AGL RESOURCES INC
Form 10-Q
July 31, 2013

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 June 30, 2013

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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No ¨

Indicate by check mark 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 July 24, 2013
Common Stock, $5.00 Par Value	118,592,240

AGL RESOURCES INC.
Quarterly Report on Form 10-Q
For the Quarter Ended June 30, 2013

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GLOSSARY OF KEY TERMS

2012 Form 10-K	Our Annual Report on Form 10-K for the year ended December 31, 2012, filed with the SEC on February 6, 2013
AGL Capital	AGL Capital Corporation
AGL Credit Facility	$1.3 billion credit agreement entered into by AGL Capital to support the AGL Capital commercial paper program
Atlanta Gas Light	Atlanta Gas Light Company
Bcf	Billion cubic feet
Central Valley	Central Valley Gas Storage, LLC
Chattanooga Gas	Chattanooga Gas Company
Compass Energy	Compass Energy Services, Inc.
EBIT	Earnings before interest and taxes, a non-GAAP measure that includes operating income and other income and excludes financing costs, including interest on debt, and income tax expense, each of which we evaluate on a consolidated level.
Fitch	Fitch Ratings
GAAP	Accounting principles generally accepted in the United States of America
Georgia Commission	Georgia Public Service Commission, the state regulatory agency for Atlanta Gas Light
Golden Triangle Storage	Golden Triangle Storage, Inc.
Heating Degree Days	A measure of the effects of weather on our businesses, calculated as the extent to which the average daily temperature is less than 65 degrees Fahrenheit
Heating Season	The period from November through March when natural gas usage and operating revenues are generally higher
Horizon Pipeline	Horizon Pipeline Company, LLC
Illinois Commission	Illinois Commerce Commission, the state regulatory agency for Nicor Gas
LIFO	Last-in, first-out
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, the state regulatory agency for Elizabethtown Gas
Nicor	Nicor Inc. - an acquisition completed in December 2011 and former holding company of Nicor Gas
Nicor Advanced Energy	Prairie Point Energy, LLC, doing business as Nicor Advanced Energy
Nicor Gas	Northern Illinois Gas Company, doing business as Nicor Gas Company
Nicor Gas Credit Facility	$700 million credit facility entered into by Nicor Gas to support its commercial paper program
Nicor Services	Nicor Energy Services Company
Nicor Solutions	Nicor Solutions, LLC
NUI	NUI Corporation - an acquisition completed in November 2004
NYMEX	New York Mercantile Exchange, Inc.
OCI	Other comprehensive income
Operating margin	A non-GAAP measure of income, calculated as operating revenues minus cost of goods sold and revenue tax expense, that excludes operation and maintenance expense, depreciation and

	amortization, certain taxes other than income taxes, Nicor merger expenses and gains or losses on the sale of our assets, if any.
OTC	Over-the-counter
PBR	Performance-based rate, a regulatory plan at Nicor Gas that provided economic incentives based on natural gas cost performance. The plan terminated in 2003.
Piedmont	Piedmont Natural Gas Company, Inc.
PP&E	Property, plant and equipment
S&P	Standard & Poor's Ratings Services
SEC	Securities and Exchange Commission
Sequent	Sequent Energy Management, L.P.
Seven Seas	Seven Seas Insurance Company, Inc.
SouthStar	SouthStar Energy Services, LLC
STRIDE	Atlanta Gas Light's Strategic Infrastructure Development and Enhancement program
Tennessee Authority	Tennessee Regulatory Authority, the state regulatory agency for Chattanooga Gas
TEU	Twenty-foot equivalent unit, a measure of volume in containerized shipping equal to one 20-foot-long container
Triton	Triton Container Investments, LLC
Tropical Shipping	Tropical Shipping and Construction Company Limited
VaR	Value at risk
VIE	Variable interest entity
Virginia Commission	Virginia State Corporation Commission, the state regulatory agency for Virginia Natural Gas
Virginia Natural Gas	Virginia Natural Gas, Inc.
WACOG	Weighted average cost of gas

PART I – FINANCIAL INFORMATION
Item 1. Condensed Consolidated Financial Statements (Unaudited)

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

In millions, except share amounts	As of June 30, 2013	December 31, 2012	June 30, 2012
Current assets			
Cash and cash equivalents	$ 184	$ 131	$ 87
Short-term investments	42	58	61
Receivables			
Energy marketing receivables	608	677	347
Gas, unbilled and other receivables	437	686	349
Less allowance for uncollectible accounts	41	28	39
Total receivables	1,004	1,335	657
Inventories, net	530	708	549
Regulatory assets	120	145	146
Derivative instruments	113	130	181
Other current assets	70	161	199
Total current assets	2,063	2,668	1,880
Long-term assets and other deferred debits			
Property, plant and equipment	10,761	10,478	10,091
Less accumulated depreciation	2,264	2,131	2,004
Property, plant and equipment, net	8,497	8,347	8,087
Goodwill	1,883	1,837	1,813
Regulatory assets	898	944	1,083
Intangible assets	184	96	100
Derivative instruments	17	14	45
Other	253	235	221
Total long-term assets and other deferred debits	11,732	11,473	11,349
Total assets	$ 13,795	$ 14,141	$ 13,229
Current liabilities			
Energy marketing trade payable	$ 628	$ 611	$ 383
Short-term debt	521	1,377	731
Accounts payable - trade	344	334	248
Regulatory liabilities	216	161	137
Accrued expenses	170	140	138
Customer deposit and credit balances	114	143	139
Temporary LIFO liquidation	84	-	41
	62	57	59

Accrued environmental remediation liabilities			
Accrued regulatory infrastructure program costs	55	121	158
Derivative instruments	33	33	58
Current portion of long-term debt and capital leases	-	226	231
Other current liabilities	122	135	137
Total current liabilities	2,349	3,338	2,460
Long-term liabilities and other deferred credits			
Long-term debt	3,819	3,327	3,334
Accumulated deferred income taxes	1,567	1,588	1,509
Regulatory liabilities	1,510	1,477	1,453
Accrued environmental remediation liabilities	406	387	371
Accrued retiree welfare benefits	264	268	296
Accrued pension obligations	246	240	221
Derivative instruments	6	6	8
Other long-term liabilities and other deferred credits	73	75	148
Total long-term liabilities and other deferred credits	7,891	7,368	7,340
Total liabilities and other deferred credits	10,240	10,706	9,800
Commitments, guarantees and contingencies (see Note 9)			
Equity			
Common stock, $5 par value; 750,000,000 shares authorized: outstanding: 118,560,687 shares at June 30, 2013, 117,855,075 shares at December 31, 2012 and 117,505,440 shares at June 30, 2012	594	590	589
Additional paid in capital	2,035	2,014	2,003
Retained earnings	1,127	1,035	1,035
Accumulated other comprehensive loss	(209)	(218)	(207)
Treasury shares, at cost: 216,523 shares at June 30, 2013 and December 31, 2012 and June 30, 2012	(8)	(8)	(8)
Total common shareholders' equity	3,539	3,413	3,412
Noncontrolling interest	16	22	17
Total equity	3,555	3,435	3,429
Total liabilities and equity	$ 13,795	$ 14,141	$ 13,229

See Notes to Condensed Consolidated Financial Statements (Unaudited).

Glossary of Key Terms

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

	Three months ended June 30,		Six months ended June 30,	
In millions, except per share amounts	2013	2012	2013	2012
Operating revenues (include revenue taxes of $24 and $74 for the three and six months in 2013 and $14 and $55 for the three and six months in 2012)	$904	$686	$2,613	$2,090
Operating expenses				
Cost of goods sold	407	240	1,380	959
Operation and maintenance	233	218	492	463
Depreciation and amortization	109	102	216	206
Taxes other than income taxes	44	32	115	96
Nicor merger expenses	-	3	-	13
Total operating expenses	793	595	2,203	1,737
Gain on sale of Compass Energy	11	-	11	-
Operating income	122	91	421	353
Other income	7	9	12	13
Interest expense, net	(46)	(45)	(92)	(92)
Earnings before income taxes	83	55	341	274
Income tax expense	33	20	127	100
Net income	50	35	214	174
Less net income attributable to the noncontrolling interest	1	1	11	10
Net income attributable to AGL Resources Inc.	$49	$34	$203	$164
Per common share data				
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	$0.41	$0.28	$1.72	$1.40
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	$0.41	$0.28	$1.72	$1.40
Cash dividends declared per common share	$0.47	$0.46	$0.94	$0.82
Weighted average number of common shares outstanding				
Basic	117.8	116.9	117.6	116.8
Diluted	118.2	117.2	117.9	117.1

See Notes to Condensed Consolidated Financial Statements (Unaudited).

Glossary of Key Terms

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

	Three months ended June 30,		Six months ended June 30,	
In millions	2013	2012	2013	2012
Net income	$50	$35	$214	$174
Other comprehensive income (loss), net of tax				
Retirement benefit plans				
Reclassification of actuarial losses to net benefit cost (net of income tax of $3 and $5 for the three and six months ended June 30, 2013, and $3 and $4 for the three and six months ended June 30, 2012)	4	7	8	8
Reclassification of prior service credits to net benefit cost (net of income tax of $1 for the six months ended June 30, 2013)	-	-	(1)	-
Retirement benefit plans	4	7	7	8
Cash flow hedges, net of tax				
Net derivative instrument (losses) gains arising during the period (net of income tax of $1 for the three months ended June 30, 2013, and $3 and $1 for the three and six months ended June 30, 2012)	(1)	4	1	2
Reclassification of realized derivative instrument (gains) losses to net income (net of income tax of $1 for the six months ended June 30, 2013)	(1)	-	1	-
Cash flow hedges, net	(2)	4	2	2
Other comprehensive income, net of tax	2	11	9	10
Comprehensive income	52	46	223	184
Less comprehensive income attributable to noncontrolling interest	1	1	11	10
Comprehensive income attributable to AGL Resources Inc.	$51	$45	$212	$174

See Notes to Condensed Consolidated Financial Statements (Unaudited).

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

	AGL Resources Inc. Shareholders							
	Common stock		Additional paid-in	Retained	Accumulated other comprehensive	Treasury	Noncontrolling	
In millions, except per share amounts	Shares	Amount	capital	earnings	loss	shares	interest	Total
Balance as of December 31, 2011	117.0	$ 586	$ 1,989	$ 967	$ (217)	$ (7)	$ 21	$ 3,339
Net income	-	-	-	164	-	-	10	174
Other comprehensive income	-	-	-	-	10	-	-	10
Dividends on common stock ($0.82 per share)	-	-	-	(96)	-	-	-	(96)
Distributions to noncontrolling interest	-	-	-	-	-	-	(14)	(14)
Stock issued, dividend reinvestment plan	0.5	3	9	-	-	(1)	-	11
Stock-based compensation expense (net of tax)	-	-	5	-	-	-	-	5
Balance as of June 30, 2012	117.5	$ 589	$ 2,003	$ 1,035	$ (207)	$ (8)	$ 17	$ 3,429

	AGL Resources Inc. Shareholders							
	Common stock		Additional paid-in	Retained	Accumulated other comprehensive	Treasury	Noncontrolling	
In millions, except per share amounts	Shares	Amount	capital	earnings	loss	shares	interest	Total
Balance as of December 31, 2012	117.9	$ 590	$ 2,014	$ 1,035	$ (218)	$ (8)	$ 22	$ 3,435
Net income	-	-	-	203	-	-	11	214
Other comprehensive income	-	-	-	-	9	-	-	9
Dividends on common stock ($0.94 per share)	-	-	-	(111)	-	-	-	(111)

Distributions to noncontrolling interest	-	-	-	-	-	-	(17)	(17)
Stock granted, share-based compensation, net of forfeitures	-	-	(6)		-	-	-	(6)
Stock issued, dividend reinvestment plans	0.1	1	5	-	-	-	-	6
Stock issued, share-based compensation, net of forfeitures	0.6	3	18	-	-	-	-	21
Stock-based compensation expense (net of tax)	-	-	4	-	-	-	-	4
Balance as of June 30, 2013	118.6	$ 594	$ 2,035	$ 1,127	$ (209)	$ (8)	$ 16	$ 3,555

See Notes to Condensed Consolidated Financial Statements (Unaudited).

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

	Six months ended June 30,	
In millions	2013	2012
Cash flows from operating activities		
Net income	$214	$174
Adjustments to reconcile net income to net cash flow provided by operating activities		
Depreciation and amortization	216	206
Change in derivative instrument assets and liabilities	14	18
Deferred income taxes	(18)	56
Gain on sale of Compass Energy	(11)	-
Changes in certain assets and liabilities		
Receivables, other than energy marketing	267	367
Inventories, net of temporary LIFO liquidation	262	242
Energy marketing receivables and trade payables, net	86	53
Prepaid taxes	57	33
Accrued natural gas costs	40	20
Trade payables, other than energy marketing	(15)	(34)
Other - net	49	(45)
Net cash flow provided by operating activities	1,161	1,090
Cash flows from investing activities		
Expenditures for property, plant and equipment	(318)	(350)
Acquisitions of assets	(122)	-
Disposition of assets	12	-
Other	15	(8)
Net cash flow used in investing activities	(413)	(358)
Cash flows from financing activities		
Issuance of senior notes	494	-
Net payments and borrowings of short-term debt	(857)	(590)
Payment of senior notes	(225)	-
Dividends paid on common shares	(111)	(96)
Distribution to noncontrolling interest	(17)	(14)
Other	21	(14)
Net cash flow used in financing activities	(695)	(714)
Net increase in cash and cash equivalents	53	18
Cash and cash equivalents at beginning of period	131	69
Cash and cash equivalents at end of period	$184	$87
Cash paid during the period for		
Interest	$89	$86
Income taxes	$60	$4
Non cash financing transaction		
Refinancing of gas facility revenue bonds	$200	$-

See Notes to Condensed Consolidated Financial Statements (Unaudited).

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

Note 1 - Organization and Basis of Presentation

General

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

The December 31, 2012 Condensed Consolidated 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 and regulations of the SEC. In accordance with such rules and regulations, we have condensed or omitted certain information and notes normally included in financial statements prepared in conformity with GAAP. Our unaudited 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. These unaudited Condensed Consolidated Financial Statements should be read in conjunction with our Consolidated Financial Statements and related notes included in Item 8 of our 2012 Form 10-K.

Due to the seasonal nature of our business and other factors, our results of operations and our financial condition for the periods presented are not necessarily indicative of the results of operations and financial condition to be expected for or as of any other period.

Basis of Presentation

Our unaudited Condensed Consolidated Financial Statements include our accounts, the accounts of our wholly owned subsidiaries, the accounts of our majority-owned and controlled subsidiaries and the accounts of our consolidated VIE, for which we are the primary beneficiary. For unconsolidated entities that we do not control, but exercise significant influence over, we use the equity method of accounting and our proportionate share of income or loss is recorded on the unaudited Condensed Consolidated Statements of Income. See Note 8 for additional information. We have eliminated intercompany profits and transactions in consolidation except for intercompany profits where recovery of such amounts is probable under the affiliates’ rate regulation process.

Certain amounts from prior periods have been reclassified and revised to conform to the current period presentation. The reclassifications and revisions had no material impact on prior periods.

Note 2 - Significant Accounting Policies and Methods of Application

Our accounting policies are described in Note 2 to our Consolidated Financial Statements and related notes included in Item 8 of our 2012 Form 10-K. There were no significant changes to our accounting policies during the six months ended June 30, 2013.

Use of Accounting Estimates

The preparation of our financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures. Our estimates are based on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Our estimates may involve complex situations requiring a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our financial statements. The most significant estimates relate to our regulatory infrastructure program accruals, environmental remediation accruals, uncollectible accounts and other allowances for contingent losses, goodwill and other intangible assets, retirement plan benefit obligations, derivative and hedging activities and provisions for income taxes. We evaluate our estimates on an ongoing basis and our actual results could differ from our estimates.

Cash, Cash Equivalents and Cash Investments

Our cash and cash equivalents consist primarily of cash on deposit, money market accounts and certificates of deposit held by domestic subsidiaries with original maturities of three months or less. As of June 30, 2013 and 2012, and December 31, 2012, we had $79 million, $76 million and $80 million, respectively, of cash and short-term investments held by Tropical Shipping. This cash and investments are not available for use by our other operations unless we repatriate a portion of Tropical Shipping’s earnings in the form of a dividend, and pay a significant amount of United States income tax. See Note 12 to our Consolidated Financial Statements included in Item 8 of our 2012 Form 10-K for additional information on our income taxes.

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Inventories

Except for Nicor Gas, our gas inventories and the inventories we hold for Marketers are carried at cost on a WACOG basis. In Georgia's competitive environment, Marketers sell natural gas to firm end-use customers at market-based prices. Part of the unbundling process, which resulted from deregulation and provides this competitive environment, is the assignment to Marketers of certain pipeline services that Atlanta Gas Light has under contract. On a monthly basis, Atlanta Gas Light assigns the majority of the pipeline storage services that it has under contract to Marketers, along with a corresponding amount of inventory. Atlanta Gas Light also retains and manages a portion of its pipeline storage assets and related natural gas inventories for system balancing and to serve system demand. See Note 9 for information regarding a regulatory filing by Atlanta Gas Light related to gas inventory.

Nicor Gas' inventory is carried at cost on a LIFO basis. Inventory decrements occurring during interim periods that are expected to be restored prior to year-end are charged to cost of goods sold at the estimated annual replacement cost, and the difference between this cost and the actual liquidated LIFO layer cost is recorded as a temporary LIFO inventory liquidation. Any temporary LIFO liquidation is included as a current liability in our unaudited Condensed Consolidated Statements of Financial Position. Interim inventory decrements that are not expected to be restored prior to year-end are charged to cost of goods sold at the actual LIFO cost of the layers liquidated. The inventory decrement as of June 30, 2013 is expected to be restored prior to year-end. The inventory decrement as of June 30, 2012 was restored prior to December 31, 2012.

Our retail operations, wholesale services and midstream operations segments evaluate the weighted average cost of their natural gas inventories against market prices to determine whether any declines in market prices below the WACOG are other-than-temporary. For any declines considered to be other-than-temporary, we record adjustments to reduce the weighted average cost of the natural gas inventory to market price. For the periods presented, we recorded LOCOM adjustments to cost of goods sold in the following amounts to reduce the value of our inventories to market value.

	Three months ended June 30,		Six months ended June 30,	
In millions	2013	2012	2013	2012
Retail operations	$ -	$ -	$ -	$ 3
Wholesale services	8	-	8	18
Midstream operations	-	-	-	1

Energy Marketing Receivables and Payables

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

Our wholesale services segment has trade and credit contracts that contain 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. To date, our credit ratings have exceeded the minimum requirements. As of June 30, 2013, December 31, 2012 and June 30, 2012, the collateral that wholesale services would have been required to post if our credit ratings had been downgraded to non-investment grade status

would not have had a material impact to our consolidated results of operations, cash flows or financial position. If such collateral were not posted, wholesale services' ability to continue transacting business with these counterparties would be negatively impacted.

Fair Value Measurements

We have financial and nonfinancial assets and liabilities subject to fair value measures. The financial assets and liabilities measured and carried at fair value include cash and cash equivalents, and derivative assets and liabilities. The carrying values of receivables, short and long-term investments, accounts payable, short-term debt, other current assets and liabilities, and accrued interest approximate fair value. Our nonfinancial assets and liabilities include pension and other retirement benefits, which are presented in Note 4 to our Consolidated Financial Statements and in related notes included in Item 8 of our 2012 Form 10-K.

As defined in the authoritative guidance related to fair value measurements and disclosures, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in valuing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the market approach for recurring fair value measurements to utilize the best available information. Accordingly, we use valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We classify fair value balances based on the observance of those inputs in accordance with the fair value hierarchy.

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Derivative Instruments

The fair value of the natural gas derivative instruments that we use to manage exposures arising from changing natural gas prices reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains or losses on open contracts. We use external market quotes and indices to value substantially all of our derivative instruments. See Note 3 and Note 4 for additional derivative disclosures.

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

On June 28, 2013, we entered into an OTC weather derivative to reduce the risk of lower operating margins as a result of significantly warmer-than-normal weather in Illinois during the fourth quarter of 2013. The weather derivative is based on fourth quarter 2013 Heating Degree Days at Chicago Midway International Airport. This is a cash-settled option and we retain substantially all upside potential should the fourth quarter be colder-than-normal, but our operating margin will be largely protected in the event of significantly warmer-than-normal weather.

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

Retail Operations We have designated a portion of our derivative instruments, consisting of financial swaps to manage the risk associated with forecasted natural gas purchases and sales, as cash flow hedges. We record derivative gains or losses arising from cash flow hedges in OCI and reclassify them into earnings in the same period that the underlying hedged item is recognized in earnings.

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

We also enter into weather derivative contracts as economic hedges of operating margins in the event of warmer-than-normal weather in the Heating Season. Exchange-traded options are carried at fair value, with changes reflected in operating revenues. Non exchange-traded options are accounted for using the intrinsic value method and do not qualify for hedge accounting designation. Changes in the intrinsic value for non exchange-traded contracts are also reflected in operating revenues in our unaudited Condensed Consolidated Statements of Income.

Wholesale Services We purchase natural gas for storage when the current market price we pay to buy and transport natural gas plus the cost to store and finance the natural gas is less than the market price we can receive in the future, resulting in a positive net operating margin. We use NYMEX futures and OTC contracts to sell natural gas at that future price to substantially lock in the operating margin we ultimately will realize when the stored natural gas is sold. We also enter into transactions to secure transportation capacity between two delivery points in order to serve our customers and various markets. We use NYMEX futures and OTC contracts to capture the price differential or spread

between the locations served by the capacity in order to substantially lock in the operating margin we will ultimately realize when we physically flow natural gas between the two delivery points. These contracts generally meet the definition of derivatives and are carried at fair value, with changes in fair value recorded in operating revenues in the period of change. These contracts are not designated as hedges for accounting purposes.

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The purchase, transportation, storage and sale of natural gas are accounted for on a weighted average cost or accrual basis, as appropriate, rather than on the fair value basis we utilize for the derivatives used to mitigate the natural gas price risk associated with our storage and transportation portfolio. We incur monthly demand charges for the contracted storage and transportation capacity, and payments associated with asset management agreements, and recognize these demand charges and payments in the period they are incurred. This difference in accounting can result in volatility in our reported earnings, even though the economic margin is essentially unchanged from the dates the transactions were consummated.

Regulatory Assets and Liabilities

We account for the financial effects of regulation in accordance with authoritative guidance related to regulated entities whose rates are designed to recover the costs of providing service. In accordance with this guidance, incurred costs and estimated future expenditures that otherwise would be charged to expense in the current period are capitalized as regulatory assets when it is probable that such costs or expenditures will be recovered in rates in the future. Similarly, we recognize regulatory liabilities when it is probable that regulators will require customer refunds through future rates or when revenue is collected from customers for estimated expenditures that have not yet been incurred. Generally, regulatory assets are amortized into expense and regulatory liabilities are amortized into income over the period authorized by the regulatory commissions. We are not aware of any evidence that these costs will not be recoverable through either rate riders or base rates, and we believe that we will be able to recover such costs consistent with our historical recoveries. In the event that the provisions of authoritative guidance related to regulated operations were no longer applicable, we would recognize a write-off of regulatory assets that would result in a charge to net income and be classified as an extraordinary item.

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

In millions	June 30, 2013	December 31, 2012	June 30, 2012
Regulatory assets			
Recoverable regulatory infrastructure program costs	$ 46	$ 47	$ 47
Recoverable environmental remediation costs	27	38	30
Recoverable pension and retiree welfare benefit costs	19	19	27
Other regulatory assets	28	41	42
Total regulatory assets - current	120	145	146
Recoverable environmental remediation costs	458	438	428
Recoverable pension and retiree welfare benefit costs	188	196	232
Recoverable regulatory infrastructure program costs	116	167	268
Long-term debt fair value adjustment	86	90	94
Other regulatory assets	50	53	61
Total regulatory assets - long-term	898	944	1,083
Total regulatory assets	$ 1,018	$ 1,089	$ 1,229
Regulatory liabilities			
Accrued natural gas costs	$ 130	$ 93	$ 73
Bad debt rider	39	37	31
Accumulated removal costs	17	16	14

Other regulatory liabilities	30	15	19
Total regulatory liabilities - current	216	161	137
Accumulated removal costs	1,431	1,393	1,366
Unamortized investment tax credit	27	29	31
Regulatory income tax liability	26	27	25
Bad debt rider	20	17	18
Other regulatory liabilities	6	11	13
Total regulatory liabilities - long-term	1,510	1,477	1,453
Total regulatory liabilities	$ 1,726	$ 1,638	$ 1,590

There have been no significant new types of regulatory assets or liabilities beyond those discussed in Note 2 to our Consolidated Financial Statements and related notes in Item 8 of our 2012 Form 10-K.

Other Income

Our other income is detailed in the following table for the periods presented. For more information on our equity investment income, see Note 8.

	Three months ended June 30,		Six months ended June 30,	
In millions	2013	2012	2013	2012
Equity investment income (1)	$ 2	$ 5	$ 5	$ 8
Allowance for funds used during construction (AFUDC) - equity	3	1	6	2
Other, net	2	3	1	3
Total other income	$ 7	$ 9	$ 12	$ 13

(1) Primarily relates to our investment in Triton. See Note 8 for additional information.

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Earnings Per Common Share

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

We derive our potentially dilutive common shares by calculating the number of shares issuable under restricted stock, restricted stock units and stock options. The vesting of certain shares of the restricted stock and restricted stock units depends on the satisfaction of defined performance criteria. The future issuance of shares underlying the outstanding stock options depends on whether the market price of the common shares underlying the options exceeds the respective exercise prices of the stock options.

The following table shows the calculation of our diluted shares attributable to AGL Resources Inc. common shareholders for the periods presented, if performance units currently earned under the plan ultimately vest and if stock options currently exercisable at prices below the average market prices are exercised.

	Three months ended June 30,		Six months ended June 30,	
In millions (except per share amounts)	2013	2012	2013	2012
Net income attributable to AGL Resources Inc.	$ 49	$ 34	$ 203	$ 164
Denominator:				
Basic weighted average number of shares outstanding (1)	117.8	116.9	117.6	116.8
Effect of dilutive securities	0.4	0.3	0.3	0.3
Diluted weighted average number of shares outstanding	118.2	117.2	117.9	117.1
Earnings per share:				
Basic	$ 0.41	$ 0.28	$ 1.72	$ 1.40
Diluted	$ 0.41	$ 0.28	$ 1.72	$ 1.40

(1) Daily weighted average shares outstanding.

Acquisitions

On January 31, 2013, our retail operations segment acquired approximately 500,000 service plans and certain other assets from NiSource Inc. for $120 million, plus $2 million of working capital. These service plans provide home warranty protection solutions and energy efficiency leasing solutions for residential and small business utility customers and complement the retail services business acquired in the Nicor merger. The preliminary allocation of the purchase price is as follows:

In millions	
Current assets	$ 5
PP&E	11
Goodwill	46
Intangible assets	64

Current liabilities	(4)
Total purchase price	$ 122

Intangible assets related to this acquisition are primarily customer relationships of $47 million and trade names of $17 million. The amortization periods are estimated to be 14 years for customer relationships and 10 years for trade names.

On June 30, 2013, our retail operations segment acquired approximately 33,000 residential and commercial relationships in Illinois for $32 million. These customer relationships have been recorded as an intangible asset and are expected to be amortized on a straight-line basis over an estimated period of 12 to 15 years.

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Sale of Compass Energy

On May 1, 2013, we sold Compass Energy, a non-regulated retail natural gas business supplying commercial and industrial customers. Compass Energy was part of our wholesale services segment. Upon completion of this transaction, we received an initial cash payment of $12 million, which resulted in an $11 million pre-tax gain. Under the terms of the purchase and sale agreement, we are eligible to receive contingent cash consideration up to $8 million with a guaranteed minimum receipt of $3 million. The amount of the contingent cash consideration will be paid over a five-year earn out period based upon the financial performance of Compass Energy.

Accounting Developments

On January 1, 2013, we adopted ASU 2011-11, Disclosures about Offsetting Assets and Liabilities and ASU 2013-01, Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities, which require disclosures about offsetting and related arrangements in order to help financial statement users better understand the effect of those arrangements on our financial position. This guidance had no impact on our unaudited Condensed Consolidated Financial Statements. See Note 4 for additional disclosures about our offsetting of derivative assets and liabilities.

On January 1, 2013, we adopted ASU 2013-02, Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income, which requires enhanced disclosures of amounts reclassified out of accumulated other comprehensive income by component. This guidance had no impact on our unaudited Condensed Consolidated Financial Statements. See Note 7 for additional disclosures relating to accumulated other comprehensive income.

Note 3 - Fair Value Measurements

The methods used to determine the fair values of our assets and liabilities are described within Note 2.

Derivative Instruments

The following table summarizes, by level within the fair value hierarchy, our derivative assets and liabilities that were carried at fair value on a recurring basis in our unaudited Consolidated Statements of Financial Position as of the dates presented. See Note 4 for additional derivative instrument information.

	Recurring fair values - Derivative instruments					
	June 30, 2013		December 31, 2012		June 30, 2012	
In millions	Assets (1)	Liabilities	Assets (1)	Liabilities	Assets (1)	Liabilities
Natural gas derivatives						
Quoted prices in active markets (Level 1)	$ 4	$ (51)	$ 8	$ (45)	$ 9	$ (103)
Significant other observable inputs (Level 2)	78	(35)	96	(30)	148	(48)
Netting of cash collateral	47	47	33	36	52	85
Total carrying value (2) (3)	$ 129	$ (39)	$ 137	$ (39)	$ 209	$ (66)
Interest rate derivatives						
	$ -	$ -	$ 3	$ -	$ 17	$ -

Significant other
observable inputs
(Level 2)

(1) Balances of $1 million of premium at June 30, 2013 and $4 million at December 31, 2012 associated with weather derivatives have been excluded, as they are not material and some are accounted for based on intrinsic value.

(2) There were no material unobservable inputs (Level 3) for any of the dates presented.

(3) There were no material transfers between Level 1, Level 2 or Level 3 for any of the dates presented.

Money Market Funds

The fair values of our money market funds were recorded within short-term investments as follows:

In millions	At June 30, 2013	At December 31, 2012	At June 30, 2012
Money market funds (1)	$ 48	$ 66	$ 76

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

Debt

Our long-term debt is recorded at amortized cost, with the exception of Nicor Gas' first mortgage bonds, which were recorded at their acquisition date fair value. The fair value adjustment of Nicor Gas' first mortgage bonds is being amortized over the lives of the bonds. We estimate the fair value of our debt using a discounted cash flow technique that incorporates a market interest yield curve with adjustments for duration, optionality and risk profile. The following table presents the amortized cost and fair value of our long-term debt as of the following dates.

In millions	June 30, 2013	December 31, 2012	June 30, 2012
Long-term debt amortized cost	$ 3,819	$ 3,553	$ 3,565
Long-term debt fair value (1)	4,070	4,057	4,043

(1) Fair value determined using Level 2 inputs.

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Note 4 - Derivative Instruments

A description of our objectives and strategies for using derivative instruments, related accounting policies and methods used to determine their fair values are described in Note 2. See Note 3 for additional fair value disclosures.

Certain of our derivative instruments contain credit-risk-related or other contingent features that could require us to post collateral in the normal course of business when our financial instruments are in net liability positions. As of June 30, 2013, for agreements with such features, derivative instruments with liability fair values totaled $39 million, for which we had posted no collateral to our counterparties. In addition, our energy marketing receivables and payables, which also have credit-risk-related or other contingent features, are discussed in Note 2. Our derivative instrument activities are included within operating cash flows as an adjustment to net income of $14 million and $18 million for the six months ended June 30, 2013 and 2012, respectively. See Note 3 for additional derivative instrument information. The following table summarizes the various ways in which we account for our derivative instruments and the impact on our unaudited Condensed Consolidated Financial Statements.

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

Distribution Operations

The following amounts represent net realized gains (losses) related to hedging natural gas costs for the periods presented.

	Three months ended June 30,		Six months ended June 30,	
In millions	2013	2012	2013	2012
Nicor Gas	$ 9	$ (25)	$ 8	$ (26)
Elizabethtown Gas	(1)	(7)	(4)	(16)

Quantitative Disclosures Related to Derivative Instruments

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

In Bcf (1)	June 30, 2013 (2)	December 31, 2012	June 30, 2012
Hedge designation			
Cash flow hedges	3	6	7
Not designated as hedges	221	96	47
Total hedges	224	102	54
Hedge position			
Short position	(2,311)	(1,955)	(2,018)
Long position	2,535	2,057	2,072
Net long position	224	102	54

(1) Volumes related to Nicor Gas exclude variable-priced contracts, which are accounted for as derivatives, but whose fair values are not directly impacted by changes in commodity prices.

(2) Approximately 98% of these contracts have durations of two years or less and the remaining 2% expire between 2 and 6 years.

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Derivative Instruments in our Unaudited Condensed Consolidated Statements of Financial Position

The following table presents the fair values and unaudited Condensed Consolidated Statements of Financial Position classifications of our derivative instruments as of the dates presented.

		June 30, 2013		December 31, 2012		June 30, 2012		December 31, 2011	
In millions	Classification (1) (2)	Assets	Liabilities	Assets	Liabilities	Assets	Liabilities	Assets	Liabilities
Designated as cash flow hedges and fair value hedges									
Natural gas contracts	Current	$ 2	$ (1)	$ 1	$ (2)	$ 6	$ (7)	$ 9	$ (12)
Natural gas contracts	Long-term	-	-	3	-	-	-	-	-
Interest rate swap agreements	Long-term	-	-	-	-	17	-	13	(13)
Total		2	(1)	4	(2)	23	(7)	22	(25)
Not designated as cash flow hedges									
Natural gas contracts	Current	456	(445)	394	(355)	493	(489)	706	(689)
Natural gas contracts	Long-term	124	(139)	45	(50)	69	(66)	133	(116)
Total		580	(584)	439	(405)	562	(555)	839	(805)
Gross amount of recognized assets and liabilities		582	(585)	443	(407)	585	(562)	861	(830)
Gross amounts offset in our unaudited Condensed Consolidated Statements of Financial Position		(452)	546	(299)	368	(359)	496	(573)	720
Net amounts of assets and liabilities presented in our unaudited Condensed Consolidated Statements of Financial Position		$ 130	$ (39)	$ 144	$ (39)	$ 226	$ (66)	$ 288	$ (110)

(1) The gross amounts of recognized assets and liabilities are netted within our unaudited Condensed Consolidated Statements of Financial Position to the extent that we have netting arrangements with the counterparties.

(2) As required by the authoritative guidance related to derivatives and hedging, the gross amounts of recognized assets and liabilities above do not include cash collateral held on deposit in broker margin accounts of $94 million as of June 30, 2013, $69 million as of December 31, 2012, $137 million as of June 30, 2012 and $147 million as of December 31, 2011. Cash collateral is included in the “Gross amounts offset in our unaudited Condensed Consolidated Statements of Financial Position” line of this table.

Derivative Instruments Impacts in our Unaudited Condensed Consolidated Statements of Income

The following table presents the amounts of our derivative instruments in our unaudited Condensed Consolidated Statements of Income for the periods presented.

	Three months ended June 30,		Six months ended June 30,	
In millions	2013	2012	2013	2012
Designated as cash flow hedges				
Natural gas contracts - gain reclassified from OCI into cost of goods sold	$ 1	$ 3	$ 1	$ 4
Natural gas contracts – gain reclassified from OCI into operation and maintenance expense	-	1	-	1
Natural gas contracts – loss recognized in OCI (effective portion)	-	(1)	-	-
Interest rate swaps - ineffectiveness recorded as an offset to interest expense	-	(1)	(3)	(3)
Not designated as hedges				
Natural gas contracts - net fair value adjustments recorded in operating revenues (1)	22	15	(2)	19
Natural gas contracts - net fair value adjustments recorded in cost of goods sold (2)	(1)	(1)	(1)	(3)
Total gains (losses) on derivative instruments	$ 22	$ 16	$ (5)	$ 18

(1) Associated with the fair value of existing derivative instruments at June 30, 2013 and 2012.

(2) Excludes losses recorded in operating revenues or cost of goods sold associated with weather derivatives of $3 million for the six months ended June 30, 2013 and gains of $14 million for the six months ended June 30, 2012.

Any amounts recognized in operating income, related to ineffectiveness or due to a forecasted transaction that is no longer expected to occur were immaterial for the six months ended June 30, 2013 and 2012.

Our expected pre-tax net loss to be reclassified from OCI and recognized in cost of goods sold, operation and maintenance expenses, operating revenues and interest expense in our unaudited Condensed Consolidated Statements of Income over the next 12 months is $1 million. These pre-tax deferred gains and losses are recorded in OCI related to natural gas derivative contracts associated with retail operations and Nicor Gas and interest rate swaps with AGL Capital. The expected losses are based upon the fair values of these financial instruments at June 30, 2013.

There have been no other significant changes to our derivative instruments, as described in Note 2 and Note 4 to our Consolidated Financial Statements and related notes included in Item 8 of our 2012 Form 10-K.

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Note 5 - Employee Benefit Plans

Pension Benefits

On December 31, 2012, the AGL Resources Inc. Retirement Plan (AGL Plan), the Nicor Companies Pension and Retirement Plan (Nicor Plan) and the Employees' Retirement Plan of NUI Corporation (NUI Plan) were merged with, and into, the AGL Plan. The eligibility and benefit terms for participants under the Nicor Plan and the NUI Plan were not changed as a result of the plan merger. The AGL Plan is described in Note 6 to our Consolidated Financial Statements and related notes included in Item 8 of our 2012 Form 10-K.

Following are the components of our pension benefit costs for the periods indicated.

	Three months ended June 30,		Six months ended June 30,	
In millions	2013	2012	2013	2012
Service cost	$ 7	$ 7	$ 15	$ 14
Interest cost	11	11	21	22
Expected return on plan assets	(15)	(16)	(31)	(32)
Net amortization of prior service cost	(1)	-	(1)	(1)
Recognized actuarial loss	9	8	17	17
Net periodic pension benefit cost	$ 11	$ 10	$ 21	$ 20

Retiree Welfare Benefits

On December 31, 2012, the Nicor Gas Welfare Benefit Plan (Nicor Welfare Plan) was terminated and as of January 1, 2013, all participants under that plan became eligible to participate in the Health and Welfare Plan for Retirees and Inactive Employees of AGL Resources Inc. (AGL Welfare Plan). This change in plan participation eligibility did not affect the benefit terms under the predecessor plans. The Nicor Welfare Plan benefits are now being offered to such participants under the AGL Welfare Plan. The benefits of the AGL Welfare Plan are described in Note 6 to our Consolidated Financial Statements and related notes included in Item 8 of our 2012 Form 10-K.

Following are the components of our retiree welfare benefit costs for the periods indicated.

	Three months ended June 30,		Six months ended June 30,	
In millions	2013	2012	2013	2012
Service cost	$ -	$ 1	$ 1	$ 2
Interest cost	4	4	7	8
Expected return on plan assets	(2)	(2)	(3)	(3)
Net amortization of prior service cost	(1)	-	(2)	(1)
Recognized actuarial loss	2	2	4	5
Net periodic welfare benefit cost	$ 3	$ 5	$ 7	$ 11

Capitalized Costs

Net pension benefit and net welfare benefit costs are included in operation and maintenance expense, except for a portion that is capitalized as a cost of constructing natural gas distribution facilities.

Contributions

Our employees generally do not contribute to these pension and retiree welfare plans. We fund the qualified pension plan by contributing at least the minimum amounts required by applicable regulations and as recommended by our

actuary. However, we may contribute in excess of the minimum required amounts.

As a result of merging the pension plans, there were no contributions required during the six months ended June 30, 2013. We contributed a combined $24 million to the AGL Plan and the NUI Plan during the same period last year. For more information on our pension plans, see Note 6 to our Consolidated Financial Statements and related notes included in Item 8 of our 2012 Form 10-K.

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Note 6 - Debt and Credit Facilities

The following table provides maturity dates, year-to-date weighted average interest rates and amounts outstanding for our various debt securities and facilities that are included in our unaudited Condensed Consolidated Statements of Financial Position. For additional information on our debt, see Note 8 in our Consolidated Financial Statements and related notes in Item 8 of our 2012 Form 10-K.

		June 30, 2013			June 30, 2012		
Dollars in millions	Year(s) due	Weighted average interest rate (1)	Outstanding	Outstanding at December 31, 2012	Weighted average interest rate (1)	Outstanding
Short-term debt						
Commercial paper - AGL Capital (2)	2013	0.5 %	$ 521	$ 1,063	0.5 %	$ 731
Commercial paper - Nicor Gas	2013	0.4	-	314	0.5	-
Total short-term debt		0.5	521	1,377	0.5	731
Current portion of long-term debt and capital leases						
Current portion of long-term debt	2013	4.5	-	225	4.7	230
Current portion of capital leases	2013	5.0	-	1	4.9	1
Total current portion of long-term debt and capital leases		4.5 %	$ -	$ 226	4.7 %	$ 231
Long-term debt - excluding current portion						
Senior notes	2015-2043	5.1 %	$ 2,825	$ 2,325	5.1 %	$ 2,325
First mortgage bonds	2016-2038	5.6	500	500	5.6	500
Gas facility revenue bonds	2022-2033	0.5	200	200	1.2	200
Medium-term notes	2017-2027	7.8	181	181	7.8	181
Total principal long-term debt		4.9	3,706	3,206	5.0	3,206
Fair value adjustment of long-term debt (3)	2016-2038	n/a	97	103	n/a	110
Unamortized debt premium, net	n/a	n/a	16	18	n/a	18
Total non-principal long-term debt		n/a	113	121	n/a	128
Total long-term debt			$ 3,819	$ 3,327		$ 3,334
Total debt			$ 4,340	$ 4,930		$ 4,296

(1) Interest rates are calculated based on the daily weighted average balance outstanding for the six months ended June 30.

(2) As of June 30, 2013, the weighted average interest rate on AGL Capital’s commercial paper borrowings was 0.4%.

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

Long-Term Debt

On May 16, 2013, we issued $500 million in 30-year senior notes with a fixed interest rate of 4.4%. The net proceeds were used to repay a portion of AGL Capital’s commercial paper, including $225 million we borrowed to redeem our

senior notes that matured on April 15, 2013. We fully and unconditionally guarantee all debt issued by AGL Capital.

During the first quarter of 2013, we refinanced $200 million of our outstanding tax-exempt gas facility revenue bonds, $180 million of which were previously issued by the New Jersey Economic Development Authority and $20 million of which were previously issued by Brevard County, Florida. The refinancing involved a combination of the issuance of $60 million of refunding bonds to, and the purchase of $140 million of existing bonds by, a syndicate of banks. Our relationship with the syndicate of banks regarding the bonds is governed by an agreement that contains representations, warranties, covenants and default provisions consistent with those contained in similar financing documents of ours. All of the bonds are floating-rate instruments. AGL Resources had no cash receipts or payments in connection with the refinancing. The letters of credit providing credit support for the outstanding revenue bonds along with other related agreements were terminated as a result of the refinancing.

Interest Rate Swaps

On April 4, 2013, we entered into two ten-year, $50 million fixed-rate forward-starting interest rate swaps to hedge any potential interest rate volatility prior to our issuance of senior notes in the second quarter 2013. The average interest rate on these swaps was 1.98%. Including existing forward-starting interest rate swap hedges, which were executed last year, we had fixed-rate swaps totaling $300 million in notional value at an average interest rate of 1.85%. We designated the forward-starting interest rate swaps as cash flow hedges of our second quarter 2013 senior note issuance. The interest rate swaps were settled on May 16, 2013, the senior note issuance date, at which time we received $6 million in proceeds. The $6 million will be amortized to reduce interest expense over the first 10 years of the 30-year senior notes.

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Financial and Non-Financial Covenants

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

	June 30, 2013		December 31, 2012		June 30, 2012	
AGL Credit Facility	54	%	58	%	54	%
Nicor Gas Credit Facility	43		55		43	

The credit facilities contain certain non-financial covenants that, among other things, restrict liens and encumbrances, loans and investments, acquisitions, dividends and other restricted payments, asset dispositions, mergers and consolidations and other matters customarily restricted in such agreements.

Default Provisions

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

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

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

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Note 7 - Equity

Our other comprehensive income amounts are aggregated within our accumulated other comprehensive loss. The following table provides changes in the components of our accumulated other comprehensive loss balance, net of the related income tax effects.

	2013			2012		
In millions (1)	Cash flow hedges	Retirement benefit plans	Total	Cash flow hedges	Retirement benefit plans	Total
For the three months ending June 30						
Balance as of March 31	$ (2)	$ (209)	$ (211)	$ (12)	$ (206)	$ (218)
Other comprehensive income, before reclassifications	(1)	-	(1)	4	-	4
Amounts reclassified from accumulated other comprehensive income	(1)	4	3	-	7	7
Net current-period other comprehensive (loss) income	(2)	4	2	4	7	11
Balance as of June 30	$ (4)	$ (205)	$ (209)	$ (8)	$ (199)	$ (207)
For the six months ending June 30						
Balance as of December 31, prior year	$ (6)	$ (212)	$ (218)	$ (10)	$ (207)	$ (217)
Other comprehensive income, before reclassifications	1	-	1	2	-	2
Amounts reclassified from accumulated other comprehensive income	1	7	8	-	8	8
Net current-period other comprehensive income	2	7	9	2	8	10
Balance as of June 30	$ (4)	$ (205)	$ (209)	$ (8)	$ (199)	$ (207)

(1) All amounts are net of income taxes. Amounts in parentheses indicate debits to accumulated other comprehensive loss.

The following table provides details of the reclassifications out of accumulated other comprehensive loss for the periods presented, and the ultimate impact on net income.

	Amount reclassified from accumulated other comprehensive loss (1)				Affected line item in the income statement
	Three months ending June 30,		Six months ending June 30,		
In millions	2013	2012	2013	2012	
Cash flow hedges					
Interest rate contracts	$1	$-	$(2)	$-	Interest expense, net

Income tax benefit	-	-	1	-	
Total cash flow hedges	1	-	(1)	-	
Retirement benefit plan amortization of					
Actuarial losses	(7)	(10)	(13)	(12)	See (2), below
Prior service credits	-	-	2	-	See (2), below
Total before income tax	(7)	(10)	(11)	(12)	
Income tax benefit	3	3	4	4	
Total retirement benefit plans	(4)	(7)	(7)	(8)	
Total reclassification for the period	$(3)	$(7)	$(8)	$(8)	

(1) Amounts in parentheses indicate debits, or reductions, to profit/loss and credits to accumulated other comprehensive loss. Except for retirement benefit plan amounts, the profit/loss impacts are immediate.

(2) Amortization of these accumulated other comprehensive loss components is included in the computation of net periodic benefit cost. See Note 5 for additional details about net periodic benefit cost.

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Note 8 - Non-Wholly Owned Entities

Variable Interest Entities

On a quarterly basis, we evaluate all of our ownership interests to determine if they represent a VIE as defined by the authoritative accounting guidance on consolidation, and if so, which party is the primary beneficiary. We have determined that SouthStar, a joint venture owned 85% by us and 15% by Piedmont, is our only VIE for which we are the primary beneficiary, which requires us to consolidate its assets, liabilities and statements of income. See Note 10 to our Consolidated Financial Statements and related notes included in Item 8 of our 2012 Form 10-K. Earnings from SouthStar in 2013 and 2012 were allocated entirely in accordance with the ownership interests.

SouthStar markets natural gas and related services under the trade name Georgia Natural Gas to retail customers primarily in Georgia, under various other trade names to retail customers in Ohio, Florida and New York, and to commercial and industrial customers in the southeastern United States.

There have been no significant changes to the primary risks associated with SouthStar beyond those discussed in our risk factors included in Item 1A of our 2012 Form 10-K.

SouthStar’s financial results are seasonal in nature, with business depending to a great extent on the first and fourth quarters of each year. SouthStar’s current assets consist primarily of natural gas inventory, derivative instruments and receivables from its customers. SouthStar also has receivables from us due to its participation in AGL Capital’s commercial paper program. See Note 2 for additional discussions of inventories. SouthStar’s restricted assets consist of customer deposits and were immaterial as of June 30, 2013 and 2012. SouthStar’s current liabilities consist primarily of accrued natural gas costs, other accrued expenses, customer deposits, derivative instruments and payables to us from its participation in AGL Capital’s commercial paper program.

SouthStar’s other contractual commitments and obligations, including operating leases and agreements with third party providers, do not contain terms that would trigger material financial obligations in the event that such contracts were terminated. As a result, our maximum exposure to a loss due to SouthStar’s contractual commitments and obligations is considered to be immaterial. SouthStar’s creditors have no recourse to our general credit beyond our corporate guarantees that we have provided to SouthStar’s counterparties and natural gas suppliers. We have provided no financial or other support that was not previously contractually required. With the exception of our corporate guarantees, we have not entered into any arrangements that could require us to provide financial support to SouthStar.

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

Cash flows used in our investing activities include capital expenditures for SouthStar of $1 million for the six months ended June 30, 2013 and 2012 and for the year ended December 31, 2012. Cash flows used in our financing activities include SouthStar’s distribution to Piedmont for its portion of SouthStar’s annual earnings from the previous year. Generally, this distribution occurs in the first quarter of each fiscal year. For the six months ended June 30, 2013, SouthStar distributed $17 million to Piedmont and $14 million during the same period last year. The increase was primarily the result of increased earnings year-over-year.

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

In millions	June 30, 2013 Consolidated	June 30, 2013 SouthStar		December 31, 2012 Consolidated	December 31, 2012 SouthStar		June 30, 2012 Consolidated	June 30, 2012 SouthStar	
Current assets	$ 2,063	$ 135	7 %	$ 2,668	$ 201	8 %	$ 1,880	$ 145	8 %
Long-term assets and other deferred debits	11,732	10	-	11,473	10	-	11,349	9	-
Total assets	$ 13,795	$ 145	1 %	$ 14,141	$ 211	1 %	$ 13,229	$ 154	1 %
Current liabilities	$ 2,349	$ 40	2 %	$ 3,338	$ 62	2 %	$ 2,460	$ 37	2 %
Long-term liabilities and other deferred credits	7,891	-	-	7,368	-	-	7,340	-	-
Total Liabilities	10,240	40	-	10,706	62	1	9,800	37	-
Equity	3,555	105	3	3,435	149	4	3,429	117	3
Total liabilities and equity	$ 13,795	$ 145	1 %	$ 14,141	$ 211	1 %	$ 13,229	$ 154	1 %

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

	Three months ended June 30,		Six months ended June 30,	
In millions	2013	2012	2013	2012
Operating revenues	$ 116	$ 99	$ 366	$ 314
Operating expenses				
Cost of goods sold	95	80	259	213
Operation and maintenance	15	12	33	31
Depreciation and amortization	-	1	1	1
Taxes other than income taxes	1	1	1	2
Total operating expenses	111	94	294	247
Operating income	$ 5	$ 5	$ 72	$ 67

Equity Method Investments

Income from our equity method investments is classified as other income in our unaudited Condensed Consolidated Statements of Income. The following table provides the income from our equity method investments. For more information about our equity method investments, see Note 10 to our Consolidated Financial Statements under Item 8 included in our 2012 Form 10-K.

	Three months ended June 30,		Six months ended June 30,	
In millions	2013	2012	2013	2012
Triton	$ 2	$ 3	$ 4	$ 6
Other	-	2	1	2

Note 9 - Commitments, Guarantees and Contingencies

Other than the changes in our debt, see Note 6 herein, there were no significant changes to our contractual obligations beyond those described in Note 11 to our Consolidated Financial Statements and related notes as filed in Item 8 of our 2012 Form 10-K.

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.

Contingencies and Guarantees

Contingent financial commitments, such as financial guarantees, represent obligations that become payable only if certain predefined events occur and include the nature of the guarantee and the maximum potential amount of future payments that could be required of us as the guarantor. We have certain subsidiaries that enter into various financial and performance guarantees and indemnities providing assurance to third parties. We believe the likelihood of payment under our guarantees and indemnities is remote. No liability has been recorded for such guarantees and indemnifications as the fair value is insignificant.

Regulatory Matters

On December 21, 2012, Atlanta Gas Light filed a petition with the Georgia Commission for approval to resolve an imbalance of approximately 4.8 Bcf of natural gas related to Atlanta Gas Light's use of retained storage assets to operationally balance the system for the benefit of the natural gas market. We believe that any costs associated with resolving the imbalance are recoverable from Marketers. The resolution of this imbalance will be decided by the Georgia Commission and we are unable to predict the ultimate outcome.

Environmental Matters

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at our current and former operating sites. The following table provides more information on the costs related to remediation of our current and former operating sites as of June 30, 2013.

In millions	Probabilistic model cost estimates	Engineering estimates	Amount recorded	Expected costs over next twelve months
Illinois	$ 208 - $458	$ 42	$ 250	$ 34
New Jersey	146 - 240	5	151	15
Georgia and Florida	42 - 100	11	56	8
North Carolina	n/a	11	11	5
Total	$ 396 - $798	$ 69	$ 468	$ 62

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

As we conduct the actual remediation and enter into cleanup contracts, we are increasingly able to provide conventional engineering estimates of the likely costs of many elements of the remediation program. These estimates contain various engineering assumptions, which we refine and update on an ongoing basis. With the exception of our North Carolina site, these costs are recoverable from our customers as they are paid and, accordingly, we have recorded a regulatory asset associated with the recorded liabilities. For more information on our environmental remediation costs, see Note 11 to our Consolidated Financial Statements and related notes as filed in Item 8 of our 2012 Form 10-K.

Litigation

We are involved in litigation arising in the normal course of business. Although in some cases the company is unable to estimate the amount of loss reasonably possible in addition to any amounts already recognized, it is possible that the resolution of these contingencies, either individually or in aggregate, will require the company to take charges against, or will result in reductions in, future earnings. Management believes that while the resolution of these contingencies, whether individually or in aggregate, could be material to earnings in a particular period, they will not have a material adverse effect on our consolidated financial position or cash flows. For additional litigation information, see Note 11 in our Consolidated Financial Statements and related notes in Item 8 of our 2012 Form 10-K.

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

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

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

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

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

In February 2012, we committed to a stipulated resolution of issues, which existed prior to our acquisition of Nicor Gas, with the staff of the Illinois Commission that would include crediting Nicor Gas customers $64 million. There were no new developments between the date of acquisition and the date of the stipulated resolution. The CUB and IAGO were not parties to the stipulated resolution and continue to pursue their claims in this proceeding. Evidentiary hearings before the Administrative Law Judges were held during the first quarter of 2012 and post-trial legal briefs from the parties were submitted during the second quarter of 2012. Following the submission of legal briefs, on November 5, 2012, the Administrative Law Judges issued a proposed order for a refund of $72 million to ratepayers. During the fourth quarter of 2012, we increased our accrual by $8 million for a total of $72 million as a result of these developments and its effect on the estimated liability.

On June 7, 2013, the Illinois Commission issued an order requiring us to refund $72 million to Nicor Gas' current customers over a 12-month period and we began issuing these refunds in July 2013. We maintain that the appropriate PBR refund is $64 million, consistent with the stipulated resolution with the Illinois Commission staff, and have filed an appeal for the amount in excess of that specified in the stipulated resolution. Any appeal must be filed by August 19, 2013.

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

Other We also are involved in an investigation by the United States Environmental Protection Agency regarding the applicable regulatory requirements for polychlorinated biphenyl in the Nicor Gas distribution system. While we are unable to predict the outcome of this matter or to reasonably estimate our potential exposure related thereto, if any, and have not recorded a liability associated with this contingency, the final disposition of this matter is not expected to have a material adverse impact on our liquidity or financial condition.

For additional litigation information on these matters, see Note 11 in our Consolidated Financial Statements and related notes in Item 8 of our 2012 Form 10-K.

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

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Note 10 - Segment Information

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

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

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

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

Our other segment includes intercompany eliminations and aggregated subsidiaries that are individually not significant enough to be reportable.

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

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

In millions	Three months ended June 30, 2013	2012	Six months ended June 30, 2013	2012
Operating income	$ 122	$ 91	$ 421	$ 353
Other income	7	9	12	13
EBIT	129	100	433	366
Interest expense	46	45	92	92
Earnings before income taxes	83	55	341	274
Income taxes	33	20	127	100
Net income	$ 50	$ 35	$ 214	$ 174

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Information by segment on our Statements of Financial Position as of December 31, 2012, is as follows:

In millions	Identifiable and total assets (1)	Goodwill
Distribution operations	$ 11,320	$ 1,640
Retail operations	511	122
Wholesale services	1,218	-
Midstream operations	720	14
Cargo shipping	464	61
Other (2)	(92)	-
Consolidated	$ 14,141	$ 1,837

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

(2) The assets of our other segment consist primarily of cash and cash equivalents and PP&E, and reflect the effect of intercompany eliminations.

Summarized Statements of Income, Statements of Financial Position and capital expenditure information by segment as of and for the periods presented are shown in the following tables.

Three months ended June 30, 2013

In millions	Distribution operations	Retail operations	Wholesale services	Midstream operations	Cargo shipping	Other and intercompany eliminations (4)	Consolidated
Operating revenues from external parties	$ 615	$ 165	$ 21	$ 15	$ 88	$ -	$ 904
Intercompany revenues (1)	43	-	-	-	-	(43)	-
Total operating revenues	658	165	21	15	88	(43)	904
Operating expenses							
Cost of goods sold	266	115	10	4	54	(42)	407
Operation and maintenance	159	32	10	6	30	(4)	233
Depreciation and amortization	90	5	1	4	5	4	109
Taxes other than income taxes	38	1	-	2	2	1	44
Total operating expenses	553	153	21	16	91	(41)	793
Gain on sale of Compass Energy	-	-	11	-	-	-	11
Operating income (loss)	105	12	11	(1)	(3)	(2)	122
Other income	4	-	-	1	2	-	7
EBIT	$ 109	$ 12	$ 11	$ -	$ (1)	$ (2)	$ 129
Capital expenditures	$ 158	$ 3	$ -	$ 4	$ 2	$ 3	$ 170

Three months ended June 30, 2012

In millions	Distribution operations	Retail operations	Wholesale services	Midstream operations	Cargo shipping	Other and intercompany eliminations (4)	Consolidated
Operating revenues from external parties	$ 449	$ 136	$ 7	$ 18	$ 80	$ (4)	$ 686
Intercompany revenues (1)	41	-	-	-	-	(41)	-
Total operating revenues	490	136	7	18	80	(45)	686
Operating expenses							
Cost of goods sold	131	93	4	7	51	(46)	240
Operation and maintenance	152	25	11	4	26	-	218
Depreciation and amortization	86	3	-	4	6	3	102
Taxes other than income taxes	25	1	1	2	1	2	32
Nicor merger expenses (2)	-	-	-	-	-	3	3
Total operating expenses	394	122	16	17	84	(38)	595
Operating income (loss)	96	14	(9)	1	(4)	(7)	91
Other income	4	-	-	1	3	1	9
EBIT	$ 100	$ 14	$ (9)	$ 2	$ (1)	$ (6)	$ 100
Capital expenditures	$ 146	$ 2	$ -	$ 17	$ 1	$ 13	$ 179

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Six months ended June 30, 2013

In millions	Distribution operations	Retail operations	Wholesale services	Midstream operations	Cargo shipping	Other and intercompany eliminations (4)	Consolidated
Operating revenues from external parties	$ 1,879	$ 467	$ 60	$ 39	$ 175	$ (7)	$ 2,613
Intercompany revenues (1)	98	-	-	-	-	(98)	-
Total operating revenues	1,977	467	60	39	175	(105)	2,613
Operating expenses							
Cost of goods sold	1,031	310	20	16	107	(104)	1,380
Operation and maintenance	344	63	23	12	58	(8)	492
Depreciation and amortization	180	10	1	8	10	7	216
Taxes other than income taxes	102	2	1	3	3	4	115
Total operating expenses	1,657	385	45	39	178	(101)	2,203
Gain on sale of Compass Energy	-	-	11	-	-	-	11
Operating income (loss)	320	82	26	-	(3)	(4)	421
Other income	7	-	-	2	4	(1)	12
EBIT	$ 327	$ 82	$ 26	$ 2	$ 1	$ (5)	$ 433
Identifiable and total assets (3)	$ 11,166	$ 641	$ 1,008	$ 715	$ 462	$ (197)	$ 13,795
Goodwill	$ 1,640	$ 168	$ -	$ 14	$ 61	$ -	$ 1,883
Capital expenditures	$ 295	$ 4	$ -	$ 8	$ 3	$ 8	$ 318

Six months ended June 30, 2012

In millions	Distribution operations	Retail operations	Wholesale services	Midstream operations	Cargo shipping	Other and intercompany eliminations (4)	Consolidated
Operating revenues from external parties	$ 1,443	$ 399	$ 71	$ 34	$ 164	$ (21)	$ 2,090
Intercompany revenues (1)	87	-	-	-	-	(87)	-
Total operating revenues	1,530	399	71	34	164	(108)	2,090
Operating expenses							
Cost of goods sold	660	259	34	12	101	(107)	959

Operation and maintenance	325	57	24	9	54	(6)	463
Depreciation and amortization	174	7	1	6	12	6	206
Taxes other than income taxes	82	2	2	3	3	4	96
Nicor merger expenses (2)	-	-	-	-	-	13	13
Total operating expenses	1,241	325	61	30	170	(90)	1,737
Operating income (loss)	289	74	10	4	(6)	(18)	353
Other income	5	-	-	1	6	1	13
EBIT	$ 294	$ 74	$ 10	$ 5	$ -	$ (17)	$ 366
Identifiable and total assets (3)	$ 10,784	$ 452	$ 895	$ 685	$ 471	$ (58)	$ 13,229
Goodwill	$ 1,586	$ 124	$ 2	$ 16	$ 77	$ 8	$ 1,813
Capital expenditures	$ 268	$ 4	$ -	$ 59	$ 1	$ 18	$ 350

(1) Intercompany revenues - wholesale services records its energy marketing and risk management revenues on a net basis and its total operating revenues include intercompany revenues of $103 million and $243 million for the three and six months ended June 30, 2013 and $49 million and $137 million for the three and six months ended June 30, 2012.

(2) Transaction expenses associated with the Nicor merger are shown separately to better compare year-over-year results.

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

(4) The assets of our other segment consist primarily of cash and cash equivalents and PP&E, and reflect the effect of intercompany eliminations.

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

The following discussion and analysis should be read in conjunction with our unaudited Condensed Consolidated Financial Statements and the notes to our unaudited Condensed Consolidated Financial Statements in this quarterly filing, as well as our 2012 Form 10-K. Results for the interim periods presented are not necessarily indicative of the results to be expected for the full fiscal period due to seasonal and other factors.

Forward-Looking Statements

Certain expectations and projections regarding our future performance referenced in this section and elsewhere in this report, as well as in other reports and proxy statements we file with the SEC or otherwise release to the public and on our website are forward-looking statements and are subject to uncertainties and risks. 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 often include words such as "anticipate," "assume," “believe,” "can," "could," "estimate," "expect," "forecast," "future," “goal,” "indicate," "intend," "may," “outlook,” "plan," “potential,” "predict," "project," “proposed,” "seek," "should," "target," "would," or similar expressions. You are cautioned not to place undue reliance on our forward-looking statements. While we believe that our expectations are reasonable in view of the available information that we currently have, our expectations are subject to future events, risks and uncertainties, and there are numerous factors - many beyond our control - that could cause our actual results to vary from our expectations.

Such events, risks and uncertainties include, but are not limited to, changes in price, supply and demand for natural gas and related products; the impact of changes in state and federal legislation and regulation including any changes related to climate change; actions taken by government agencies on rates and other matters; concentration of credit risk; utility and energy industry consolidation; the impact on cost and timeliness of construction projects by government and other approvals, development project delays, adequacy of supply of diversified vendors, unexpected change in project costs, including the cost of funds to finance these projects; limits on pipeline capacity; the impact of acquisitions and divestitures; our ability to successfully integrate operations that we have or may acquire or develop in the future; direct or indirect effects on our business, financial condition or liquidity resulting from any change in our credit ratings, or any change in the credit ratings of our counterparties or competitors; interest rate fluctuations; financial market conditions, including disruptions in the capital markets and lending environment; general economic conditions; uncertainties about environmental issues and the related impact of such issues, including our environmental remediation plans; the impact of our depreciation study for Nicor Gas and related legislation; the impact of changes in weather, including climate change, on the temperature-sensitive portions of our business; the impact of natural disasters, such as hurricanes, on the supply and price of natural gas and on our cargo shipping business; acts of war or terrorism; the outcome of litigation; and other factors discussed elsewhere herein and in our other filings with the SEC. There also may be other factors that we do not anticipate or that we do not recognize as material that are not described in this report that could cause our actual results to differ materially from our expectations.

Forward-looking statements speak only as of the date they are made. We expressly disclaim any obligation to publicly update or revise any forward-looking statement, whether as a result of future events, new information or otherwise, except as required under United States federal securities law.

Executive Summary

We are an energy services holding company whose principal business is the distribution of natural gas in seven states - Illinois, Georgia, Virginia, New Jersey, Florida, Tennessee and Maryland - through our seven natural gas distribution

utilities. We are also involved in several other businesses that are primarily related and complementary to the distribution of natural gas. Our operating segments consist of the following five operating and reporting segments – distribution operations, retail operations, wholesale services, midstream operations and cargo shipping and one non-operating segment - other. These segments are consistent with how management views and operates our business. For additional information on our operating segments, see Note 10 to our unaudited Condensed Consolidated Financial Statements herein and Item 1, “Business” of our 2012 Form 10-K. Following are summarized recent developments for our operating segments.

Overview In the first half of 2013, we benefited from the return to more normal weather as compared to the historically warm weather in 2012. Excluding weather, we achieved growth in our operating margins during the first half of 2013 primarily as a result of our regulatory infrastructure programs in our distribution operations, targeted acquisition growth in retail operations, and higher contributions from commercial activity in our wholesale operations.

We continue to effectively manage costs and leverage our shared services model across our businesses to largely overcome inflationary effects. As expected, our operation and maintenance expenses in the first half of 2013 increased as a result of returning to targeted levels of incentive compensation. In addition, bad debt expense has increased modestly for some of our businesses as a result of colder weather and higher natural gas prices compared to 2012, which resulted in higher average customer bills. Our operation and maintenance expenses, excluding rider pass through expenses and incremental expenses related to the service plans acquired in January 2013, have otherwise decreased slightly and we continue to maintain significant focus on costs.

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Distribution Operations At June 30, 2013, our seven utilities within distribution operations served approximately 4.5 million end-use customers with their primary focus being the safe and reliable delivery of natural gas.

Nicor Gas On June 7, 2013, the Illinois Commission issued an order requiring us to refund $72 million to Nicor Gas' current customers over a 12-month period in connection with Nicor Gas' operation of a PBR plan from 2000 to 2002. We continue to maintain that the appropriate PBR refund is $64 million, consistent with our stipulated resolution agreed to by Nicor Gas and the staff of the Illinois Commission, and have appealed the amount in excess of that specified in the stipulated resolution. On July 1, 2013, Nicor Gas began refunding the $72 million, with approximately 40% to be refunded in 2013 and 60% to be refunded in 2014. Nicor Gas previously accrued $72 million for this contingent liability, which is in line with the order issued by the Illinois Commission. Any appeal must be filed by August 19, 2013. See Note 9 to our unaudited Condensed Consolidated Financial Statements for additional information.

In June 2013, we entered into an OTC weather derivative to reduce the risk of lower operating margins as a result of significantly warmer-than-normal weather in Illinois during the fourth quarter of 2013. The weather derivative is based on fourth quarter 2013 Heating Degree Days at Chicago Midway International Airport. This is a cash-settled option and we will retain substantially all upside potential should the fourth quarter be colder-than-normal, but our operating margin will be largely protected in the event of significantly warmer-than-normal weather.

In July 2013, Illinois enacted legislation that will allow Nicor Gas to provide more widespread safety and reliability enhancements to its system in a timelier manner than under traditional utility regulation, and pass along lower program costs to our customers. We expect to submit a plan for approval by the Illinois Commission in mid-2014 and begin work in 2015.

In May 2013, the Illinois legislature passed legislation that, if signed by the Governor of Illinois, would provide a streamlined process for natural gas utilities serving more than 1.6 million customers as of January 1, 2013 to revise their depreciation rates. Accordingly, this legislation is applicable to Nicor Gas which has 2.2 million customers. If approved, the Illinois Commission has 120 days after our depreciation study is filed to review and rule on the proposed depreciation rate. Any change in the depreciation rate would become effective as of the date the depreciation study was filed and a retroactive adjustment to depreciation expense would be recognized.

We are in the final stages of completing a depreciation study for Nicor Gas and expect the final study will result in a decrease to our current composite, straight-line rate for Nicor Gas of 4.1%. A 10 basis point decrease in this rate is estimated to lower our annual depreciation expense by $4 million to $6 million. We expect to file our depreciation study with the Illinois Commission during the third quarter of 2013 and do not anticipate that our current customer rates will be affected by a decrease to our depreciation rate.

Atlanta Gas Light In December 2012, Atlanta Gas Light filed a petition with the Georgia Commission for approval to resolve an imbalance of approximately 4.8 Bcf of natural gas related to Atlanta Gas Light's use of retained storage assets to operationally balance the system for the benefit of the natural gas market. We believe that any costs associated with resolving the imbalance are recoverable from Marketers. The resolution of this imbalance will be decided by the Georgia Commission and we are unable to predict the ultimate outcome.

Virginia Natural Gas In May 2013, the Virginia Commission approved Virginia Natural Gas' Conservation and Ratemaking Efficiency (CARE) plan. The plan provides for a modified CARE plan that includes a more limited set of conservation programs and measures at a reduced cost of $2 million over a three-year period.

Chattanooga Gas In April 2013, legislation was signed into law that gives the Tennessee Authority the ability to approve alternative regulatory mechanisms. The law allows the Tennessee Authority to: (i) implement separate rate adjustment mechanisms that track specific costs, (ii) implement annual rate reviews in lieu of traditional rate cases and

(iii) adopt other policies or procedures that permit a more timely review and revision of rates, streamline the regulatory process, and reduce the cost and time associated with the traditional ratemaking processes.

In April 2013, Chattanooga Gas filed a proposal with the Tennessee Authority to extend its energy conservation programs and associated rate adjustment mechanism that adjusts rates to recover reduced operating revenues as a result of reduced customer usage. In August 2013, a status conference will be held by the Tennessee Authority, at which time a procedural schedule will be established.

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Retail Operations Our retail operations businesses serve approximately 0.6 million energy customers and approximately 1.2 million service contracts in Florida, Georgia, Illinois, Indiana, Kentucky, Ohio, Maryland, Massachusetts, New York, Pennsylvania and West Virginia. SouthStar, Nicor Advanced Energy and Nicor Solutions generate earnings through the sale of natural gas to residential, commercial and industrial customers, primarily in Georgia and
Illinois where we capture spreads between wholesale and retail natural gas prices. Additionally, these businesses offer our customers energy-related products that provide for natural gas price stability and utility bill management. These products mitigate and/or eliminate the risks to customers of colder-than-normal weather and/or changes in natural gas prices. We charge a fee or premium for these services. Our retail operations businesses also provide warranty protection and home solutions that include gas and electric line repair, equipment repair, insurance and maintenance through Pivotal Home Solutions and represent customers who are on monthly service contracts or warranty products billed at a fixed monthly amount.

As described in Note 2 to our unaudited Condensed Consolidated Financial Statements, during June 2013, our retail operations segment acquired approximately 33,000 residential and commercial relationships in Illinois for $32 million. The transaction significantly increases the size of our retail energy customer portfolio in Illinois with minimal incremental operating expenses. We expect this transaction to result in approximately $4 million of EBIT during 2013.

In January 2013, our retail operations segment acquired approximately 500,000 service plans and certain other assets for $120 million, plus $2 million of working capital. We believe this acquisition will provide an enhanced platform for growth and continued expansion of this business into a number of key markets.

Wholesale Services Our wholesale services segment consists of our wholly owned subsidiary Sequent and engages in asset management and optimization, storage, transportation, producer and peaking services and wholesale marketing of natural gas across the United States and in Canada. It also provides natural gas asset management and/or related logistics services for most of our utilities, as well as for non-affiliated companies. In April 2013, the Tennessee Authority authorized an extension of the asset management agreement between Chattanooga Gas and Sequent. The terms of the agreement remain unchanged, except the expiration date is now March 2015.

In May 2013, we sold Compass Energy, a non-regulated retail natural gas business supplying commercial and industrial customers. Upon completion of the sale, we received an initial cash payment of $12 million, which resulted in an $11 million pre-tax gain. Additionally, we are eligible to receive contingent cash consideration up to $8 million with a guaranteed minimum receipt of $3 million. The amount of the contingent cash consideration will be paid over a five-year earn out period based upon the financial performance of Compass Energy. See Note 2 to our unaudited Condensed Consolidated Financial Statements for additional information.

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

Golden Triangle Storage’s Cavern 1 began commercial operations in September 2010, and Cavern 2 began commercial operations in September 2012. Cavern 1 is currently going through a process to monitor its working gas and restore capacity that was lost to normal capacity shrinkage in the cavern. The process began in early 2013 and is expected to continue with limited commercial operations resuming in the third quarter of 2013. We expect Cavern 1 to return to full commercial service in the first quarter of 2014. Cavern 2 will continue to cover the obligations of Cavern 1 during this process. Central Valley, located in northern California, began commercial operations for firm customers during

the second quarter of 2012.

Through our wholly owned subsidiary Cypress Creek Gas Storage, LLC and as a result of our merger with Nicor, we own a 50% interest in Sawgrass Storage, LLC (Sawgrass Storage), a joint venture between us and a privately held energy exploration and production company. Sawgrass Storage was granted certification from the Federal Energy Regulatory Commission (FERC) in March 2012 for the development of an underground natural gas storage facility in Louisiana with 30 Bcf of working gas capacity (expandable to 40 Bcf). The FERC certificate is set to expire in March 2014 if not extended. Given the current weakness in the natural gas storage market and the FERC certificate set to expire, we along with our joint venture partner continue to evaluate our on-going strategy for the Sawgrass Storage facility. Currently, our investment in Sawgrass Storage is $9 million, which could potentially be written-off or impaired in the event of a continued decline in natural gas market fundamentals and the rates for contracting availability capacity, the FERC certificate not being extended or other strategic decisions made by us, our joint venture partner or the joint venture.

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

Natural gas market fundamentals Volatility in the natural gas market arises from a number of factors, such as weather fluctuations or changes in supply or demand for natural gas in different regions of the country. The volatility of natural gas commodity prices has a significant impact on our customer rates, our long-term competitive position against other energy sources and the ability of our retail operations and wholesale services segments to capture value from location and seasonal spreads. Additionally, changes in commodity prices subject a significant portion of our operations to earnings variability. Since 2011, the volatility of the daily Henry Hub spot market prices for natural gas – a benchmark measure for natural gas generally - in the United States has been significantly lower than it had been in previous years. This is the result of a robust natural gas supply, the weak economy and ample natural gas storage.

Our utility natural gas acquisition strategy is designed to secure sufficient supplies of natural gas and the rights to physically flow natural gas between delivery points in order to meet the needs of our utility customers and to hedge gas prices and location spreads to manage costs, reduce price volatility for our utility customers and maintain a competitive advantage.

Our non-utility businesses principally use physical and financial arrangements to reduce the risks associated with both weather-related seasonal fluctuations in market conditions and changing commodity prices. Additionally, our hedging strategies and physical natural gas supplies in storage enable us to reduce earnings risk exposure due to higher gas costs. These economic hedges may not qualify, or may not be designated, for hedge accounting treatment. As a result, our reported earnings for the wholesale services, retail operations and midstream operations segments reflect changes in the fair values of certain derivatives. Accordingly, a decline in natural gas prices or decreases in transportation spreads generally results in hedge gains and correspondingly increases in EBIT, while an increase in natural gas prices or a widening of transportation spreads generally results in hedge losses and correspondingly decreases in EBIT. These values may change significantly from period to period and are reflected as gains or losses within our operating revenues or our OCI for those derivative instruments that qualify and are designated as accounting hedges.

It is possible that natural gas prices will remain low for an extended period based on current levels of excess supply relative to market demand for natural gas, in part due to abundant sources of new shale natural gas reserves and the lack of demand by commercial and industrial enterprises. However, as economic conditions continue to improve, the demand for natural gas may increase, natural gas prices could rise and higher volatility could return to the natural gas markets. Consequently, we are working to reposition our wholesale services business model with respect to fixed costs, and the types of contracts pursued and executed.

The market fundamentals of midstream operations storage business are cyclical, and as discussed above, the abundant supply of natural gas in recent years and the resulting lack of market and price volatility have negatively impacted the profitability of our storage facilities. In 2013, expiring storage capacity contracts were re-subscribed at lower prices and we anticipate these lower natural gas prices to continue throughout 2013 as compared to historical averages. Due to the current market storage rates, we did not re-contract 2.0 Bcf at Golden Triangle Storage and intend to provide other services until market conditions improve to support term contracts. As of June 30, 2013, the overall average firm subscription rate per facility is as follows:

	Average Monthly Rate per Dekatherm

Jefferson Island (1)	$	0.111
Golden Triangle (1)		0.182
Central Valley		0.130

(1) Includes firm capacity contracted by Sequent at April 1, 2013 of 1.5 Bcf at an average monthly rate of $0.07 per dekatherm at Jefferson Island and 2 Bcf at an average monthly rate of $0.125 per dekatherm at Golden Triangle.

While the average monthly rates were lower than prior years and we did not re-contract all of the available capacity during the first half of 2013, our current projections remain consistent with those from our most recent annual impairment assessment given the revenues that are expected to be earned from other storage services. We will continue to monitor all of our reporting units for impairment indicators throughout the year, but as of June 30, 2013, we believe there are no indications of potential impairment.

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Results of Operations

We generate the majority of our operating revenues through the sale, distribution and storage of natural gas. We include in our consolidated revenues an estimate of revenues from natural gas distributed, but not yet billed to residential, commercial and industrial customers from the date of the last bill to the end of the reporting period. No individual customer or industry accounts for a significant portion of our revenues.

The operating revenues and EBIT of our distribution operations and retail operations segments are seasonal. During the Heating Season, natural gas usage and operating revenues are generally higher as more customers are connected to our distribution systems and natural gas usage is higher in periods of colder weather. Our base operating expenses, excluding cost of gas, revenue taxes, interest expense and certain incentive compensation costs, are generally incurred relatively equally over any given year. Additionally, the revenues of our cargo shipping business are generally higher in the fourth quarter, due to increased tourist-related shipments as the hotels, resorts, and cruise ships typically have increased occupancy rates commencing in the fourth quarter and increasing further into the first quarter and consumer spending increases during traditional holiday periods. Revenues are also impacted during the fourth quarter by Peak Season Surcharges. Thus, our operating results vary significantly from quarter to quarter as a result of seasonality.

We evaluate segment performance using the measures of operating margin and EBIT, which include the effects of corporate expense allocations. Operating margin is a non-GAAP measure that is calculated as operating revenues minus cost of goods sold and revenue tax expense in distribution operations. Operating margin excludes operation and maintenance expense, depreciation and amortization, certain taxes other than income taxes, and the gain or loss on the sale of our assets, if any. These items are included in our calculation of operating income as reflected in our unaudited Condensed Consolidated Statements of Income. EBIT is also a non-GAAP measure that includes operating income and other income and expenses. Items that we do not include in EBIT are financing costs, including interest and debt expense and income taxes, each of which we evaluate on a consolidated basis.

We believe operating margin is a better indicator than operating revenues of the contribution resulting from customer growth in our distribution operations segment, since the cost of goods sold and revenue tax expenses can vary significantly and are generally billed directly to our customers. We also consider operating margin to be a better indicator in our retail operations, wholesale services, midstream operations and cargo shipping segments, since it is a direct measure of operating margin generated before overhead costs.

We believe EBIT is a useful measurement of our operating segments' performance because it provides information that can be used to evaluate the effectiveness of our businesses from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which is directly relevant to the efficiency of those operations. You should not consider operating margin or EBIT an alternative to, or a more meaningful indicator of, our operating performance than operating income or net income attributable to AGL Resources Inc. as determined in accordance with GAAP. In addition, our operating margin and EBIT measures may not be comparable to similarly titled measures of other companies.

We believe presenting the non-GAAP measurements of basic and diluted earnings per share - as adjusted, which excludes Nicor merger-related expenses, provides investors with an additional measure of our performance. Adjusted basic and diluted earnings per share should not be considered an alternative to, or a more meaningful indicator of, our operating performance than our GAAP basic and diluted earnings per share. The following table reconciles operating revenue and operating margin to operating income, and EBIT to earnings before income taxes and net income, and our GAAP basic and diluted earnings per common share to our non-GAAP basic and diluted earnings per share – as adjusted, together with other consolidated financial information for the periods presented.

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	Three months ended June 30,			Six months ended June 30,		
In millions, except per share amounts	2013	2012	Change	2013	2012	Change
Operating revenues	$ 904	$ 686	$ 218	$ 2,613	$ 2,090	$ 523
Cost of goods sold	(407)	(240)	(167)	(1,380)	(959)	(421)
Revenue tax expense (1)	(24)	(13)	(11)	(73)	(54)	(19)
Operating margin	473	433	40	1,160	1,077	83
Operating expenses (2)	(386)	(352)	(34)	(823)	(765)	(58)
Revenue tax expense (1)	24	13	11	73	54	19
Sale of Compass Energy	11	-	11	11	-	11
Nicor merger expenses (2)	-	(3)	3	-	(13)	13
Operating income	122	91	31	421	353	68
Other income	7	9	(2)	12	13	(1)
EBIT	129	100	29	433	366	67
Interest expenses	(46)	(45)	(1)	(92)	(92)	-
Earnings before income taxes	83	55	28	341	274	67
Income tax expenses	(33)	(20)	(13)	(127)	(100)	(27)
Net income	50	35	15	214	174	40
Less net income attributable to the noncontrolling interest	1	1	-	11	10	1
Net income attributable to AGL Resources Inc.	$ 49	$ 34	$ 15	$ 203	$ 164	$ 39
Per common share data						
Basic earnings per common share attributable to AGL Resources Inc. common shareholders (3)	$ 0.41	$ 0.28	$ 0.13	$ 1.72	$ 1.40	$ 0.32
Transaction costs of Nicor merger	-	0.02	(0.02)	-	0.07	(0.07)
Basic earnings per share - as adjusted	$ 0.41	$ 0.30	$ 0.11	$ 1.72	$ 1.47	$ 0.25
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders (3)	$ 0.41	$ 0.28	$ 0.13	$ 1.72	$ 1.40	$ 0.32
Transaction costs of Nicor merger	-	0.02	(0.02)	-	0.07	(0.07)
Diluted earnings per share - as adjusted	$ 0.41	$ 0.30	$ 0.11	$ 1.72	$ 1.47	$ 0.25

(1) Adjusted for Nicor Gas' revenue tax expenses, which are passed directly through to customers.
(2) Expenses associated with the Nicor merger are part of operating expenses, but are shown separately to better compare year-over-year results.
(3) Sale of Compass Energy generated basic and diluted EPS of $0.04 for the three and six months ending June 30, 2013.

For the second quarter of 2013, our net income attributable to AGL Resources Inc. increased by $15 million or 44% compared to last year.

- The increase was primarily the result of increased operating margin at distribution operations and retail operations due to colder weather and increased average customer usage compared to the same period in the prior year, and increased regulatory infrastructure program revenues at Atlanta Gas Light. The operating margin of our wholesale services segment for the quarter increased by $8 million as a result of higher commercial activity. The increase in our net income attributable to AGL Resources Inc. was also favorably impacted by the $11 million pre-tax gain on the sale of Compass Energy in our wholesale services segment.
- The increases were partially offset by increased operating expenses at distribution operations as our incentive compensation expense increased to targeted levels. In addition, our bad debt expense increased at retail operations as a result of colder weather combined with natural gas prices that were higher than in the same period of the prior year.
- During the three months ended June 30, 2012, we recorded $3 million ($2 million net of tax) of Nicor merger related expenses.

For the six months ended June 30, 2013, our net income attributable to AGL Resources Inc. increased by $39 million or 24% compared to last year.

- The primary drivers of this increase are consistent with those described above for the second quarter of 2013 compared to 2012.
- During the six months ended June 30, 2012, we recorded $13 million ($8 million net of tax) of Nicor merger related expenses.

For the second quarter of 2013, our income tax expense increased by $13 million compared to the second quarter of 2012 and by $27 million for the six months ended June 30, 2013 compared to the same period of 2012. The increases were primarily due to higher consolidated earnings, as previously discussed. Our income tax expense is determined from earnings before income taxes less net income attributable to noncontrolling interest.

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Operating Metrics

Weather We measure the effects of weather on our business through Heating Degree Days. Generally, increased Heating Degree Days result in higher demand for gas on our distribution systems. With the exception of Nicor Gas and Florida City Gas, we have various regulatory mechanisms, such as weather normalization mechanisms, which limit our exposure to weather changes within typical ranges in each of our utilities' respective service areas. However, our customers in Illinois and retail operations' customers in Georgia can be impacted by warmer or colder than normal weather. We have presented the Heating Degree Day information for those locations in the following table.

	Three months ended June 30,			2013 vs. 2012	2013 vs. normal	Six months ended June 30,			2013 vs. 2012	2013 vs. normal
Weather (Heating Degree Days)	Normal	2013	2012	colder	colder	Normal	2013	2012	colder	colder
Illinois (1) (2)	623	715	542	32 %	15 %	3,614	3,868	2,900	33 %	7 %
Georgia (1)	136	178	72	147 %	31 %	1,588	1,639	1,055	55 %	3 %

(1) Normal represents the ten-year average from January 1, 2003 through June 30, 2012, for Illinois at Chicago Midway International Airport, and for Georgia at Atlanta Hartsfield-Jackson International Airport as obtained from the National Oceanic and Atmospheric Administration, National Climatic Data Center.

(2) The 10-year average Heating Degree Days for the period, as established by the Illinois Commission in our last rate case, is 617 for the second quarter and 3,519 for the first six months from 1998 through 2007.

During the three months ended June 30, 2013, weather in Illinois was 15% colder-than-normal and 32% colder than last year. Georgia also experienced 31% colder-than-normal weather, and 147% colder than the same period in the prior year. During the six months ended June 30, 2013, we experienced weather in Illinois that was 7% colder-than-normal and 33% colder than the same period in the prior year. Georgia also experienced 3% colder-than-normal weather, and 55% colder than the same period last year.

Customers Our customer metrics highlight the average number of customers for which we provide services and are provided in the following table. The number of customers at distribution operations and energy customers at retail operations can be impacted by natural gas prices, economic conditions and competition from alternative fuels. Our year-over-year consolidated utility customer growth rate was 0.5% and 0.4% for the three and six months ended June 30, 2013, respectively, and we anticipate overall utility customer growth trends for 2013 to improve compared to prior year.

Our energy customers at retail operations are primarily located in Georgia and Illinois. The market in Georgia remains very competitive, which we expect will continue for the foreseeable future. In 2013, our retail operations segment intends on continuing its efforts to enter and expand within targeted markets to increase its energy customers and expand our service contracts to include our service territories in Virginia and Tennessee.

	Three months ended June 30,		2013 vs. 2012	Six months ended June 30,		2013 vs. 2012
Customers and service contracts (average end-use, in thousands)	2013	2012	% change	2013	2012	% change
Distribution operations customers	4,492	4,468	1 %	4,496	4,478	- %
Retail operations						
Energy customers (1)	618	615	- %	616	645	(4)%

Service contracts (2)	1,176		689		71	%	1,095		701		56	%
Market share in Georgia	32	%	32	%	-	%	32	%	32	%	-	%

(1) A portion of the customers represents customer equivalents in Ohio, which are computed by the actual delivered volumes divided by the expected average customer usage. Decrease primarily due to our contract to serve approximately 50,000 customer equivalents that ended on April 1, 2012.

(2) Increase primarily due to acquisition of approximately 500,000 service contracts on January 31, 2013.

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

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Volumes	Three months ended June 30, 2013	2012	2013 vs. 2012 % change	Six months ended June 30, 2013	2012	2013 vs. 2012 % change
Distribution operations (In Bcf)						
Firm	107	93	15 %	416	333	25 %
Interruptible	26	26	- %	56	53	6 %
Total	133	119	12 %	472	386	22 %
Retail operations (In Bcf)						
Georgia firm	5	3	67 %	23	17	35 %
Illinois	1	1	- %	5	5	- %
Other (1)	1	1	- %	4	5	(20)%
Wholesale services						
Daily physical sales (Bcf / day)	5.3	4.9	8 %	5.8	5.4	7 %
Cargo shipping (TEU's - in thousands)						
Shipments	45	40	13 %	90	81	11 %

	As of June 30, 2013	2012
Midstream operations		
Working natural gas capacity (in Bcf) (2)	31.8	24.3
% of firm capacity under subscription by third parties (3)	33 %	58 %

(1) Includes Florida, Maryland, New York and Ohio.

(2) Includes Central Valley Storage that was acquired in connection with the Nicor merger, and began commercial operations in the second quarter of 2012. Additionally, Golden Triangle Storage's Cavern 1 is currently going through a process to monitor its working gas capacity and slightly increase the size of the facility. The process began in early 2013 and is expected to continue with limited commercial operations resuming in the third quarter of 2013. We expect Cavern 1 to return to full commercial service in the first quarter of 2014. Cavern 2 will cover the obligations of Cavern 1 during this process.

(3) The percentage of capacity under subscription does not include 3.5 Bcf of capacity under contract with Sequent at June 30, 2013, and 3 Bcf of capacity under contract with Sequent at June 30, 2012.

Three and six months ended June 30, 2013 compared to three and six months ended June 30, 2012

Operating margin, operating expenses and EBIT information for each of our segments are contained in the following tables:

	Three months ended June 30, 2013			Three months ended June 30, 2012		
In millions	Operating margin (1) (2)	Operating expenses (2)	EBIT (1) (4)	Operating margin (1) (2)	Operating expenses (2) (3)	EBIT (1)
	$ 368	$ 263	$ 109	$ 346	$ 250	$ 100

Distribution operations						
Retail operations	50	38	12	43	29	14
Wholesale services (4)	11	11	11	3	12	(9)
Midstream operations	11	12	-	11	10	2
Cargo shipping	34	37	(1)	29	33	(1)
Other	(1)	1	(2)	1	8	(6)
Consolidated	$ 473	$ 362	$ 129	$ 433	$ 342	$ 100

	Six months ended June 30, 2013			Six months ended June 30, 2012		
In millions	Operating margin (1) (2)	Operating expenses (2)	EBIT (1) (4)	Operating margin (1) (2)	Operating expenses (2) (3)	EBIT (1)
Distribution operations	$ 873	$ 553	$ 327	$ 816	$ 527	$ 294
Retail operations	157	75	82	140	66	74
Wholesale services (4)	40	25	26	37	27	10
Midstream operations	23	23	2	22	18	5
Cargo shipping	68	71	1	63	69	-
Other	(1)	3	(5)	(1)	17	(17)
Consolidated	$ 1,160	$ 750	$ 433	$ 1,077	$ 724	$ 366

(1) These are non-GAAP measures. A reconciliation of operating margin to operating income and EBIT to earnings before income taxes and net income is contained in “Results of Operations” herein. See Note 10 to our unaudited Condensed Consolidated Financial Statements under Item 1 herein for additional segment information.

(2) Operating margin and expense are adjusted for revenue tax expense for Nicor Gas, which is passed directly through to customers.

(3) Includes $3 million and $13 million in Nicor merger transaction expenses for the three and six months ended June 30, 2012.

(4) EBIT includes $11 million gain on sale of Compass Energy.

Distribution Operations

Our distribution operations segment is the largest component of our business and is subject to regulation and oversight by agencies in each of the seven states we serve. These agencies approve natural gas rates designed to provide us the opportunity to generate revenues to recover the cost of natural gas delivered to our customers and our fixed and variable costs, such as depreciation, interest, maintenance and overhead costs, and to earn a reasonable return for our shareholders.

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With the exception of Atlanta Gas Light, our second-largest utility, the earnings of our regulated utilities can be affected by customer consumption patterns that are a function of weather conditions, price levels for natural gas and general economic conditions that may impact our customers' ability to pay for gas consumed. For the three and six months ended June 30, 2013, distribution operations' EBIT increased by $9 million or 9% and $33 million or 11%, respectively, compared to prior year, as shown in the following table.

In millions	Three months ended	Six months ended
EBIT - for June 30, 2012	$ 100	$ 294
`		
Operating margin		
Increased operating margin mainly driven by colder weather and higher customer usage at Nicor Gas, Florida City Gas, Elizabethtown Gas and Virginia Natural Gas compared to prior year	10	27
Increased rider revenues primarily as a result of energy efficiency program recoveries at Nicor Gas	2	12
Increased revenues from regulatory infrastructure programs, primarily at Atlanta Gas Light	10	18
Increase in operating margin	22	57
Operating expenses		
Increased rider expenses primarily as a result of energy efficiency program expenses at Nicor Gas	2	12
Increased incentive compensation costs due to amounts returning to targeted levels	4	9
Increased depreciation expense as a result of increased PP&E from infrastructure additions and improvements	4	6
Decreased benefits expenses primarily related to medical claims and retiree healthcare costs	(3)	(6)
Increased outside service costs and other	6	5
Increase in operating expenses	13	26
Increased AFUDC equity primarily from STRIDE projects at Atlanta Gas Light	-	2
EBIT - for June 30, 2013	$ 109	$ 327

Retail Operations

Our retail operations segment, which consists of SouthStar and several businesses that provide energy-related products and services to retail markets, also is weather sensitive and uses a variety of hedging strategies, such as weather derivative instruments and other risk management tools, to mitigate potential weather impacts. For the second quarter of 2013, retail operations' EBIT decreased by $2 million or 14% compared to the second quarter of 2012 and increased by $8 million or 11% for the six months ended June 30, 2013, compared to prior year, as shown in the following table.

In millions	Three months ended	Six months ended
EBIT - for June 30, 2012	$ 14	$ 74
Operating margin		
Increased average customer usage in Georgia due to colder weather relative to prior year, net of weather derivatives	4	14

Increased margin primarily due to January 2013 acquisition of retail service contracts	8	12
Inventory write-down (LOCOM) in 2012	-	3
Decreased margin in Illinois mainly due to timing of revenue recognition associated with fixed bill products	(4)	(2)
Decrease related to increase in transportation and gas costs and lower retail price spreads, partially offset by favorable customer portfolio	-	(10)
Other	(1)	-
Increase in operating margin	7	17
Operating expenses		
Increased expenses primarily due to January 2013 acquisition of retail service contracts	6	9
Increased bad debt expense primarily related to colder weather and higher natural gas prices	2	2
Increased (decreased) payroll, benefits, marketing and other expenses	1	(2)
Increase in operating expenses	9	9
EBIT - for June 30,2013	$ 12	$ 82

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Wholesale Services

Our wholesale services segment is involved in asset management and optimization, storage, transportation, producer and peaking services, natural gas supply, natural gas services and wholesale marketing. EBIT for our wholesale services segment is impacted by volatility in the natural gas market arising from a number of factors, including weather fluctuations and changes in supply or demand for natural gas in different regions of the country. For the three and six months ended June 30, 2013, wholesale services' EBIT increased by $20 million and $16 million, respectively, compared to prior year, as shown in the following table.

In millions	Three months ended	Six months ended
EBIT - for June 30, 2012	$ (9)	$ 10
Operating margin		
Change in commercial activity largely driven by colder weather, increased cash optimization opportunities in the supply constrained northeast corridor and the withdrawal of a portion of the storage inventory economically hedged at the end of 2012	13	32
Storage inventory write-down (LOCOM)	(8)	4
Change in value on storage hedges as a result of decrease in NYMEX natural gas prices	38	12
Change in value on transportation and forward commodity hedges from price movements related to natural gas transportation positions	(35)	(45)
Increase in operating margin	8	3
Operating expenses		
Decreased compensation expense, outside services and other costs	(1)	(2)
Decrease in operating expenses	(1)	(2)
Gain on sale of Compass Energy	11	11
EBIT - for June 30, 2013	$ 11	$ 26

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

In millions	Three months ended June 30, 2013	Three months ended June 30, 2012	Six months ended June 30, 2013	Six months ended June 30, 2012
Commercial activity recognized	$ 6	$ (7)	$ 48	$ 16
Gain (loss) on storage hedges	29	(9)	18	6
(Loss) gain on transportation and forward commodity hedges	(16)	19	(18)	27
Inventory LOCOM adjustment, net of estimated recoveries	(8)	-	(8)	(12)
Operating margin	$ 11	$ 3	$ 40	$ 37

Change in commercial activity The commercial activity at wholesale services includes recognized storage and transportation values which were generated in prior periods, and the impact of prior period hedge gains and losses. Additionally, the commercial activity includes operating margin generated and recognized in the current period. The increase in commercial activity reflects the recognition of operating margin resulting from the withdrawal of storage inventory hedged at the end of 2012 that was included in the storage withdrawal schedule with a value of $27 million as of December 31, 2012 as well as the effects of colder weather and increased cash optimization opportunities related

to certain of our transportation portfolio positions, particularly in the Northeastern United States. As previously discussed, our operating margin opportunities are expected to be lower in 2013 due to continued lower volatility and lower seasonal price spreads associated with our storage portfolio.

Change in storage and transportation hedges Seasonal (storage) and geographical location (transportation) spreads and overall natural gas price volatility continued to remain low relative to historical periods. However, during the second quarter of 2013, a decline in natural gas prices resulted in storage hedge gains as compared to the same period last year. For the first six months of 2013, significant volatility at natural gas delivery points throughout the northeast corridor relative to natural gas delivery constraints in the region, resulted in losses on our transportation positions.

Withdrawal schedule Sequent's expected natural gas withdrawals from storage are presented in the following table along with the operating revenues expected at the time of withdrawal. Sequent's expected operating revenues exclude storage demand charges but are net of the estimated impact of profit sharing under our asset management agreements and reflect the amounts that are realizable in future periods based on the inventory withdrawal schedule and forward natural gas prices at June 30, 2013 and 2012. A portion of Sequent's storage inventory is economically hedged with futures contracts, which results in realization of substantially fixed operating revenues, timing notwithstanding. For more information on Sequent's energy marketing and risk management activities, see Item 7A, "Quantitative and Qualitative Disclosures About Market Risk - Commodity Price Risk" of our 2012 Form 10-K.

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Withdrawal schedule	Total storage (in Bcf) (WACOG $3.26)	Expected operating revenues (1) (in millions)
2013		
Third quarter	28	$ 5
Fourth quarter	20	8
2014		
First quarter	2	1
Total at June 30, 2013	50	$ 14
Total at December 31, 2012	51	$ 27
Total at June 30, 2012	55	$ 47

(1) Represents expected operating revenues from planned storage withdrawals associated with existing inventory positions and could change as Sequent adjusts its daily injection and withdrawal plans in response to changes in future market conditions and forward NYMEX price fluctuations.

Midstream Operations

Our midstream operations segment's primary activity is operating non-utility storage and pipeline facilities including the development, acquisition and operation of high-deliverability underground natural gas storage assets. While this business can also generate additional revenue during times of peak market demand for natural gas storage services, certain of our storage services are covered under medium to long-term contracts at fixed market rates. For the three and six months ended June 30, 2013, midstream operations' EBIT decreased by $2 million and $3 million, respectively, compared to prior year, as shown in the following table.

In millions	Three months ended	Six months ended
EBIT - for June 30, 2012	$ 2	$ 5
Operating margin		
Increased revenues at Golden Triangle as a result of Cavern 2 beginning commercial service in third quarter 2012, partially offset by lower revenues at Jefferson Island as a result of lower subscription rates	-	1
Increase in operating margin	-	1
Operating expenses		
Increased depreciation, property taxes, storage expenses, payroll and outside services largely due to Central Valley and Cavern 2 at Golden Triangle beginning commercial service in 2012	2	5
Increase in operating expenses	2	5
Increase from equity investment in Horizon Pipeline	-	1
EBIT - for June 30, 2013	$ -	$ 2

Cargo Shipping

Our cargo shipping segment's primary activity is transporting containerized freight in the Bahamas and the Caribbean, a region that has historically been characterized by modest market growth and intense competition. Such shipments

consist primarily of southbound cargo such as building materials, food and other necessities for developers, distributors and residents in the region, as well as tourist-related shipments intended for use in hotels and resorts and on cruise ships. The balance of the cargo consists primarily of interisland shipments of consumer staples and northbound shipments of apparel, rum and agricultural products. Other related services, such as inland transportation and cargo insurance, are also provided within the cargo shipping segment. Our cargo shipping segment also includes an equity investment in Triton, a cargo container leasing business. For more information about our investment in Triton, see Note 10 to our Consolidated Financial Statements under Item 8 included in our 2012 Form 10-K.

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For the second quarter of 2013, cargo shipping's EBIT was flat compared to the second quarter of 2012 and increased by $1 million for the six months ended June 30, 2013, compared to prior year, as shown in the following table.

In millions	Three months ended	Six months ended
EBIT - for June 30, 2012	$ (1)	$ -
Operating margin		
TEU volume increased due to market share expansion and modest improvement in economic conditions in our service regions; leverage effect of volume increases on fuel expense	8	13
Decreased TEU rates due to ongoing overcapacity, changes in cargo mix and competitive pressures	(4)	(8)
Other	1	-
Increase in operating margin	5	5
Operating expenses		
Decreased depreciation expense	(1)	(2)
Increased payroll, benefits, outside services and other	5	4
Increase in operating expenses	4	2
Decrease from equity investment income in Triton	(1)	(2)
EBIT - for June 30, 2013	$ (1)	$ 1

Liquidity and Capital Resources

Overview The acquisition of natural gas and pipeline capacity, payment of dividends and funding of working capital needs are our most significant short-term financing requirements. The need for long-term capital is driven primarily by capital expenditures and maturities of long-term debt. The liquidity required to fund our working capital, capital expenditures and other cash needs is primarily provided by our operating activities. Our short-term cash requirements not met with cash from operations are primarily satisfied with short-term borrowings under our commercial paper programs, which are supported by the AGL Credit Facility and the Nicor Gas Credit Facility. Periodically, we raise funds supporting our long-term cash needs from the issuance of long-term debt or equity securities. We regularly evaluate our funding strategy and profile to ensure that we have sufficient liquidity for our short-term and long-term needs in a cost-effective manner. Consistent with this, in May 2013, we issued $500 million in 30-year senior notes with an interest rate of 4.4%.

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

Our financing activities, including long-term and short-term debt and equity, are subject to customary approval or review by state and federal regulatory bodies, including the various commissions of the states in which we conduct business. Certain financing activities we undertake may also be subject to approval by state regulatory agencies. A substantial portion of our consolidated assets, earnings and cash flows 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. Nicor Gas is restricted by regulation in the amount it can dividend or loan to affiliates and is not permitted to make money pool loans to affiliates. Dividends are allowed only to the extent of Nicor Gas' retained earnings balance, which was $480 million at June 30, 2013.

We believe the amounts available to us under our senior notes, AGL Credit Facility and Nicor Gas Credit Facility, through the issuance of debt and equity securities, combined with cash provided by operating activities, will continue to allow us to meet our needs for working capital, pension and retiree welfare benefits, capital expenditures, anticipated debt redemptions, interest payments on debt obligations, dividend payments and other cash needs through the next several years. Our ability to satisfy our working capital requirements and our debt service obligations, or fund planned capital expenditures, will substantially depend upon our future operating performance (which will be affected by prevailing economic conditions), and financial, business and other factors, some of which we are unable to control. These factors include, among others, regulatory changes, the price of and demand for natural gas and operational risks.

As of June 30, 2013 and 2012, and December 31, 2012, we had $79 million, $76 million and $80 million, respectively, of cash and short-term investments held by Tropical Shipping. This cash and investments are not available for use by our other operations unless we repatriate a portion of Tropical Shipping’s earnings in the form of a dividend, and pay a significant amount of United States income tax. See Note 12 to our Consolidated Financial Statements under Item 8 included in our 2012 Form 10-K for additional information on our income taxes.

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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,” in our 2012 Form 10-K for additional information on items that could impact our liquidity and capital resource requirements.

Capital Projects We continue to focus on capital discipline and cost control, while moving ahead with projects and initiatives that we expect will have current and future benefits to us and our customers, provide an appropriate return on invested capital and ensure the safety, reliability and integrity of our utility infrastructure. The following table and discussions provide updates on some of our larger capital projects at our distribution operations segment. These programs update or expand our distribution systems to improve system reliability and meet operational flexibility and growth. Our anticipated expenditures for these programs in 2013 are discussed in “Liquidity and Capital Resources” under the caption ‘Cash Flows from Financing Activities’ in our 2012 Form 10-K.

Dollars in millions STRIDE program	Utility	Expenditures in 2013	Expenditures since project inception	Miles of pipe replaced	Year project began	Anticipated year of completion
Pipeline replacement program	Atlanta Gas Light	$ 76	$ 758	2,663	1998	2013
Integrated System Reinforcement Program	Atlanta Gas Light	10	234	n/a	2009	2013
Integrated Customer Growth Program	Atlanta Gas Light	10	39	n/a	2010	2013
Enhanced infrastructure program	Elizabethtown Gas	1	109	96	2009	(1)
Accelerated infrastructure program	Virginia Natural Gas	11	27	61	2012	2017
Total		$ 108	$ 1,167	2,820		

(1) In July 2012, we filed a request to extend this program and we are currently waiting to hear from the New Jersey BPU. If approved, the program is expected to be completed in 2017. A ruling is expected in the second half of 2013.

Nicor Gas In July 2013, Illinois enacted legislation that provides for infrastructure investment by natural gas utilities serving more than 700,000 customers, Nicor Gas meets these criteria. This bill will allow Nicor Gas to provide more widespread safety and reliability enhancements to its pipelines in a timelier manner than under traditional utility regulation, and pass along lower program costs to our customers. We expect to submit a plan for approval by the Illinois Commission in mid-2014 and begin work in 2015.

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

We expect to file a new $259 million STRIDE program in August 2013, $214 million of which will be for i-SRP related projects and $45 million of which will be for i-CGP related projects. Atlanta Gas Light expects hearings and a decision on the new STRIDE program in the fourth quarter of 2013.

In November 2012, we filed the Integrated Vintage Plastic Replacement Program (i-VPR) with the Georgia Commission, as a new component of STRIDE. If approved, this program would replace aging plastic pipe that was installed primarily in the mid-1960's to the early 1980's. We have identified approximately 3,300 miles of vintage plastic mains in our system that potentially should be considered for expedited replacement over the next 15 - 20 years as it reaches the end of its useful life. However, the initial request to the Georgia Commission is to replace approximately 756 miles over the next three to four years. The estimated cost of the first tranche of pipe to be replaced under i-VPR is $275 million. In July 2013, Atlanta Gas Light and the staff of the Georgia Commission filed a joint stipulation adopting the replacement of the 756 miles over four years at an estimated cost of $275 million. Additional reporting requirements and monitoring by the Georgia Commission Staff were also included in the stipulation. Based on the procedural schedule issued by the Georgia Commission, hearings were held in July 2013, and a decision on the program is expected to be made during the third quarter of 2013.

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

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Virginia Natural Gas In January 2012, Virginia Natural Gas filed SAVE, an accelerated infrastructure replacement program, with the Virginia Commission, which involves replacing aging infrastructure as prioritized through Virginia Natural Gas' distribution integrity management program. SAVE was filed in accordance with a Virginia statute providing a regulatory cost recovery mechanism to recover the costs associated with certain infrastructure replacement programs. The Virginia Commission approved SAVE in June 2012, for a five-year period, which includes a maximum allowance for capital expenditure of $25 million per year, not to exceed $105 million in total. SAVE is subject to annual review by the Virginia Commission. We began recovering costs based on this program through a rate rider that became effective August 1, 2012. In May 2013, we filed our annual SAVE rate update detailing the first year performance and our expected future budget, which is subject to review and approval by the Virginia Commission. Approval of the rate update by the Virginia Commission is expected in August 2013.

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

Credit ratings and outlooks are opinions subject to ongoing review by the rating agencies and may periodically change. The rating agencies regularly review our performance, prospects and financial condition and reevaluate their ratings of our long-term debt and short-term borrowings, our corporate ratings and our ratings outlook. There is no guarantee that a rating will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. A credit rating is not a recommendation to buy, sell or hold securities and each rating should be evaluated independently of other ratings.

Factors we consider important to assessing our credit ratings include our Consolidated Statements of Financial Position leverage, capital spending, earnings, cash flow generation, available liquidity and overall business risks. We do not have any triggering events in our debt instruments that are tied to changes in our specified credit ratings or our stock price and have not entered into any 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 June 30, 2013, and reflects no change from December 31, 2012.

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

Our credit ratings depend largely on our financial performance, and a downgrade in our current ratings, particularly below investment grade, would increase our borrowing costs and could limit our access to the commercial paper market. In addition, we would likely be required to pay a higher interest rate in future financings, and our potential pool of investors and funding sources could decrease.

Default Provisions Our debt instruments and other financial obligations include provisions that, if not complied with, could require early payment or similar actions. Our credit facilities contain customary events of default, including, but not limited to, the failure to comply with certain affirmative and negative covenants, cross-defaults to certain other material indebtedness and a change of control.

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

Our credit facilities each include a financial covenant that requires us to maintain a ratio of total debt to total capitalization of no more than 70% at the end of any fiscal month. However, our goal, subject to extraordinary events such as acquisitions, is to maintain these ratios at levels between 50% and 60%. These ratios, as defined within our debt agreements, include standby letters of credit, performance/surety bonds and exclude accumulated OCI items related to non-cash pension adjustments, other post-retirement benefits liability adjustments and accounting adjustments for cash flow hedges. Adjusting for these items, the following table contains our debt-to-capitalization ratios for the dates presented, which are below the maximum allowed.

	June 30, 2013		December 31, 2012		June 30, 2012	
AGL Credit Facility	54	%	58	%	54	%
Nicor Gas Credit Facility	43		55		43	

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We were in compliance with all of our debt provisions and covenants, both financial and non-financial, for all periods presented.

Our ratio of total debt to total capitalization, on a consolidated basis, is typically greater at the beginning of the Heating Season, as we make additional short-term borrowings to fund our natural gas purchases and meet our working capital requirements. We attempt to maintain our ratio of total debt to total capitalization in a target range of 50% to 60%. Accomplishing this capital structure objective and maintaining sufficient cash flow are necessary to maintain attractive credit ratings. For more information on our default provisions, see Note 6 to our unaudited Condensed Consolidated Financial Statements under Item 1 herein. The components of our capital structure, as calculated from our unaudited Condensed Consolidated Statements of Financial Position, as of the dates indicated are provided in the following table.

	June 30, 2013		December 31, 2012		June 30, 2012	
Short-term debt	7	%	16	%	10	%
Long-term debt	48		43		46	
Total debt	55		59		56	
Equity	45		41		44	
Total capitalization	100	%	100	%	100	%

Cash Flows The following table provides a summary of our operating, investing and financing cash flows for the periods presented.

	Six months ended June 30,		
In millions	2013	2012	Variance
Net cash provided by (used in):			
Operating activities	$ 1,161	$ 1,090	$ 71
Investing activities	(413)	(358)	(55)
Financing activities	(695)	(714)	19
Net increase in cash and cash equivalents	53	18	35
Cash and cash equivalents at beginning of period	131	69	62
Cash and cash equivalents at end of period	$ 184	$ 87	$ 97

Cash Flow from Operating Activities The $71 million increase in cash from operating activities for the six months ended June 30, 2013 compared to the same period in 2012 was primarily related to increased cash provided by (i) net energy marketing receivables and payables, due to higher cash received in the current period related to higher sales volumes at higher prices in December 2012 versus the same period in 2011, (ii) prepaid taxes, due to decreased prepaid positions for federal and state income taxes, and (iii) inventories, net of LIFO liquidation, due to increased LIFO liquidation at Nicor Gas and increased withdrawals at Sequent. This increase in cash provided by operating activities was partially offset by decreased cash provided by receivables, other than energy marketing, due to colder weather in 2013, which resulted in higher volumes primarily at distribution operations and retail operations that will be collected in future periods.

Cash Flow from Investing Activities The $55 million increase in cash flow used in investing activities was a result of $122 million spent to acquire approximately 500,000 service plans during the first quarter of 2013. This increase was partially offset by decreased spending for property, plant and equipment expenditures of $32 million, a net increase in short term investments of $15 million and $12 million from the sale of Compass Energy.

Cash Flow from Financing Activities The decreased use of cash for our financing activities for the six months ended June 30, 2013 compared to the same period in 2012 was primarily the result of our May 2013 issuance of senior notes, partially offset by higher short-term debt payments of $267 million and our April 2013 payment of senior notes.

As of June 30, 2013, our variable-rate debt was 17% of our total debt, compared to 32%, as of December 31, 2012 and 27% as of June 30, 2012. The decrease from December 31, 2012 was primarily due to decreased commercial paper borrowings. As of June 30, 2013, our commercial paper borrowings of $521 million were 62% lower than as of December 31, 2012, primarily a result of our repayment of a portion of AGL Capital’s commercial paper borrowings and no commercial paper borrowings under the Nicor Gas Credit Facility. For more information on our debt, see Note 6 to our unaudited Condensed Consolidated Financial Statements under Item 1 herein.

In April 2013, our $225 million 4.45% senior notes matured. Repayment of these senior notes was funded through our commercial paper program. In May 2013, we issued $500 million in 30-year senior notes. The net proceeds of $494 million were used to repay a portion of AGL Capital’s commercial paper, including $225 million we borrowed to repay our senior notes that matured in April 2013.

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Short-term Debt Our short-term debt comprises borrowings under our commercial paper programs and current portions of our senior notes and capital leases. The following table provides additional information on our short-term debt.

In millions	Period end balance outstanding (1)	Daily average balance outstanding (2)	Minimum balance outstanding (2)	Largest balance outstanding (2)
Commercial paper - AGL Capital	$ 521	$ 838	$ 380	$ 1,064
Commercial paper - Nicor Gas	-	74	-	314
Senior notes	-	129	-	225
Capital leases	-	1	-	1
Total short-term debt and current portions of long-term debt and capital leases	$ 521	$ 1,042	$ 380	$ 1,604

(1) As of June 30, 2013.

(2) For the six months ended June 30, 2013. The minimum and largest balances outstanding for each short-term debt instrument occurred at different times during the period. Consequently, the total balances are not indicative of actual borrowings on any one day during the period.

The largest, minimum and daily average balances borrowed under our commercial paper programs are important when assessing the intra-period fluctuations of our short-term borrowings and potential liquidity risk. The fluctuations are due to our seasonal cash requirements to fund working capital needs, in particular the purchase of natural gas inventory.

Increasing natural gas commodity prices can have a significant impact on our commercial paper borrowings. Based on current natural gas prices and our expected injection plan, a $1 increase NYMEX price change could result in a $104 million change of working capital requirements during the injection season. This range is sensitive to the timing of storage injections and withdrawals, collateral requirements and our portfolio position. Based on current natural gas prices and our expected purchases during the upcoming injection season, we believe that we have sufficient liquidity to cover our working capital needs for the upcoming Heating Season.

The lenders under our credit facilities and lines of credit are major financial institutions with $2.2 billion of committed balances and all had investment grade credit ratings as of June 30, 2013. It is possible that one or more lending commitments could be unavailable to us if the lender defaulted due to lack of funds or insolvency. However, based on our current assessment of our lenders' creditworthiness, we believe the risk of lender default is minimal.

Long-term Debt Our long-term debt matures more than one year from June 30, 2013, and consists of medium-term notes: Series A, Series B, and Series C, which we issued under an indenture during December 1989; senior notes; first mortgage bonds; and gas facility revenue bonds.

During the first quarter of 2013, we refinanced $200 million of our outstanding tax-exempt gas facility revenue bonds, $180 million of which were previously issued by the New Jersey Economic Development Authority and $20 million of which were previously issued by Brevard County, Florida. The refinancing involved a combination of the issuance of $60 million of refunding bonds to and the purchase of $140 million of existing bonds by a syndicate of banks. Our relationship with the syndicate of banks regarding the bonds is governed by an agreement that contains representations, warranties, covenants and default provisions consistent with those contained in similar financing documents of ours. All of the bonds remain floating-rate instruments and we anticipate interest expense savings of approximately $2 million annually over the 5.5 year term of the agreement. AGL Resources had no cash receipts or payments in connection with the refinancing. The letters of credit providing credit support for the retired bonds along

with other related agreements were terminated as a result of the refinancing. Costs associated with these refinancings will be amortized over the remaining life of the bonds.

Noncontrolling Interest We recorded cash distributions for SouthStar's dividend distributions to Piedmont of $17 million for the six months ended June 30, 2013 and $14 million for the same period in 2012. The primary reason for the increase in the distribution to Piedmont during the current year was increased earnings for 2012 compared to 2011.

Dividends on Common Stock Our common stock dividend payments were $111 million for the six months ended June 30, 2013 and $96 million for the same period in 2012. The increase is primarily due to the $0.10 stub period dividend paid in December 2011, which reduced the dividend paid in the first quarter of 2012 by the same amount and the annual dividend increase of $0.04 per share.

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

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Other than the changes in our debt, see Note 6 to our unaudited Condensed Consolidated Financial Statements under Part I, Item 1 herein, there were no significant changes to our contractual obligations described in Note 11 to our Consolidated Financial Statements and related notes as filed in Item 8 of our 2012 Form 10-K.

Pension and retiree welfare plan obligations Primarily as a result of merging our pension plans in December 2012, no contributions were required during the six months ended June 30, 2013. During the first half of 2012, we contributed $24 million to certain of our qualified pension plans and an additional $8 million in July 2012 for a total of $32 million through July 2012. Based on the current funding status of our merged pension plan, we do not believe additional contributions to the pension plan will be required during 2013.

During the six months ended June 30, 2013, we recorded net periodic benefit costs of $28 million related to our defined benefit plans compared to $31 million during the same period last year. During the second quarter of 2013, we received a final computation of the 2013 expense that reflects January 1, 2013 census data. The final annual expense is expected to be $57 million, before capitalization, for 2013 compared to actual expense of $61 million for 2012. We estimate that during the remainder of 2013 we will record net periodic benefit costs of $29 million.

Critical Accounting Policies and Estimates

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

Each of our critical accounting 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 estimates from those disclosed in our Management’s Discussion and Analysis of Financial Condition and Results of Operations as filed on our 2012 Form 10-K. Our critical accounting estimates used in the preparation of our unaudited Condensed Consolidated Financial Statements include the following:

- Regulatory Infrastructure Program Liabilities
- Environmental Remediation Liabilities
- Derivatives and Hedging Activities
- Goodwill and Intangible Assets
- Contingencies
- Pension and Retiree Welfare Plans
- Income Taxes

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

We are exposed to risks associated with natural gas prices, interest rates, credit and fuel prices. Natural gas price risk is defined as the potential loss that we may incur as a result of changes in the fair value of natural gas. Interest rate risk results from our portfolio of debt and equity instruments that we issue to provide financing and liquidity for our business. Credit risk results from the extension of credit throughout all aspects of our business, but is particularly concentrated at Atlanta Gas Light in distribution operations and in wholesale services. Our fuel price risk is primarily in cargo shipping, which is partially reduced through fuel surcharges. Our use of derivative instruments is governed by a risk management policy, approved and monitored by our Risk Management Committee (RMC).

Our RMC is responsible for establishing the overall risk management policies and monitoring compliance with, and adherence to, the terms within these policies, including approval and authorization levels and delegation of these levels. Our RMC consists of members of senior management who monitor open natural gas price risk positions and other types of risk, corporate exposures, credit exposures and overall results of our risk management activities. It is chaired by our chief risk officer, who is responsible for ensuring that appropriate reporting mechanisms exist for the RMC to perform its monitoring functions. Our risk management activities and related accounting treatment for our derivative instruments are described in further detail in Note 4 of our unaudited Condensed Consolidated Financial Statements.

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Natural Gas Price Risk

The following tables include the fair values and average values of our consolidated derivative instruments as of the dates indicated. We base the average values on monthly averages for the six months ended June 30, 2013 and 2012.

	Derivative instruments average values at June 30, (1)	
In millions	2013	2012
Asset	$ 107	$ 257
Liability	36	116

(1) Excludes cash collateral amounts.

	Derivative instruments fair values netted with cash collateral at		
In millions	June 30, 2013	December 31, 2012	June 30, 2012
Asset	$ 130	$ 144	$ 226
Liability	39	39	66

The following table illustrates the change in the net fair value of our derivative instruments during the periods presented, and provides details of the net fair value of contracts outstanding as of the dates presented.

	Three months ended June 30,		Six months ended June 30,	
In millions	2013	2012	2013	2012
Net fair value of derivative instruments outstanding at beginning of period	$ 10	$ (46)	$ 36	$ 30
Derivative instruments realized or otherwise settled during period	(15)	46	(46)	(18)
Net fair value of derivative instruments acquired during period	-	-	-	3
Change in net fair value of derivative instruments	2	23	7	8
Net fair value of derivative instruments outstanding at end of period	(3)	23	(3)	23
Netting of cash collateral	94	137	94	137
Cash collateral and net fair value of derivative instruments outstanding at end of period	$ 91	$ 160	$ 91	$ 160

The sources of our net fair value at June 30, 2013, are as follows.

In millions	Prices actively quoted	Significant other observable

	(Level 1) (1)	inputs (Level 2) (2)
Mature through 2013	$ 3	$ 17
Mature 2014 - 2015	(46)	24
Mature 2016 - 2017	(3)	2
Total derivative instruments (3)	$ (46)	$ 43

(1) Valued using NYMEX futures prices.

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

(3) Excludes cash collateral amounts.

Value at risk Value at risk is 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. Our open exposure is managed in accordance with established policies that limit market risk and require daily reporting of potential financial exposure to senior management, including the chief risk officer. Because we generally manage physical gas assets and economically protect our positions by hedging in the futures markets, our open exposure is generally immaterial, permitting us to operate within relatively low VaR limits. We employ daily risk testing, using both VaR and stress testing, to evaluate the risks of our open positions. Our VaR is determined on a 95% confidence interval and a 1-day holding period. In simple terms, this means that 95% of the time, the risk of loss from a portfolio of positions is expected to be less than or equal to the amount of VaR calculated.

We actively monitor open commodity positions and the resulting VaR. We also continue to maintain a relatively matched book, where our total buy volume is close to our sell volume, with minimal open natural gas price risk. Based on a 95% confidence interval and employing a 1-day holding period for all positions, our portfolio positions for the periods presented had the following VaRs.

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	Three months ended June 30,		Six months ended June 30,	
In millions	2013	2012	2013	2012
Period end	$ 1.7	$ 1.9	$ 1.7	$ 1.9
Average	1.8	2.4	1.8	2.5
High	2.2	3.6	2.6	4.8
Low	1.2	1.7	1.2	1.7

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 $0.7 billion of variable-rate debt outstanding at June 30, 2013, a 100 basis point change in market interest rates would have resulted in an increase in pre-tax interest expense of $7 million on an annualized basis.

We use interest rate swaps to help us achieve our desired mix of variable to fixed-rate debt. Our variable-rate debt target generally ranges from 20% to 45% of total debt. We also may use forward-starting interest rate swaps and interest rate lock agreements to lock in fixed interest rates on our forecasted issuances of debt. The objective of these hedges is to offset the variability of future payments associated with the interest rate on debt instruments we expect to issue.

We have $300 million of 6.4% senior notes due in July 2016. In May 2011, we entered into interest rate swaps related to these senior notes to effectively convert $250 million from a fixed-rate to a variable-rate obligation. On September 6, 2012, we settled this $250 million interest rate swap, which resulted in our receipt of a $17 million cash payment.

On May 16, 2013, we issued $500 million of 30-year senior notes with an interest rate of 4.4%. We had entered into $300 million, in notional amount, of fixed-rate forward-starting interest rate swaps to hedge the first ten years of potential interest rate volatility prior to this issuance. The weighted average interest rate of these swaps was a 10-year United States Treasury rate of 1.85%. On May 16, 2013, we settled these swaps, which resulted in our receipt of a $6 million cash payment.

The gain or loss on the interest rate swaps designated as cash flow hedges is generally deferred in accumulated OCI until settlement, at which point it is amortized to interest expense over the period of the related hedged interest payments. For additional information, see Note 4 to our unaudited Condensed Consolidated Financial Statements under Item 1 herein.

Credit Risk

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

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

We have a concentration of credit risk as measured by our 30-day receivable exposure plus forward exposure. As of June 30, 2013, our top 20 counterparties represented approximately 55% of the total counterparty exposure of $377 million, derived by adding together the top 20 counterparties' exposures, exclusive of customer deposits, and dividing by the total of our counterparties' exposures.

As of June 30, 2013, our counterparties, or the counterparties' guarantors, had a weighted average S&P equivalent credit rating of A-, which is an improvement from the prior year. The S&P equivalent credit rating is determined by a process of converting the lower of the S&P or Moody's ratings to an internal rating ranging from 9 to 1, with 9 being equivalent to AAA/Aaa by S&P and Moody's and 1 being D or Default by S&P and Moody's. A counterparty that does not have an external rating is assigned an internal rating based on the strength of the financial ratios of that counterparty. To arrive at the weighted average credit rating, each counterparty is assigned an internal ratio, which is multiplied by their credit exposure and summed for all counterparties. The sum is divided by the aggregate total counterparties' exposures, and this numeric value is then converted to an S&P equivalent. The following table shows our third-party natural gas contracts receivable and payable positions.

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In millions	Gross receivables June 30, 2013	Gross receivables December 31, 2012	Gross receivables June 30, 2012	Gross payables June 30, 2013	Gross payables December 31, 2012	Gross payables June 30, 2012
Netting agreements in place:						
Counterparty is investment grade	$ 206	$ 485	$ 266	$ 107	$ 282	$ 186
Counterparty is non-investment grade	1	9	9	7	13	11
Counterparty has no external rating	396	175	70	514	315	185
No netting agreements in place:						
Counterparty is investment grade	5	7	2	-	1	1
Counterparty has no external rating	-	1	-	-	-	-
Amount recorded on unaudited Condensed Consolidated Statements of Financial Position	$ 608	$ 677	$ 347	$ 628	$ 611	$ 383

We have certain trade and credit contracts that have explicit minimum credit rating requirements. These credit rating requirements typically give counterparties the right to suspend or terminate credit if our credit ratings are downgraded to non-investment grade status. Under such circumstances, we would need to post collateral to continue transacting business with some of our counterparties. If such collateral were not posted, our ability to continue transacting business with these counterparties would be impaired. If our credit ratings had been downgraded to non-investment grade status, the required amounts to satisfy potential collateral demands under such agreements with our counterparties would have totaled $16 million at June 30, 2013, which would not have a material impact on our consolidated results of operations, cash flows or financial condition.

There have been no significant changes to our credit risk related to any of our segments other than wholesale services, as described in Item 7A ”Quantitative and Qualitative Disclosures about Market Risk” of our 2012 Form 10-K.

Fuel Price Risk

Cargo Shipping Tropical Shipping’s objective is to reduce its exposure to higher fuel costs through fuel surcharges. However, these fuel surcharges do not remove our entire risk in periods of increasing fuel prices and volatility, or increased competition, and any relief may not be realized in the same period as the cost incurred. An increase of 10% in Tropical Shipping’s average cost per gallon for vessel fuel results in approximately $6 million in additional annual fuel expense. Fuel surcharges would be implemented to reduce the impact of the increased fuel expense.

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 under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act), as of June 30, 2013, 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 June 30, 2013, 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 that occurred during the second quarter ended June 30, 2013, 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. In addition, we are party, as both plaintiff and defendant, to a number of lawsuits related to our business on an ongoing basis. Management believes that the outcome of all regulatory proceedings and litigation in which we are currently involved will not have a material adverse effect on our consolidated financial condition. For more information regarding some of these proceedings, see Note 9 to our unaudited Condensed Consolidated Financial Statements under the caption “Litigation.”

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Item 1A. Risk Factors.

For information regarding our risk factors, see the factors discussed in Part I, "Item 1A. Risk Factors" in our 2012 Form 10-K, which could materially affect our business, financial condition or future results. The risks described in our 2012 Form 10-K are not the only risks facing our Company. Additional risks and uncertainties not currently known to us or that we currently do not recognize as material also may materially adversely affect our business, financial condition or future results. The following risk factor has changed since filing our 2012 Form 10-K.

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

Climate change is expected to receive increasing attention from the current federal administration, non-governmental organizations, and legislators. Debate continues as to the extent to which our climate is changing, the potential causes of any change, and its potential impacts. Some attribute global warming to increased levels of greenhouse gases, including carbon dioxide, which has led to significant legislative and regulatory efforts to limit greenhouse gas emissions.

Presently, there are no federally mandated greenhouse gas reduction requirements that directly affect our operations. However, the United States Environmental Protection Agency (EPA) has begun using provisions of the Clean Air Act to regulate greenhouse gas emissions, including carbon dioxide. Thus far, EPA has imposed greenhouse gas regulations on automobiles and implemented new permitting requirements for the construction or modification of major stationary sources of greenhouse gas emissions, including natural gas-fired power plants.

In addition, President Obama issued a Presidential Memorandum on June 25, 2013, directing EPA to adopt performance standards to regulate greenhouse gas emissions from power plants. Specifically, the Presidential Memorandum directs EPA to propose standards for future power plants by September 20, 2013 (to replace a proposal EPA published in April 2012), and propose emission guidelines for modified, reconstructed, and existing power plants by June 1, 2014. The Presidential Memorandum directs EPA to finalize those regulations by June 1, 2015. It also includes a wide variety of other initiatives designed to reduce greenhouse gas emissions, prepare for the impacts of climate change, and lead international efforts to address climate change.

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

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

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

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

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

There were no purchases of our common stock by us or any affiliated purchasers during the second quarter of 2013 and no unregistered sales of equity securities were made during this period.

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Item 6. Exhibits.

4.1a	Form of AGL Capital Corporation 4.40% Senior Notes due 2043 (Exhibit 4.2, AGL Resources Inc. Form 8-K filed May 16, 2013).
4.1b	Guarantee of AGL Resources Inc. dated as of May 16, 2013 regarding the AGL Capital Corporation 4.40% Senior Notes due 2043 (Exhibit 4.3, AGL Resources Inc. Form 8-K filed May 16, 2013).
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.
101.SCH	XBRL Taxonomy Extension Schema.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.
101.DEF	XBRL Taxonomy Definition Linkbase.
101.LAB	XBRL Taxonomy Extension Labels Linkbase.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.

Glossary of Key Terms

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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: July 31, 2013 /s/ Andrew W. Evans
Executive Vice President and Chief Financial Officer

Glossary of Key Terms

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