additional collateral support or similar actions. Our most important default events include maintaining covenants with respect to a maximum leverage ratio, insolvency events, nonpayment of scheduled principal or interest payments, and acceleration of other financial obligations and change of control provisions.

Our Credit Facility has financial covenants that require us to maintain a ratio of total debt to total capitalization of no greater than 70%; however, our goal is to maintain this ratio at levels between 50% and 60%. Our ratio of total debt to total capitalization calculation contained in our debt covenant includes standby letters of credit, surety bonds and the exclusion of other comprehensive income pension adjustments. Our debt to total capitalization calculation, as defined by our Credit Facility was 55% at September 30, 2009, 59% at December 31, 2008 and 58% at September 30, 2008. These amounts are within our required and targeted ranges. Our debt to total capitalization ratios as calculated from our condensed consolidated statements of financial position, as of the dates indicated, are summarized in the following table.

	Sept. 30, 2009	Dec. 31, 2008	Sept. 30, 2008
Short-term debt	8 %	20 %	18 %
Long-term debt	49	40	40
Total debt	57	60	58
Equity	43	40	42
Total capitalization	100 %	100 %	100 %

We believe that accomplishing our capitalization objectives and maintaining sufficient cash flow are necessary to maintain our investment-grade credit ratings and to allow us access to capital at reasonable costs. We currently comply with all existing debt provisions and covenants.

Short-term debt Our short-term debt is composed of borrowings and payments under our Credit Facility and commercial paper program, lines of credit and the current portion of our capital leases. Our short-term debt financing generally increases between June and December because our payments for natural gas and pipeline capacity are generally made to suppliers prior to the collection of accounts receivable from our customers. We typically reduce short-term debt balances in the spring because a significant portion of our current assets are converted into cash at the end of the heating season.

Our short-term borrowings, as of September 30, 2009, decreased $459 million or 60% compared to the same period last year. This was primarily a result of paying down short-term debt with a portion of the proceeds received from the issuance of $300 million of senior notes in August 2009, and reduced working capital requirements as a result of lower natural gas prices. This was offset by increased property, plant and equipment expenditures of $60 million.

Our commercial paper borrowings are supported by our $1 billion Credit Facility which expires in August 2011. Our supplemental $140 million Credit Facility, which we completed last year to provide additional liquidity for working capital and capital expenditure needs, expired in September 2009. We have the option to request an increase in the aggregate principal amount available for borrowing under the $1 billion Credit Facility to $1.25 billion on not more than three occasions during each calendar year. SouthStar has a $75 million line of credit which is used for its working capital and general corporate needs. Additionally, Sequent has a $5 million line of credit that is used solely for the posting of margin deposits for NYMEX transactions. Both of these lines of credit had no amounts outstanding as of September 30, 2009.

The lenders under our Credit Facility and lines of credit are major financial institutions with committed balances and investment grade credit ratings as of September 30, 2009 as indicated in the following table. Investment grade, in the context of bond ratings, is the rating level above which institutional investors are authorized to invest (a bond judged likely enough to meet payment obligations that banks and pensions are allowed to invest in it).

Lender rating (S&P / Moody's)		Amount committed (in millions)	% of total	
AAA / Aaa	$	-	-	
AA / Aa		328	31	%
A / A		582	54	%
BBB / Baa		165	15	%
Total	$	1,075	100	%

Based on current credit market conditions, it is possible that one or more lending commitments could be unavailable to us if the lender defaulted due to lack of funds or insolvency. However, based on our current assessment of our lenders' creditworthiness, we believe the risk of lender default is minimal.

Glossary of Key Terms

As of September 30, 2009 we had no outstanding borrowings under our Credit Facility. As of December 31, 2008, we had $500 million of outstanding borrowings under the Credit Facility. Additionally, at September 30, 2008, we had $485 million of outstanding borrowings under the Credit Facility. We normally access the commercial paper markets to finance our working capital needs. However, during the third and fourth quarters of 2008, adverse developments in the global financial and credit markets made it more difficult for us to access the commercial paper market at reasonable rates. In 2009, the credit markets have improved, allowing us to resume our commercial paper borrowings.

Long-term debt Our long-term debt matures more than one year from the date of our statements of financial position and consists of medium-term notes, senior notes, gas facility revenue bonds, and capital leases. In August 2009, AGL Capital issued $300 million of 10-year senior notes at an interest rate of 5.25%. The net proceeds from the offering were approximately $297 million. We used the net proceeds from the sale of the senior notes to repay a portion of our short-term debt.

Contractual Obligations and Commitments We have incurred various contractual obligations and financial commitments in the normal course of our operating and financing activities. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements. These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related revenue producing activities. We also have incurred various financial commitments in the normal course of business. Contingent financial commitments represent obligations that become payable only if certain predefined events occur, such as financial guarantees, and include the nature of the guarantee and the maximum potential amount of future payments that could be required of us as the guarantor.

In the first nine months of 2009, we contributed $21 million to our qualified pension plans. We contributed an additional $3 million in October 2009; however, we do not expect to make any additional contributions to our pension plans in 2009. In 2008, we did not make a contribution, as one was not required. We previously expected that our total required and additional contributions to our pension plans would be approximately $68 million to preserve the current levels of benefits under our pension plans and in accordance with the funding requirements of the Pension Protection Act. The reduction in our expected contributions are a result of a notice from the Internal Revenue Service with respect to proposed changes to the pension funding rules that allowed using a discount rate that was higher than the discount rate we used in our previous estimate. Consequently, our pension liabilities as calculated under the funding rules were reduced and the 2009 funding requirements decreased to maintain current benefits levels. The following table illustrates our expected future contractual obligation payments such as debt and lease agreements, and commitments and contingencies as of September 30, 2009.

In millions	Total	2009	2010 & 2011	2012 & 2013	2014 & thereafter
Recorded contractual obligations:					
Long-term debt	$ 1,975	$ -	$ 301	$ 242	$ 1,432
Short-term debt	310	309	1	-	-
PRP costs (1)	155	14	93	48	-
Environmental remediation liabilities (1)	130	7	43	53	27
Total	$ 2,570	$ 330	$ 438	$ 343	$ 1,459
Unrecorded contractual obligations and commitments (2):					
	$ 1,712	$ 151	$ 755	$ 390	$ 416

Pipeline charges, storage capacity and gas supply (3)					
Interest charges (4)	1,043	28	198	167	650
Operating leases	122	9	49	27	37
Asset management agreements (5)	41	6	33	2	-
Standby letters of credit, performance / surety bonds	26	9	16	1	-
Total	$ 2,944	$ 203	$ 1,051	$ 587	$ 1,103

(1) Includes charges recoverable through rate rider mechanisms.

(2) In accordance with GAAP, these items are not reflected in our condensed consolidated statements of financial position.

(3) Charges recoverable through a natural gas cost recovery mechanism or alternatively billed to Marketers, and includes demand charges associated with Sequent. Also includes SouthStar's gas natural gas purchase commitments of 20 Bcf at floating gas prices calculated using forward natural gas prices as of September 30, 2009, and are valued at $78 million. Additionally, includes amounts associated with a subsidiary of NUI which entered into two 20-year agreements for the firm transportation and storage of natural gas during 2003 with annual aggregate demand charges of approximately $5 million. As a result of our acquisition of NUI and in accordance with the authoritative guidance related to business combinations, we valued the contracts at fair value and established a long-term liability of $38 million for the excess liability that will be amortized to our consolidated statements of income over the remaining lives of the contracts of $2 million annually through November 2023 and $1 million annually from November 2023 to November 2028.

(4) Floating rate debt is based on the interest rate as of September 30, 2009, and the maturity of the underlying debt instrument. As of September 30, 2009, we have $33 million of accrued interest on our condensed consolidated statements of financial position that will be paid over the next 12 months.

(5) Represent fixed-fee minimum payments for Sequent's asset management agreements.

Glossary of Key Terms

Critical Accounting Policies and Estimates

The preparation of our financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. We evaluate our estimates on an ongoing basis, and our actual results may differ from these estimates. Our critical accounting policies used in the preparation of our condensed consolidated financial statements include the following:

- Pipeline Replacement Program
- Environmental Remediation Liabilities
- Derivatives and Hedging Activities
- Pension and Other Postretirement Plans
- Income Taxes

Each of our critical accounting policies and estimates involves complex situations requiring a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our financial statements. There have been no significant changes to our critical accounting policies from those disclosed in our recast Management's Discussion and Analysis of Financial Condition and Results of Operation as filed on Form 8-K with the SEC on July 13, 2009.

Accounting Developments

Subsequent Events

In May 2009, the FASB issued additional authoritative guidance for and disclosure of events that occur after the statement of financial position date, but before financial statements are issued, or are available to be issued. In accordance with the additional guidance, we evaluated and disclosed in Note 1 subsequent events until the time that our financial statements were issued and filed with the SEC on October 29, 2009.

Fair Value Measurements

In April 2009, additional authoritative guidance related to fair value measurements and disclosures established a two-step process to determine if the market for a financial asset is inactive and a transaction is not distressed. Currently, this authoritative guidance does not affect us, as our derivative financial instruments are traded in active markets.

In August 2009, the FASB updated the fair value measurement guidance to provide clarity on the methodologies and disclosures for fair value estimates of liabilities that do not have a quoted price in an active market or, level 3 liabilities. Any revisions due to a change in valuation technique, or its application, are to be accounted for as a change in accounting method. Disclosure is required for any change in valuation technique or related inputs resulting from the application of this update and the total effect would need to be quantified, if practicable. This update is effective for reporting periods ending after September 15, 2009, and had no financial impact to our condensed consolidated results of operations, cash flows or financial position. Our fair value measurements are described in further detail in Note 2 and Note 6.

Derivative Financial Instruments

The amendment to authoritative guidance related to derivatives and hedging provides an enhanced understanding of how and why derivative instruments are used, how they are accounted for and their effect on our financial condition, performance and cash flows. We adopted this guidance on January 1, 2009, and provided the required additional disclosures, but it had no financial impact to our condensed consolidated results of operations, cash flows or financial condition.

In 2009, additional authoritative guidance requiring more detailed disclosures about credit derivatives, including the potential adverse effects of changes in credit risk on the financial position, financial performance and cash flows of the sellers of the instruments was issued. This guidance had no financial impact to our condensed consolidated results of operations, cash flows or financial condition. We adopted this authoritative guidance on January 1, 2009. Our derivative financial instruments are described in further detail in Note 3.

Employee Benefit Plans

Additional authoritative guidance related to retirement benefits requires disclosures relating to postretirement benefit plan assets to provide transparency regarding the types of assets and the associated risks within the types of plan assets.

This authoritative guidance is effective for fiscal years ending after December 15, 2009 and requires additional disclosures in our notes to condensed consolidated financial statements, but will not have a material impact on our financial position, consolidated results of operations or cash flows. Our employee benefit plans are described in further detail in Note 4.

Variable Interest Entity

In June 2009, the FASB issued guidance, which amended the guidance related to transfers and servicing. This guidance requires improved disclosures about transfers of financial assets and removes the exception from applying the guidance related to consolidations specifically for variable interest entities (VIE) to qualifying special purpose entities. This amendment will be effective for us on January 1, 2010 and it will have no effect on our consolidated results of operations, cash flows or financial position.

Glossary of Key Terms

In June 2009, the FASB issued additional consolidation guidance for VIE. The guidance requires us to assess the determination of the primary beneficiary of a VIE based on whether we have the power to direct matters that most significantly impact the activities of the VIE, and has the obligation to absorb losses or the right to receive benefits of the VIE. In addition, the guidance requires ongoing reassessments of whether we are the primary beneficiary of a VIE. The guidance will be effective for us beginning January 1, 2010. Earlier application is prohibited. We are currently evaluating the impact of this guidance on our consolidated results of operations, cash flows and financial position. Our VIE is described in further detail in Note 5.

General Principles

In June 2009, the FASB issued the authoritative guidance, which replaces the previous authoritative hierarchy aspect of GAAP. The guidance creates a two-level GAAP hierarchy - authoritative and non-authoritative - and establishes the guidance as the sole source of authoritative GAAP for non-governmental entities, except for rules and releases by the SEC.

After July 1, 2009, all non-grandfathered, non-SEC accounting guidance not included in the authoritative guidance is superseded and is deemed non-authoritative. The guidance is effective for financial statements issued for interim and annual periods ending after September 15, 2009. The guidance will have no impact on our consolidated results of operations, cash flows or financial position.

Item 3. Quantitative and Qualitative Disclosures
About Market Risk

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

Our Risk Management Committee (RMC) is responsible for establishing the overall risk management policies and monitoring compliance with, and adherence to, the terms within these policies, including approval and authorization levels and delegation of these levels. Our RMC consists of members of senior management who monitor open natural gas price risk positions and other types of risk, corporate exposures, credit exposures and overall results of our risk management activities. It is chaired by our chief risk officer, who is responsible for ensuring that appropriate reporting mechanisms exist for the RMC to perform its monitoring functions. Our risk management activities and related accounting treatment for our derivative financial instruments are described in further detail in Note 3.

Natural Gas Price Risk

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

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

The following tables illustrate the change in the net fair value of the derivative financial instruments during the three and nine months ended September 30, 2009 and 2008, and provide details of the net fair value of derivative financial instruments outstanding as of September 30, 2009.

	Three months ended Sept. 30,	
In millions	2009	2008
Net fair value of derivative financial instruments outstanding at beginning of period	$ (5)	$ 8
Derivative financial instruments realized or otherwise settled during period	9	(4)
Change in net fair value of derivative financial instruments	4	8
Net fair value of derivative financial instruments outstanding at end of period (1)	8	12
Netting of cash collateral	8	20
Cash collateral and net fair value of derivative financial instruments outstanding at end of period (1)	$ 16	$ 32

(1) Net fair value of derivative financial instruments outstanding includes $3 million premium at September 30, 2009 and $1 million at September 30, 2008 associated with weather derivatives.

Glossary of Key Terms

In millions	Nine months ended Sept. 30, 2009	2008
Net fair value of derivative financial instruments outstanding at beginning of period	$ (17)	$ 10
Derivative financial instruments realized or otherwise settled during period	22	(10)
Change in net fair value of derivative financial instruments	3	12
Net fair value of derivative financial instruments outstanding at end of period (1)	8	12
Netting of cash collateral	8	20
Cash collateral and net fair value of derivative financial instruments outstanding at end of period (1)	$ 16	$ 32

(1) Net fair value of derivative financial instruments outstanding includes $3 million premium at September 30, 2009 and $1 million at September 30, 2008 associated with weather derivatives.

The sources of SouthStar's net fair value of its natural gas-related derivative financial instruments at September 30, 2009, are as follows:

In millions	Prices actively quoted (Level 1) (1)	Significant other observable inputs (Level 2) (2)
Mature through		
2009	$ (3)	$ 1
2010	7	3
Total derivative financial instruments (3)	$ 4	$ 4

(1) Valued using NYMEX futures prices

(2) Values primarily related to weather derivative transactions that are valued on an intrinsic basis in accordance with authoritative guidance related to financial instruments as based on heating degree days. Additionally includes values associated with basis transactions that represent the commodity from 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.

The following tables include the fair values and average values of SouthStar's derivative instruments as of the dates indicated. SouthStar bases the average values on monthly averages for the nine months ended September 30, 2009 and 2008.

In millions	Derivative financial instruments average fair values (1) at September 30, 2009	2008
Asset	$ 12	$ 13

Liability	23	5

(1) Excludes cash collateral amounts.

In millions	Derivative financial instruments fair values netted with cash collateral at Sept. 30, 2009	Dec. 31, 2008	Sept. 30, 2008
Asset	$ 16	$ 16	$ 33
Liability	-	2	1

Value at Risk A 95% confidence interval is used to evaluate VaR exposure. A 95% confidence interval means that over the holding period, an actual loss in portfolio value is not expected to exceed the calculated VaR more than 5% of the time. We calculate VaR based on the variance-covariance technique. This technique requires several assumptions for the basis of the calculation, such as price distribution, price volatility, confidence interval and holding period. Our VaR may not be comparable to a similarly titled measure of another company because, although VaR is a common metric in the energy industry, there is no established industry standard for calculating VaR or for the assumptions underlying such calculations. SouthStar's portfolio of positions for the nine months ended September 30, 2009 and 2008 had quarterly average 1-day holding period VaRs of less than $100,000 and its high, low and period end 1-day holding period VaR were immaterial.

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

The following tables include the fair values and average values of Sequent's derivative financial instruments as of the dates indicated. Sequent bases the average values on monthly averages for the nine months ended September 30, 2009 and 2008.

In millions	Derivative financial instruments average values (1) at September 30, 2009	2008
Asset	$ 169	$ 72
Liability	75	48

(1) Excludes cash collateral amounts.

In millions	Derivative financial instruments fair values netted with cash collateral at Sept. 30, 2009	Dec. 31, 2008	Sept. 30, 2008
Asset	$ 146	$ 206	$ 140
Liability	17	27	24

Sequent experienced a $27 million decrease and a $26 million increase in the net fair value of its outstanding contracts during the first nine months of 2009 and 2008, respectively, due to changes in the fair value of derivative financial instruments utilized in its energy marketing and risk management activities and contract settlements.

The following tables illustrate the change in the net fair value of Sequent's derivative financial instruments during the three and nine months ended September 30, 2009 and 2008, and provide details of the net fair value of contracts outstanding as of September 30, 2009.

Glossary of Key Terms

In millions	Three months ended September 30, 2009	2008
Net fair value of derivative financial instruments outstanding at beginning of period	$ 56	$ (96)
Derivative financial instruments realized or otherwise settled during period	(9)	60
Change in net fair value of derivative financial instruments	8	119
Net fair value of derivative financial instruments outstanding at end of period	55	83
Netting of cash collateral	74	33
Cash collateral and net fair value of derivative financial instruments outstanding at end of period	$ 129	$ 116

In millions	Nine months ended September 30, 2009	2008
Net fair value of derivative financial instruments outstanding at beginning of period	$ 82	$ 57
Derivative financial instruments realized or otherwise settled during period	(77)	(48)
Change in net fair value of derivative financial instruments	50	74
Net fair value of derivative financial instruments outstanding at end of period	55	83
Netting of cash collateral	74	33
Cash collateral and net fair value of derivative financial instruments outstanding at end of period	$ 129	$ 116

The sources of Sequent's net fair value of its natural gas-related derivative financial instruments at September 30, 2009, are as follows:

In millions	Prices actively quoted (Level 1) (1)	Significant other observable inputs (Level 2) (2)
Mature through		
2009	$ (21)	$ 29
2010 - 2011	(21)	66
2012 - 2014	1	1
Total derivative financial instruments (3)	$ (41)	$ 96

(1) Valued using NYMEX futures prices and other quoted sources.

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

Sequent's management actively monitors open natural gas positions and the resulting VaR. Sequent continues to maintain a relatively matched book, where its total buy volume is close to sell volume with minimal open natural gas price risk. Based on a 95% confidence interval and employing a 1-day holding period for all positions, Sequent's portfolio of positions for the three and nine months ended September 30, 2009 and 2008 had the following VaRs.

	Three months ended September 30,		Nine months ended September 30,	
In millions	2009	2008	2009	2008
Period end	$ 1.9	$ 1.9	$ 1.9	$ 1.9
Average	1.6	1.8	1.9	1.7
High	2.5	2.4	3.3	2.9
Low	1.2	1.0	1.2	0.8

Energy Investments In 2009, Golden Triangle Storage began using derivative financial instruments to reduce its exposure during the construction of the storage caverns to the risk of changes with the price of natural gas that will be purchased in future periods for pad gas, which includes volumes of non-working natural gas used to maintain the operational integrity of the caverns. As of September 30, 2009, Golden Triangle Storage had locked-in the price of approximately 67% of the required pad gas for the first storage cavern or 2 Bcf with a fair value of approximately $1 million.

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 $470 million of variable-rate debt, which includes $309 million of our variable-rate short-term debt and $161 million of variable-rate gas facility revenue bonds outstanding at September 30, 2009, a 100 basis point change in average market interest rates from 0.5% to 1.5% would have resulted in an increase in pretax interest expense of $5 million on an annualized basis.

Glossary of Key Terms

Table of Contents

Credit Risk

Wholesale Services Sequent has established credit policies to determine and monitor the creditworthiness of counterparties, as well as the quality of pledged collateral. Sequent also utilizes master netting agreements whenever possible to mitigate exposure to counterparty credit risk. When Sequent is engaged in more than one outstanding derivative transaction with the same counterparty and it has a legally enforceable netting agreement with that counterparty, the “net” mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of Sequent’s credit risk. Sequent also uses other netting agreements with certain counterparties with whom it conducts significant transactions. Master netting agreements enable Sequent to net certain assets and liabilities by counterparty. Sequent also nets across product lines and against cash collateral provided the master netting and cash collateral agreements include such provisions.

Additionally, Sequent may require counterparties to pledge additional collateral when deemed necessary. Sequent conducts credit evaluations and obtains appropriate internal approvals for its counterparty’s line of credit before any transaction with the counterparty is executed. In most cases, the counterparty must have an investment grade rating, which includes a minimum long-term debt rating of Baa3 from Moody’s and BBB- from S&P. Generally, Sequent requires credit enhancements by way of guaranty, cash deposit or letter of credit for counterparties that do not have investment grade ratings.

Sequent, which provides services to marketers and utility and industrial customers, also has a concentration of credit risk as measured by its 30-day receivable exposure plus forward exposure. As of September 30, 2009, Sequent’s top 20 counterparties represented approximately 64% of the total counterparty exposure of $223 million, derived by adding together the top 20 counterparties’ exposures and dividing by the total of Sequent’s counterparties’ exposures.

As of September 30, 2009 Sequent’s counterparties, or the counterparties’ guarantors, had a weighted-average S&P equivalent credit rating of A-, which is consistent with the credit ratings at September 30, 2008 and December 31, 2008. The S&P equivalent credit rating is determined by a process of converting the lower of the S&P and Moody’s ratings to an internal rating ranging from 9 to 1, with 9 being the 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 for that counterparty. To arrive at the weighted average credit rating, each counterparty is assigned an internal ratio, which is multiplied by their credit exposure and summed for all counterparties. The sum is divided by the aggregate total counterparties’ exposures, and this numeric value is then converted to an S&P equivalent. There were no credit defaults with Sequent’s counterparties. The following table shows Sequent’s third-party natural gas contracts receivable and payable positions as of September 30, 2009 and 2008 and December 31, 2008.

	Gross receivables			Gross payables		
In millions	Sept. 30, 2009	Dec. 31, 2008	Sept. 30, 2008	Sept. 30, 2009	Dec. 31, 2008	Sept. 30, 2008
Netting agreements in place:						
Counterparty is investment grade	$ 163	$ 398	$ 446	$ 113	$ 266	$ 338
Counterparty is non-investment grade	3	15	10	12	41	16
Counterparty has no external rating	45	129	76	119	228	212
No netting agreements in place:						
	5	7	3	1	4	2

Counterparty is investment grade						
Counterparty is non-investment grade	-	-	-	-	-	-
Amount recorded on statements of financial position	$ 216	$ 549	$ 535	$ 245	$ 539	$ 568

Sequent has certain trade and credit contracts that have explicit minimum credit rating requirements. These credit rating requirements typically give counterparties the right to suspend or terminate credit if our credit ratings are downgraded to non-investment grade status. Under such circumstances, Sequent would need to post collateral to continue transacting business with some of its counterparties. If such collateral were not posted, Sequent's ability to continue transacting business with these counterparties would be impaired. If our credit ratings had been downgraded to non-investment grade status, the required amounts to satisfy potential collateral demands under such agreements between Sequent and its counterparties would have totaled $6 million at September 30, 2009, which would not have a material impact to our condensed consolidated results of operations, cash flows or financial condition.

There have been no other significant changes to our credit risk related to our other segments, as described in Item 7A "Quantitative and Qualitative Disclosures about Market Risk" of our Annual Report on Form 10-K for the year ended December 31, 2008.

Glossary of Key Terms

Table of Contents

Item 4. Controls and Procedures

(a) Evaluation 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 in Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act), as of September 30, 2009, the end of the period covered by this report. Based on this evaluation, our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were effective as of September 30, 2009, 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.

(b) Changes in internal control over financial reporting. There were no changes in our internal control over financial reporting during our most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1. Legal Proceedings

The nature of our business ordinarily results in periodic regulatory proceedings before various state and federal authorities and litigation incidental to the business. For information regarding pending federal and state regulatory matters, see “Note 7 - Commitments and Contingencies” contained in Item 1 of Part I under the caption “Notes to Condensed Consolidated Financial Statements (Unaudited).”

In March 2009, Piedmont filed a lawsuit in the Court of Chancery of the State of Delaware against us asking the court to enter a judgment declaring that our right to purchase Piedmont’s ownership interest in SouthStar expires on November 1, 2009. We have reached a settlement agreement with Piedmont that will dismiss the lawsuit and will result in a restructuring of the ownership interests in the SouthStar joint venture. Under the terms of the agreement, which has been approved by the boards of directors of both companies, we will purchase an additional 15% ownership share in the joint venture from Piedmont for $58 million. As a result, we will own 85% of the SouthStar joint venture, and will be entitled to 85% of the annual earnings from the business, while Piedmont will retain the remaining 15% share. As part of the agreement, our interest will remain a noncontrolling interest and we will not have any further option rights to Piedmont’s remaining 15% ownership interest. The agreement was approved by the Georgia Commission in October 2009 and the effective date of the transaction will be January 1, 2010.

With regard to other legal proceedings, we are a party, as both plaintiff and defendant, to a number of other suits, claims and counterclaims on an ongoing basis. Management believes that the outcome of all such other litigation in which it is involved will not have a material adverse effect on our consolidated financial statements.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The following table sets forth information about purchases of our common stock by us and any affiliated purchasers during the three months ended September 30, 2009. Stock repurchases may be made in the open market or in private transactions at times and in amounts that we deem appropriate. However, there is no guarantee as to the exact number of additional shares that may be repurchased, and we may terminate or limit the stock repurchase program at any time. We currently anticipate holding the repurchased shares as treasury shares.

Period	Total number of shares purchased (1) (2)	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs (2)	Maximum number of shares that may yet be purchased under the publicly announced plans or programs (2)
July 2009	-	$ -	-	4,950,951
August 2009	2,443	33.64	-	4,950,951
September 2009	-	-	-	4,950,951
Total third quarter	2,443	$ 33.64	-	

(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 2,443 shares for such purposes in the third quarter of 2009. As of September 30, 2009, we had purchased a total of 324,860 of the 600,000 shares authorized for purchase, leaving 275,140 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.

Item 5. Other Information

In connection with the settlement reached with Piedmont previously described under "Item 1 – Legal Proceedings," on July 29, 2009, GNG entered into a Third Amendment to the Amended and Restated Limited Liability Company Agreement by and between GNG and Piedmont. The material terms of the third Amendment, which is filed herewith as Exhibit 10.1, are summarized in the second paragraph under "Item 1 – Legal Proceedings" above, which summary is incorporated by reference under this Item 5.

Item 6. Exhibits

1.1 Underwriting Agreement, dated August 5, 2009, by and among AGL Capital Corporation, as issuer, AGL Resources Inc., as guarantor, and Wells Fargo Securities, LLC, for itself and on behalf of the several underwriters listed on Schedule A thereto (Exhibit 1.1, AGL Resources, Inc. Form 8-K dated August 5, 2009).

4.1 Specimen AGL Capital Corporation, 5.25% Senior Notes due 2019 (Exhibit 4.1, AGL Resources, Inc. Form 8-K dated August 5, 2009).

4.2

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 dated August 5, 2009).

10.1 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).

10.2 Environmental Services Agreement, dated July 16, 2009, by and between Atlanta Gas Light Company and MACTEC Engineering and Consulting, Inc.

12 Statement of Computation of Ratio of Earnings to Fixed Charges.

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.

Glossary of Key Terms

Table of Contents

SIGNATURE

Pursuant to the requirements 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.

AGL RESOURCES INC.
(Registrant)

Date: October 29, 2009 /s/ Andrew W. Evans
Executive Vice President, Chief Financial Officer and Treasurer

Glossary of Key Terms