AGL RESOURCES INC
Form 10-K/A
November 07, 2014

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

FORM 10-K/A
Amendment No. 1

ANNUAL REPORT PURSUANT TO SECTION 13 OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2013

Commission File Number 1-14174

AGL RESOURCES INC.
Ten Peachtree Place NE,
Atlanta, Georgia 30309
404-584-4000

Georgia	58-2210952
(State of incorporation)	(I.R.S. Employer Identification No.)

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

Title of each class	Name of each exchange on which registered
Common Stock, $5 Par Value	New York Stock Exchange

AGL Resources Inc. is a well-known seasoned issuer.

AGL Resources Inc. is required to file reports pursuant to Section 13 of the Securities Exchange Act.

AGL Resources Inc.: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act during the preceding 12 months, and (2) has been subject to such filing requirements for the past 90 days.

AGL Resources Inc. has submitted electronically and posted on its corporate website every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months.

AGL Resources Inc. believes that during the 2013 fiscal year, its executive officers, directors and 10% beneficial owners subject to Section 16(a) of the Securities Exchange Act complied with all applicable filing requirements, except as set forth under the caption “Section 16(a) Beneficial Ownership Reporting Compliance” in AGL Resources Inc.’s Proxy Statement for the 2014 Annual Meeting of Shareholders.

AGL Resources Inc. is a large accelerated filer and is not a shell company.

The aggregate market value of AGL Resources Inc.'s common stock held by non-affiliates of the registrant (based on the closing sale price on June 29, 2013, as reported by the New York Stock Exchange), was $5,081,511,045.

The number of shares of AGL Resources Inc.'s common stock outstanding as of January 31, 2014 was 118,901,889

TABLE OF CONTENTS

2

Unless the context requires otherwise, references to “we,” “us,” “our,” the “company” or “AGL Resources” mean consolidated AGL Resources Inc. and its subsidiaries.

Explanatory Note:

We are filing this Amendment No. 1 on Form 10-K/A (this “Amended Filing”) to our Annual Report on Form 10-K for the year ended December 31, 2013 (the “Original Filing”), to: (i) reissue the Report of Independent Registered Public Accounting Firm to update the firm’s opinion regarding the effectiveness of our internal control over financial reporting as of December 31, 2013; (ii) revise management’s conclusions regarding internal control over financial reporting and disclosure controls and procedures as of December 31, 2013; (iii) revise the financial statements to adjust certain amounts in the accounting for revenue recognition related to certain of our regulatory infrastructure programs since 1998 and adjust our amortization of intangible assets for our customer relationships and trade names for the years ended December 31, 2013 and 2012, as well as update other previously-identified immaterial adjustments. Accordingly, we hereby amend and replace in their entirety Items 6, 7, 8, 9A and 15 in the Original Filing.

Additionally, we are recasting certain prior period information in our Annual Report on Form 10-K for the year ended December 31, 2013 to conform with segment reporting changes made in connection with the sale of our Tropical Shipping business, as a result of entering into a definitive agreement to sell this business on April 4, 2014. We concluded that this divestiture qualified for discontinued operations treatment of this business during the second quarter of 2014. Accordingly, the operations and cash flows of this business were removed from our ongoing operations and the assets and liabilities of this business were classified as held for sale, as reported in our Quarterly Report on Form 10-Q for the quarter ended June 30, 2014.

We did not maintain effective controls to appropriately apply the accounting guidance related to the recognition of allowed versus incurred costs. Specifically, the Company did not have controls to address the recognition of allowed versus incurred costs, primarily related to an allowed equity return, applied to the accounting for our regulated infrastructure programs and related disclosures that operated at a level of precision to prevent or detect potential material misstatements to the Company’s consolidated financial statements. This control deficiency resulted in the misstatement of our regulatory assets and operating revenues and related financial disclosures and resulted in the revision of our consolidated financial statements for the years December 31, 2013, 2012 and 2011 and each of the quarters of March 31, 2014 and June 30, 2014. Additionally, this control deficiency could result in misstatements of the aforementioned accounts and disclosures that would result in a material misstatement of the consolidated financial statements that would not be prevented or detected. Accordingly, our management has concluded that the control deficiency constitutes a material weakness.

As required by Rule 12b-15, our principal executive officer and principal financial officer are providing updated certifications. In addition, we are filing a new consent of PricewaterhouseCoopers LLP. Accordingly, we hereby amend Item 15 in the Original Filing to reflect the filing of the new certifications and consent.

Except as indicated above, this Amended Filing does not purport to reflect any information or events subsequent to the filing date of the Original Filing. As such, this Amended Filing speaks only as of the date the Original Filing was filed, and we have not undertaken herein to amend, supplement or update any information contained in the Original Filing to give effect to any subsequent events. Accordingly, this Amended Filing should be read in conjunction with the Original Filing and any documents filed by us with the Securities and Exchange Commission (SEC) subsequent to the Original Filing, including our Quarterly Report on Form 10-Q for the quarter ended March 31, 2014, filed with the SEC on April 29, 2014, and our Quarterly Report on Form 10-Q for the quarter ended June 30, 2014, filed with the SEC on July 30, 2014.

3

GLOSSARY OF KEY TERMS

AFUDC	Allowance for funds used during construction, which represents the estimated cost of funds, from both debt and equity sources, used to finance the construction of major projects and is capitalized in rate base for ratemaking purposes when the completed projects are placed in service
AGL Capital	AGL Capital Corporation
AGL Credit Facility	$1.3 billion credit agreement entered into by AGL Capital to support the AGL Capital commercial paper program
AGL Resources	AGL Resources Inc., together with its consolidated subsidiaries
Atlanta Gas Light	Atlanta Gas Light Company
Bcf	Billion cubic feet
Central Valley	Central Valley Gas Storage, LLC
Chattanooga Gas	Chattanooga Gas Company
Chicago Hub	A venture of Nicor Gas, which provides natural gas storage and transmission-related services to marketers and gas distribution companies
California Commission	California Public Utilities Commission, the state regulatory agency for Central Valley
Compass Energy	Compass Energy Services, Inc., which was sold in 2013
EBIT	Earnings before interest and taxes, the primary measure of our operating segments’ profit or loss, which includes operating income and other income and excludes financing costs, including interest on debt and income tax expense
EPA	U.S. Environmental Protection Agency
ERC	Environmental remediation costs associated with our distribution operations segment that are generally recoverable through rate mechanisms
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings
GAAP	Accounting principles generally accepted in the United States of America
Georgia Commission	Georgia Public Service Commission, the state regulatory agency for Atlanta Gas Light
Georgia Natural Gas	The trade name under which SouthStar does business in Georgia
Golden Triangle	Golden Triangle Storage, Inc.
Heating Degree Days	A measure of the effects of weather on our businesses, calculated when the average daily temperatures are less than 65 degrees Fahrenheit
Heating Season	The period from November through March when natural gas usage and operating revenues are generally higher
Henry Hub	A major interconnection point of natural gas pipelines in Erath, Louisiana where NYMEX natural gas future contracts are priced
Illinois Commission	Illinois Commerce Commission, the state regulatory agency for Nicor Gas
Jefferson Island	Jefferson Island Storage & Hub, LLC
LIBOR	London Inter-Bank Offered Rate
LIFO	Last-in, first-out
LNG	Liquefied natural gas
LOCOM	Lower of weighted average cost or current market price
Marketers	

	Marketers selling retail natural gas in Georgia and certificated by the Georgia Commission
MGP	Manufactured gas plant
Moody’s	Moody’s Investors Service
New Jersey BPU	New Jersey Board of Public Utilities, the state regulatory agency for Elizabethtown Gas
Nicor	Nicor Inc. - an acquisition completed in December 2011 and former holding company of Nicor Gas
Nicor 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
NUI	NUI Corporation
NYMEX	New York Mercantile Exchange, Inc.
OCI	Other comprehensive income
Operating margin	A non-GAAP measure of income, calculated as operating revenues minus cost of goods sold and revenue tax expense
OTC	Over-the-counter
Pad gas	Volumes of non-working natural gas used to maintain the operational integrity of the natural gas storage facility, also known as base gas
PBR	Performance-based rate, a regulatory plan at Nicor Gas that provided economic incentives based on natural gas cost performance. The plan terminated in 2003
PGA	Purchased Gas Adjustment
Piedmont	Piedmont Natural Gas Company, Inc.
Pivotal Home Solutions	Nicor Energy Services Company, doing business as Pivotal Home Solutions
Pivotal Utility	Pivotal Utility Holdings, Inc., doing business as Elizabethtown Gas, Elkton Gas and Florida City Gas
PP&E	Property, plant and equipment
S&P	Standard & Poor’s Ratings Services
Sawgrass Storage	Sawgrass Storage, LLC
SEC	Securities and Exchange Commission
Sequent	Sequent Energy Management, L.P.
Seven Seas	Seven Seas Insurance Company, Inc.
SNG	Substitute natural gas, a synthetic form of gas manufactured from coal
SouthStar	SouthStar Energy Services LLC
STRIDE	Atlanta Gas Light’s Strategic Infrastructure Development and Enhancement program
Tennessee Authority	Tennessee Regulatory Authority, the state regulatory agency for Chattanooga Gas
Term Loan Facility	$300 million credit agreement entered into by AGL Capital to repay the $300 million senior notes that matured in 2011
TEU	Twenty-foot equivalent unit, a measure of volume in containerized shipping equal to one 20-foot-long container
Triton	Triton Container Investments LLC
Tropical Shipping	Tropical Shipping and Construction Company Limited, and also the name used throughout this filing to describe the business operations of our former cargo shipping segment (excluding Triton), which now has been classified as discontinued operations and held for sale
U.S.	United States
VaR	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.
Virginia Natural Gas	Virginia Natural Gas, Inc.
Virginia Commission	Virginia State Corporation Commission, the state regulatory agency for Virginia Natural Gas
WACOG	Weighted average cost of gas
WNA	Weather normalization adjustment

PART II

ITEM 6. REVISED SELECTED FINANCIAL DATA

Selected financial data about AGL Resources for the last five years is set forth in the table below. You should read the data in the table in conjunction with the consolidated financial statements and related notes set forth in Item 8, “Financial Statements and Supplementary Data.” Material changes from 2011 to 2012 are primarily due to the Nicor merger which closed on December 9, 2011.

Dollars and shares in millions, except per share amounts	2013(1) Revised	2012 (1) Revised	2011 (1)(2) Revised	2010 (2)(3)	2009 (2)(3)
Income statement data					
Operating revenues	$4,209	$3,562	$2,305	$2,373	$2,317
Operating expenses					
Cost of goods sold	2,110	1,583	1,085	1,164	1,142
Operation and maintenance (4)	887	816	497	497	497
Depreciation and amortization	397	394	182	160	158
Nicor merger expenses (4)	-	20	57	6	-
Taxes other than income taxes	187	159	57	46	44
Total operating expenses	3,581	2,972	1,878	1,873	1,841
Gain on disposition of assets	11	-	-	-	-
Operating income	639	590	427	500	476
Other income (expense)	16	24	7	(1)	9
EBIT	655	614	434	499	485
Interest expense, net	170	183	134	109	101
Income before income taxes	485	431	300	390	384
Income tax expense	177	157	121	140	135
Income from continuing operations	308	274	179	250	249
Income from discontinued operations, net of tax	5	1	-	-	-
Net income	313	275	179	250	249
Less net income attributable to the noncontrolling interest	18	15	14	16	27
Net income attributable to AGL Resources Inc.	$295	$260	$165	$234	$222
Per common share information					
Diluted weighted average common shares outstanding	118.3	117.5	80.9	77.8	77.1
Diluted earnings per common share (5)					
Continuing operations	$2.45	$2.20	$2.04	$3.00	$2.88
Discontinued operations	0.04	0.01	-	-	-
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	$2.49	$2.21	$2.04	$3.00	$2.88
Dividends declared per common share	$1.88	$1.74	$1.90	$1.76	$1.72
Dividend payout ratio	76 %	79 %	93 %	58 %	60 %
Dividend yield (6)	4.0 %	4.4 %	4.5 %	4.9 %	4.7 %
Price range:					

High	$49.31	$42.88	$43.69	$40.08	$37.52
Low	$38.86	$36.59	$34.08	$34.21	$24.02
Close (7)	$47.23	$39.97	$42.26	$35.85	$36.47
Market value (7)	$5,615	$4,711	$4,946	$2,800	$2,826
Statements of Financial Position data (7)					
Total assets	$14,550	$14,070	$13,862	$7,481	$7,045
Property, plant and equipment – net	8,643	8,205	7,741	4,396	4,146
Short-term debt	1,171	1,377	1,321	733	602
Long-term debt	3,813	3,553	3,578	1,971	1,974
Total debt	4,984	4,930	4,899	2,704	2,576
Total equity	3,613	3,391	3,305	1,836	1,819
Financial ratios (7)					
Debt	58 %	59 %	60 %	60 %	59 %
Equity	42 %	41 %	40 %	40 %	41 %
Total	100 %	100 %	100 %	100 %	100 %
Return on average equity	8.4 %	7.8 %	6.4 %	12.8 %	12.7 %

(1) Amounts revised for prior period adjustments. See Note 15 to our Consolidated Financial Statements under Part II, Item 8 herein for additional information.

(2) Material changes from 2011 to 2012 are primarily due to the Nicor merger on December 9, 2011. Tropical Shipping was acquired in the Nicor merger, therefore, there were no changes as a result of the September 2014 divestiture to 2010 or 2009.

(3) Income statement data does not reflect adjustments, as discussed in Note 15 to our Consolidated Financial Statements under Part II, Item 8 herein as they were inconsequential to these years. However, we have revised total assets and property, plant and equipment, net.

(4) Transaction expenses associated with the Nicor merger were excluded from operation and maintenance expenses and presented separately.

(5) Excludes net income attributable to the noncontrolling interest.

(6) Dividends declared per common share during the fiscal period divided by market value per common share as of the last day of the fiscal period.

(7) As of the last day of the fiscal period.

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

Executive Summary

We are 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 complementary to the distribution of natural gas. Our operating segments consist of the following four operating and reporting segments – distribution operations, retail operations, wholesale services and midstream operations and one non-operating segment - other. These segments are consistent with how management views and operates our business. Amounts shown in this Item 7, unless otherwise indicated, exclude assets held for sale and discontinued operations. See Note 14 under Item 8 for additional information. The following table provides certain information on our segments.

	EBIT (1)			Assets (1)			Capital Expenditures (1)		
	2013	2012	2011	2013	2012	2011	2013	2012	2011
Distribution operations	84 %	84 %	93 %	82 %	82 %	81 %	93 %	84 %	85 %
Retail operations	20	18	21	5	4	4	1	1	1
Wholesale services	-	-	1	8	9	9	-	-	-
Midstream operations	(2)	2	2	5	5	5	2	8	8
Other/intercompany eliminations	(2)	(4)	(17)	-	-	1	4	7	6
Total	100 %	100 %	100 %	100 %	100 %	100 %	100 %	100 %	100 %

(1) Amount includes prior period adjustments. See Note 15 to our Consolidated Financial Statements under Part II, Item 8 herein for additional information.

In the third quarter of 2014, we adjusted the accounting treatment for our previously-reported non-cash revenue recognition associated with our regulatory infrastructure programs. The adjustments did not affect previously-reported operating cash flows, nor are they expected to affect capital expenditure plans or dividend payments. The infrastructure replacement programs are expected to generate the same levels of return as previously communicated, as all amounts will be recovered in accordance with allowed recovery mechanisms. The adjustment relates only to the timing of recognition and does not impact rates charged to customers. These adjustments impacted our distribution operations segment. Additionally, we adjusted the amortization of intangible assets for customer relationships and trade names in our retail operations segment to reflect the amortization expense on a basis consistent with the pattern of undiscounted cash flows used to determine their fair values. See Note 15 to our Consolidated Financial Statements under Part II, Item 8 herein for additional information on these adjustments. As indicated in the tables below, these adjustments resulted in the following impact to our previously reported results for distribution operations and retail operations.

	2013			2012			2011		
In millions	Operating margin (1) (2)	Operating expenses (2)	EBIT (1)	Operating margin (1) (2)	Operating expenses (2) (3)	EBIT (1)	Operating margin (1) (2)	Operating expenses (2)	EBIT (1)
Distribution operations									
As filed	$ 1,660	$ 1,093	$ 582	$ 1,571	$ 1,048	$ 532	$ 963	$ 557	$ 412
Adjustment	(45)	(10)	(36)	(19)	(4)	(15)	(13)	(2)	(11)
Revised	$ 1,615	$ 1,083	$ 546	$ 1,552	$ 1,044	$ 517	$ 950	$ 555	$ 401

Retail operations									
As filed	$ 294	$ 157	$ 137	$ 247	$ 131	$ 116	$ 168	$ 75	$ 93
Adjustment	-	5	(5)	-	5	(5)	-	-	-
Revised	$ 294	$ 162	$ 132	$ 247	$ 136	$ 111	$ 168	$ 75	$ 93

(1) Amount includes prior period adjustments. See Note 15 to our Consolidated Financial Statements under Part II, Item 8 herein for additional information.
(2) Operating margin is a non-GAAP measure. A reconciliation of operating revenue and operating margin to operating income, and EBIT to income before income taxes and net income is contained in "Results of Operations" herein. See Note 13 to our Consolidated Financial Statements under Part II, Item 8 herein for additional segment information.
(3) Operating margin and operating expenses are adjusted for revenue tax expenses which are passed directly through to our customers.

On April 4, 2014 we entered into a definitive agreement to sell Tropical Shipping, which historically operated within our cargo shipping segment. We closed the sale of Tropical Shipping in September 2014. The operations of Tropical Shipping have been classified as discontinued operations in our consolidated financial statements, and the business is no longer treated as a separate segment for financial reporting purposes. Accordingly, in this Management's Discussion and Analysis of Financial Condition and Results of Operations, all references to continuing operations exclude assets held for sale and discontinued operations. Cargo shipping also included our investment in Triton, which was not a part of the sale and has been reclassified into our other segment. The sale of Tropical Shipping will allow us to focus on growing our core business of operating regulated utilities and complementary non-regulated energy businesses and provide us with flexibility around our long-term financing plans. For additional information on our discontinued operations, see Note 14 to our Consolidated Financial Statements under Part II, Item 8 herein for additional segment information.

In 2013, our net income attributable to AGL Resources Inc. was $295 million, an increase of $35 million compared to 2012 as we benefited from colder-than-normal weather as compared to the historically warm weather in 2012. Excluding weather, we achieved growth in our operating margins during 2013 primarily as a result of contributions from our regulatory infrastructure programs in distribution operations, targeted acquisition growth in retail operations and significant improvement in commercial activity in our wholesale services, as well as the gain on the sale of Compass Energy, offset by mark-to-market accounting hedge losses recorded during the second half of 2013. These losses are temporary and expected to be recovered primarily in 2014.

In 2014, our priorities are consistent with the direction we have taken the Company over the last three years. We will remain focused on efficient operations across all of our businesses, including offsetting inflationary pressures by aggressive cost controls, spreading costs across a broader customer base and sizing our operations to properly reflect market challenges. Several of our specific business objectives are detailed as follows:

- Distribution Operations: Invest necessary capital to enhance and maintain safety and reliability; remain a low-cost leader within the industry; opportunistically expand the system and capitalize on potential customer conversions. We intend to continue investing in our regulatory infrastructure programs in Georgia, Virginia, New Jersey and Tennessee to minimize regulatory lag and the recovery cycle. During 2014 we intend to submit to the Illinois Commission a regulatory infrastructure program in Illinois, to become effective in January 2015. We continue to effectively manage costs and leverage our shared services model across our businesses to largely overcome inflationary effects.
- Retail Operations: Maintain operating margins in Georgia and Illinois while continuing to expand into other profitable retail markets; integrate our warranty businesses and expand our overall market reach through partnership opportunities with our affiliates. We expect the Georgia retail market to remain highly competitive; however, our operating margins are forecasted to remain stable with modest growth from the acquisitions completed in 2013 and expansion into new markets.
- Wholesale Services: Maximize strong storage and transportation rollout value created in 2013; effectively perform on existing asset management agreements and expand customer base; and maintain cost structure in line with market fundamentals. We anticipate low volatility in certain areas of our portfolio; however, volatility is expected to increase in the supply-constrained Northeast corridor. We further anticipate narrow seasonal storage spreads will continue to be challenges in 2014.
- Midstream Operations: Optimize storage portfolio, including expiring contracts, pursue LNG transportation opportunities and lower development expenses.

Additionally, we will maintain our strong balance sheet and liquidity profile, solid investment grade ratings and our commitment to sustainable annual dividend growth. For additional information on our operating segments, see Note 13 to our consolidated financial statements under Part II, Item 8 herein and Item 1, “Business” in the Original Filing.

Results of Operations

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

In millions	2013	2012	2011 (2)
Residential (1)	$2,422	$2,011	$1,065
Commercial	696	656	467
Transportation	487	474	389

Industrial	180	262	289
Other	424	159	95
Total operating revenues (1)	$4,209	$3,562	$2,305

(1) Amount includes prior period adjustments. See Note 15 to our Consolidated Financial Statements under Part II, Item 8 herein for additional information.

(2) Our results of operations for the year ended December 31, 2011 includes 22 days of activity from the subsidiaries acquired from Nicor.

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

We believe operating margin is a better indicator than operating revenues for the contribution resulting from customer growth in our distribution operations segment since the cost of goods sold and revenue tax expenses can vary significantly and are generally billed directly to our customers. We also consider operating margin to be a better indicator in our retail operations, wholesale services and midstream operations segments since it is a direct measure of operating margin before overhead costs. You should not consider operating margin 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, operating margin may not be comparable to similarly titled measures of other companies.

We also believe presenting the non-GAAP measurements of basic and diluted earnings per share - as adjusted, which excludes Nicor merger-related expenses and the additional accrual for the Nicor Gas PBR issue, 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 last three years.

In millions, except per share amounts	2013 (1)	2012 (1)	2011 (1)
Operating revenues	$ 4,209	$3,562	$ 2,305
Cost of goods sold	(2,110)	(1,583)	(1,085)
Revenue tax expense (2)	(110)	(85)	(9)
Operating margin	1,989	1,894	1,211
Operating expenses (3) (4)	(1,471)	(1,369)	(736)
Revenue tax expense (2)	110	85	9
Gain on disposition of assets	11	-	-
Nicor merger expenses (3)	-	(20)	(57)
Operating income	639	590	427
Other income	16	24	7
EBIT	655	614	434
Interest expense, net	(170)	(183)	(134)
Income before income taxes	485	431	300
Income tax expense	(177)	(157)	(121)
Income from continuing operations	308	274	179
Income from discontinued operations, net of tax	5	1	-
Net income	313	275	179
Less net income attributable to the noncontrolling interest	18	15	14
Net income attributable to AGL Resources Inc.	$ 295	$260	$ 165
Per common share data			
Diluted earnings per common share from continuing operations (5) (6)	$ 2.45	$2.20	$ 2.04
Diluted earnings per common share from discontinued operations	0.04	0.01	-
Additional accrual for Nicor Gas PBR issue	-	0.04	-
Transaction costs of Nicor merger (2)	-	0.11	0.80
Diluted earnings per share - as adjusted (5)	$ 2.49	$2.36	$ 2.84

(1) Amount includes prior period adjustments and the sale of Tropical Shipping. See Note 14 and Note 15 to our Consolidated Financial Statements under Part II, Item 8 herein for additional information.

(2) Adjusted for Nicor Gas' revenue tax expenses, which are passed directly through to customers.

(3)

Operating expenses associated with the merger with Nicor are shown separately to better compare year-over-year results and include $20 million ($13 million net of tax) in 2012 and $57 million ($48 million net of tax) in 2011. Additionally, in 2011, transaction costs of the Nicor merger include debt issuance costs and interest expense on pre-funding the cash portion of the purchase consideration of $25 million ($16 million net of taxes).

(4) Total operating expenses in 2013 were unfavorably impacted by increased incentive compensation accruals of $37 million compared to the prior year. These amounts were above targeted levels in 2013.

(5) Excludes net income attributable to the noncontrolling interest.

(6) Gain on disposition of assets increased basic and diluted EPS by $0.04 in 2013.

In 2013 our income from continuing operations increased by $34 million, or 12% compared to 2012.

- The overall increase was primarily the result of increased operating margin at distribution operations and retail operations due to weather that was both colder-than-normal and colder than the same period last year, increased regulatory infrastructure program revenues at Atlanta Gas Light, the acquisition of service contracts and residential and commercial energy customer relationships in our retail operations segment, as well as lower depreciation expense at Nicor Gas.
- The increase was unfavorably impacted by mark-to-market accounting hedge losses in our wholesale services segment during the second half of 2013, offset by higher commercial activity and the $11 million pre-tax gain on the sale of Compass Energy.
- Our midstream operations segment was unfavorable compared to 2012 due to the $8 million loss associated with the termination of the Sawgrass Storage project, as well as lower contracted firm rates at Jefferson Island and higher operating expenses at Golden Triangle, Central Valley and Pivotal LNG resulting from full year operations in 2013 as compared to partial year operations in 2012.
- Favorability year-over-year also was partially offset by higher incentive compensation expenses in most of our businesses as our incentive compensation expense was above targeted levels in 2013 based on improved financial and operational performance compared to significantly below targeted annual levels in 2012 due to below target performance. In addition, our bad debt expense increased at distribution operations and retail operations primarily as a result of colder weather combined with natural gas prices that were higher than in the same period of the prior year.
  - In 2012 we recorded $20 million ($13 million net of tax) of Nicor merger related expenses.
- In 2013 our interest expense decreased by $13 million compared to 2012. This decrease was the result of overall lower interest rates mostly offset by higher average debt outstanding primarily as a result of issuing $500 million of senior notes in place of variable-rate debt.
- In 2013 our income tax expense increased by $20 million or 13% compared to 2012 primarily due to higher consolidated earnings, as previously discussed. Our effective tax rate was 37.9% in 2013 and 2012. Our estimated effective tax rate for 2014 is also 37.9%.

In 2012 our net income from continuing operations increased by $95 million, or 53% compared to 2011.

- The increase was primarily the result of increased operating income at distribution operations and retail operations as a result of the Nicor merger, and increased regulatory infrastructure program revenues at Atlanta Gas Light.
- This increase was partially offset by the effect of warmer-than-normal weather in our distribution operations and retail operations segments, and significantly lower margins at wholesale services resulting from mark-to-market accounting hedge losses.
    - In 2011 we recorded $57 million ($48 million net of tax) of Nicor merger related expenses.
- In 2012 our interest expense increased by $49 million or 37% compared to 2011. This increase was the result of higher average debt outstanding primarily as a result of the additional long-term debt issued to fund the Nicor merger and the long-term debt assumed in the transaction.
- In 2012 our income tax expense increased by $36 million or 30% compared to the same period in 2011 primarily due to higher consolidated earnings. Our effective tax rate was 42.4% in 2011 primarily due to the non-deductible merger transaction expenses in 2011.

The variances for each operating segment are contained within the year-over-year discussion on the following pages.

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 utility 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.

Weather (Heating Degree Days)	Years ended December 31,				2013 vs. 2012	2012 vs. 2011	2013 vs. normal	2012 vs. normal	2011 vs. normal
	Normal (1)	2013	2012	2011	colder (warmer)	colder (warmer)	colder (warmer)	colder (warmer)	colder (warmer)
Year ended December 31,									
Illinois (2)	5,729	6,305	4,863	5,892	30 %	(17)%	10 %	(15)%	3 %
Georgia	2,600	2,689	1,934	2,454	39 %	(21)%	3 %	(26)%	(6)%
Quarter ended December 31,									
Illinois (2)	2,039	2,383	1,890	1,810	26 %	4 %	17 %	(7)%	(11)%
Georgia	1,009	1,049	878	852	19 %	3 %	4 %	(13)%	(16)%

(1) Normal represents the ten-year average from January 1, 2003 through December 31, 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 established by the Illinois Commission in our last rate case, is 2,020 for the fourth quarter and 5,600 for the 12 months from 1998 through 2007.

During 2013 we experienced weather in Illinois that was 10% colder-than-normal and 30% colder than the same period in the prior year. Georgia also experienced 3% colder-than-normal weather, and 39% colder than the same period last year. For our Illinois weather risk associated with Nicor Gas, we implemented a corporate weather hedging program in the second quarter of 2013 that utilizes OTC weather derivatives to reduce the risk of lower operating margins potentially resulting from significantly warmer-than-normal weather. For January through April of 2014, we have purchased a put option that would partially offset lower operating margins resulting from reduced customer usage in the event of warmer-than-normal weather, but would not be exercised in the event of colder-than-normal weather and, therefore, not offset higher margins if Heating Degree Days for the period are at normal or colder-than-normal levels. We will continue to use available methods to mitigate our exposure to weather in Illinois for future periods.

Customers Our customer metrics highlight the average number of customers for which we provide services and are provided in the table below. 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 energy customers at retail operations are primarily located in Georgia and Illinois.

Customers and service contracts (average end-use, in thousands)	Year ended December 31, 2013	2012	2011	2013 vs. 2012 change #	%	2012 vs. 2011 change #	%
Distribution operations customers	4,479	4,459	4,454	20	0.4 %	5	0.1 %
Retail operations							
Energy customers (1)	619	623	578	(4)	(1)%	45	8 %
Service contracts (2)	1,127	684	710	443	65 %	(26)	(4)%
Market share in Georgia	31 %	32 %	33 %		(3)%		(3)%

(1) A portion of the energy customers represents customer equivalents in Ohio, which are computed by the actual delivered volumes divided by the expected average customer usage. The decrease for the year ended 2012 is primarily due to our contract to serve approximately 50,000 customer equivalents that ended on April 1, 2012, which was partially offset by the increase due to the addition of approximately 33,000 residential and commercial customer relationships acquired in Illinois in June 2013.

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

We anticipate overall utility customer growth trends for 2013 to continue in 2014 based on an expectation of continuing improvement in the economy and continuing low natural gas prices. We use a variety of targeted marketing programs to attract new customers and to retain existing customers. These efforts include adding residential customers, multifamily complexes and commercial and industrial customers who use natural gas for purposes other than space heating, as well as evaluating and launching new natural gas related programs, products and services to enhance customer growth, mitigate customer attrition and increase operating revenues. These programs generally emphasize natural gas as the fuel of choice for customers and seek to expand the use of natural gas through a variety of promotional activities. We also target customer conversions to natural gas from other energy sources emphasizing the pricing advantage of natural gas. These programs focus on premises that could be connected to our distribution system at little or no cost to the customer. In cases where conversion cost can be a disincentive, we may employ rebate programs and other assistance to address customer cost issues.

Retail operations' market share in Georgia has decreased slightly primarily as a result of a highly competitive marketing environment, which we expect will continue for the foreseeable future. In 2013 our retail operations segment expanded its energy customers and its service contracts through acquisitions and entering into new markets. We anticipate this expansion will provide growth opportunities in future years.

Volume Our natural gas volume metrics for distribution operations and retail operations, present the effects of weather and 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. Our volume metrics are presented in the following table:

Volumes	Year ended December 31,				
Distribution operations (In Bcf)	2013	2012	2011	2013 vs. 2012 % change	2012 vs. 2011 % change
Firm	720	606	247	19 %	145 %
Interruptible	111	107	105	4 %	2 %
Total	831	713	352	17 %	103 %
Retail operations (In Bcf)					
Georgia firm	38	31	35	23 %	(11)%
Illinois	9	8	-	13 %	-
Other (1)	8	8	10	-	(20)%
Wholesale services					
Daily physical sales (Bcf/day)	5.73	5.54	5.21	3 %	6 %

	As of December 31,		
	2013	2012	2011
Midstream operations			
Working natural gas capacity (in Bcf)	31.8	31.8	13.5
% of firm capacity under subscription by third parties (2)	33 %	46 %	68 %

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

(2) The percentage of capacity under subscription does not include 3.5 Bcf of capacity under contract with Sequent at December 31, 2013, 3 Bcf of capacity under contract with Sequent at December 31, 2012 and 4 Bcf of capacity under contract with Sequent at December 31, 2011.

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

	Operating Margin (1) (2)			Operating Expenses (2) (3)			EBIT (1)		
In millions	2013	2012	2011 (4)	2013	2012	2011 (4)	2013 (5)	2012	2011 (4)
Distribution operations(6)	$ 1,615	$ 1,552	$ 950	$ 1,083	$ 1,044	$ 555	$ 546	$ 517	$ 401
Retail operations (6)	294	247	168	162	136	75	132	111	93
Wholesale services	39	50	57	53	54	52	(3)	(3)	5
Midstream operations	41	46	37	46	38	28	(10)	10	9
Other (7)	8	7	4	25	40	79	(10)	(21)	(74)
Intercompany eliminations	(8)	(8)	(5)	(8)	(8)	(5)	-	-	-
Consolidated (6)	$ 1,989	$ 1,894	$ 1,211	$ 1,361	$ 1,304	$ 784	$ 655	$ 614	$ 434

(1) Operating margin is a non-GAAP measure. A reconciliation of operating revenue and operating margin to operating income and EBIT to earnings before income taxes and net income is contained in "Results of Operations." See Note 13 to our consolidated financial statements under Part II, Item 8 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 $20 million and $57 million in Nicor merger transaction expenses for 2012 and 2011, respectively, and an $8 million accrual in 2012 for the Nicor Gas PBR issue.
(4) The 2011 amounts only include 22 days of Nicor activity from December 10, 2011 through December 31, 2011.
(5) EBIT for 2013 includes $11 million pre-tax gain on sale of Compass Energy in our wholesale services segment and an $8 million pre-tax loss associated with the termination of the Sawgrass Storage project within our midstream operations segment.
(6) Amount includes prior period adjustments. See Note 15 to our consolidated financial statements under Part II, Item 8 herein for additional information.
(7) Our other segment includes our investment in Triton, which was formerly part of our cargo shipping segment that is now classified as discontinued operations. See Note 14 to our consolidated financial statements under Part II, Item 8 set forth herein.

The EBIT of our distribution operations, retail operations and wholesale services segments are seasonal. During the Heating Season, natural gas usage and operating revenues are generally higher because more customers are connected to our distribution systems and natural gas usage is higher in periods of colder weather. Occasionally in the summer, wholesale services operating revenues are impacted due to peak usage by power generators in response to summer energy demands. Seasonality also affects the comparison of certain Consolidated Statements of Financial Position items across quarters, including receivables, unbilled revenue, inventories and short-term debt. However, these items are comparable when reviewing our annual results.

Approximately 67% of these segments' operating revenues and 70% of these segments' EBIT for the year ended December 31, 2013 were generated during the first and fourth quarters of 2013. Our base operating expenses, excluding cost of goods sold, interest expense and certain incentive compensation costs, are incurred relatively equally over any given year. Thus, our operating results can vary significantly from quarter to quarter as a result of seasonality.

Distribution Operations

Our distribution operations segment is the largest component of our business and is subject to regulation and oversight by agencies in each of the seven states we serve. These agencies approve natural gas rates designed to provide us the opportunity to generate revenues to recover the cost of natural gas delivered to our customers and our fixed and variable costs such as depreciation, interest, maintenance and overhead costs, and to earn a reasonable return for our shareholders. With the exception of Atlanta Gas Light, our second largest utility, the earnings of our regulated utilities can be affected by customer consumption patterns that are a function of weather conditions, price levels for natural gas and general economic conditions that may impact our customers' ability to pay for gas consumed. We have various mechanisms, such as weather normalization mechanisms at our utilities and weather derivative instruments that limit our exposure to weather changes within typical ranges in their respective service areas. During 2013, colder-than-normal weather increased our operating margin at our utilities, primarily at Nicor Gas by $12 million compared to expected levels based on 10-year normal weather. During 2012, warmer-than-normal weather decreased our operating margin by $24 million.

In millions	2013	2012
EBIT - prior year (1)	$517	$401
Operating margin		
Increased revenues from regulatory infrastructure programs, primarily at Atlanta Gas Light (1)	4	10
Increased operating margin from Nicor Gas as a result of the Nicor merger in December 2011	-	581
Increased rider revenues primarily as a result of energy efficiency program recoveries at Nicor Gas	19	15
Increased (decreased) operating margin mainly driven by weather, customer usage and customer growth	45	(6)
(Decreased) increased margin from gas storage carrying amounts at Atlanta Gas Light	(5)	2
Increase in operating margin (1)	63	602
Operating expenses		
Increased (decreased) incentive compensation costs that reflect year over year performance (1)	37	(7)
Increased rider expenses primarily as a result of energy efficiency programs at Nicor Gas	19	15
Increased depreciation expense as a result of increased PP&E from infrastructure additions and improvements (1)	11	7
Increased (decreased) bad debt expenses as a result of change in natural gas prices and weather	4	(5)
Increased outside services and other expenses mainly as a result of maintenance programs (1)	1	5
Increased expenses for Nicor Gas as a result of the Nicor merger in December 2011	-	461
Decreased depreciation expense at Nicor Gas due to deprecation study approval effective August 30, 2013	(19)	-
Decreased operation and maintenance expense at Nicor Gas related to the 2012 PBR accrual	(8)	-
(Decreased) increased pension and health benefits expenses primarily related to retiree health care costs and change in actuarial gains and losses	(6)	13
Increase in operating expenses (1)	39	489
Increase in other income primarily from AFUDC equity from STRIDE Projects at Atlanta Gas Light	5	3
EBIT - current year (1)	$546	$517

(1) Amount includes prior period adjustments. See Note 15 to our Consolidated Financial Statements under Part II, Item 8 herein for additional information.

In accordance with an order issued by the Georgia Commission, where AGL Resources makes a business acquisition that reduces the cost allocated or charged to Atlanta Gas Light for shared services, the net savings to Atlanta Gas Light will be shared equally between the firm customers of Atlanta Gas Light and our shareholders for a ten-year period. In December 2013 we filed a Report of Synergy Savings with the Georgia Commission in connection with the Nicor acquisition. If and when approved, the net savings should result in annual rate reductions to the firm customers of Atlanta Gas Light of $5 million. We expect the Georgia Commission to rule on the report in the second quarter of 2014.

Retail Operations

Our retail operations segment, which consists of several businesses that provide energy-related products and services to retail markets, also is weather sensitive and uses a variety of hedging strategies, such as weather derivative instruments and other risk management tools, to partially mitigate potential weather impacts. During 2013, colder-than-normal weather increased operating margin by $9 million. During 2012, warmer-than-normal weather decreased operating margin by $9 million. Additionally, during 2013, our retail operations' EBIT was favorably impacted by $12 million as a result of the acquisition of additional customer and service contracts.

In millions	2013	2012
EBIT - prior year (1)	$111	$93
Operating margin		
Increased margin as a result of the Nicor merger in December 2011	-	76
Increased (decreased) operating margin primarily related to average customer usage in Georgia due to demand and weather, net of weather hedges	17	(10)
Increased margin primarily due to acquisitions in January and June 2013 and expansions into additional retail energy markets	35	-
(Decrease) increase related to change in gas costs and from retail price spreads, partially offset by changes to customer portfolio	(11)	10
Storage inventory write-down (LOCOM) adjustment	3	1
Other	3	2
Increase in operating margin	47	79
Operating expenses		
Increased expenses as a result of the Nicor merger in December 2011	-	64
Increased expenses primarily due to acquisitions in January and June 2013	23	-
Increased (decreased) bad debt expenses related to change in natural gas prices and weather	3	(5)
Other	-	2
Increase in operating expenses (1)	26	61
EBIT - current year (1)	$132	$111

(1) Amount includes prior period adjustments. See Note 15 to our Consolidated Financial Statements under Part II, Item 8 herein for additional information.

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. We principally use physical and financial arrangements to reduce the risks associated with fluctuations in market conditions and changing commodity prices. These economic hedges may not qualify, or are not designated for, hedge accounting treatment. As a result, our reported earnings for wholesale services reflect changes in the fair values of certain derivatives. These values may change significantly from period to period and are reflected as gains or losses within our operating revenues.

In millions	2013	2012
EBIT - prior year	$(3)	$5
Operating margin		
Change in commercial activity in 2013 largely driven by the withdrawal of a portion of the storage inventory economically hedged at the end of 2012, weather and increased cash optimization opportunities in the supply-constrained Northeast corridor	86	5
Change in value of storage hedges as a result of changes in NYMEX natural gas prices	(30)	(23)
Change in value of transportation and forward commodity hedges from price movements related to natural gas transportation positions (1)	(70)	(11)

Change in storage inventory LOCOM adjustment, net of estimated recoveries	3	22
Decrease in operating margin	(11)	(7)
Operating expenses		
Decreased expenses due to sale of Compass Energy in May 2013	(4)	-
Increased payroll, benefits and incentive compensation costs, offset by lower other costs	3	2
(Decrease) increase in operating expenses	(1)	2
Gain on sale of Compass Energy	11	-
(Decrease) increase in other income	(1)	1
EBIT - current year	$(3)	$(3)

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

Change in commercial activity The commercial activity at wholesale services includes recognized storage and transportation values that were generated in prior periods, which reflect the impact of prior period hedge gains and losses as associated physical transactions occur in the period. Additionally, the commercial activity includes operating margin generated and recognized in the current period. For 2013, commercial activity increased significantly due to:

- increased cash optimization opportunities related to certain of our transportation portfolio positions, particularly in the Northeastern U.S.
- 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
- the effects of colder weather

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

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. Storage hedge losses in 2013 are primarily due to the increase in natural gas prices during the fourth quarter of 2013 as compared to storage hedge gains last year resulting from a downward movement in natural gas prices. Losses in our transportation hedge positions in 2013 are the result of widening transportation basis spreads, associated with colder-than-normal weather and higher demand during the second half of 2013 experienced at natural gas receipt and delivery points primarily in the Northeast corridor related to natural gas transportation constraints in the region. These losses are temporary and based on current expectations will be recovered in 2014 through 2016 (with the majority recognized in 2014) via the physical flow of natural gas and utilization of the contracted transportation capacity.

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

In millions	2013	2012	2011
Commercial activity recognized	$129	$43	$38
(Loss) gain on transportation and forward commodity hedges	(73)	(3)	8
(Loss) gain on storage hedges	(16)	14	37
Inventory LOCOM adjustment, net of estimated current period recoveries	(1)	(4)	(26)
Operating margin	$39	$50	$57

For more information on Sequent's expected operating revenues from its storage inventory and transportation and forward commodity hedges in 2014 and discussion of commercial activity, see Item 1 "Business" under the caption Wholesale Services within our Original Filing.

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. Our midstream operations segment also includes an equity investment in Sawgrass Storage, a joint venture between us and a privately held energy exploration and production company. The joint venture decided in December 2013 to terminate the development of the Sawgrass Storage facility. For more information, see Note 10 to our consolidated financial statements under Item 8 herein.

In millions	2013	2012
EBIT - prior year	$10	$9
Operating margin		
Decreased margin from Central Valley Storage as a result of hedge gains in 2012 that did not occur in 2013; increased in 2012 due to the Nicor merger in December 2011	(2)	8
Decreased revenues at Jefferson Island as a result of lower subscription rates	(3)	(4)
Increased revenues primarily at Golden Triangle as a result of Cavern 2 beginning commercial service in 2012 and Cavern 1 working gas capacity project in 2013, as well as revenue due to entry into LNG markets	-	5
(Decrease) increase in operating margin	(5)	9

Operating expenses		
Increased expense from Central Valley Storage as a result of the Nicor merger in December 2011 and the facility beginning commercial service during the second quarter of 2012	4	7
Increased operating and depreciation expenses primarily due to entry into the LNG markets and Cavern 2 at Golden Triangle beginning commercial service in 2012	4	3
Increase in operating expenses	8	10
Impairment loss at Sawgrass Storage	(8)	-
Increase in other income from equity interest in Horizon Pipeline	1	2
Other (expense) income	(7)	2
EBIT - current year	$(10)	$10

Liquidity and Capital Resources

Overview The acquisition of natural gas and pipeline capacity, payment of dividends and funding of working capital needs primarily related to our natural gas inventory are our most significant short-term financing requirements. The liquidity required to fund these short-term needs is primarily provided by our operating activities, and any needs not met, 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. For more information on the seasonality of our short-term borrowings, see “Short-term Debt” later in this section.

The need for long-term capital is driven primarily by capital expenditures and maturities and refinancing of long-term debt. 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 strategy, in May 2013 we issued $500 million in 30-year senior notes with a 4.4% fixed interest rate.

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 $499 million at December 31, 2013.

We believe the amounts available to us under our long-term debt, 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.

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

As of December 31, 2013, our variable-rate debt was $1.4 billion, or 28%, of our total debt, compared to $1.5 billion, or 32%, as of December 31, 2012. The decrease was primarily due to decreased commercial paper borrowings. For more information on our debt, see Note 8 to our consolidated financial statements under Item 8 herein.

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," within our Original Filing for additional information on items that could impact our liquidity and capital resource requirements.

Short-term Debt The following table provides additional information on our short-term debt throughout the year.

In millions	Year-end balance outstanding (1)	Daily average balance outstanding (2)	Minimum balance outstanding (2)	Largest balance outstanding (2)
Commercial paper - AGL Capital	$ 857	$ 777	$ 380	$ 1,064
Commercial paper - Nicor Gas	314	99	-	340
Senior Notes - Current Portion	-	64	-	225
Capital leases - Current Portion	-	-	-	1

Total short-term debt and current portions of long-term debt and capital leases	$ 1,171	$ 940	$ 380	$ 1,630

(1) As of December 31, 2013.

(2) For the twelve months ended December 31, 2013. The minimum and largest balances outstanding for each debt instrument occurred at different times during the year. Consequently, the total balances are not indicative of actual borrowings on any one day during the year.

The largest, minimum and daily average balances borrowed under our commercial paper programs are important when assessing the intra-period 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, margin calls and collateral.

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

The AGL Credit Facility and the Nicor Gas Credit Facility can be drawn upon to meet working capital and other general corporate needs. The interest rates payable on borrowings under these facilities are calculated either at the alternative base rate, plus an applicable margin, or LIBOR, plus an applicable interest margin. The applicable interest margin used in both interest rate calculations will vary according to AGL Capital's and Nicor Gas' current credit ratings.

In November 2013, the lenders for our two credit facilities consented to our request to extend the maturity date of each facility by one year, in accordance with the terms of the respective agreements. The AGL Credit Facility and Nicor Gas Credit Facility maturity dates were extended to November 10, 2017 and December 15, 2017, respectively. The terms, conditions and pricing under the agreements remain unchanged. At December 31, 2013 and 2012, we had no outstanding borrowings under either credit facility.

The timing of natural gas withdrawals is dependent on the weather and natural gas market conditions, both of which impact the price of natural gas. Increasing natural gas commodity prices can have a significant impact on our commercial paper borrowings. Based on current natural gas prices and our expected purchases during the upcoming injection season, we believe that we have sufficient liquidity to cover our working capital needs.

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 December 31, 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. Commercial paper borrowings reduce availability of these credit facilities.

Long-term Debt Our long-term debt matures more than one year from December 31, 2013 and consists of medium-term notes: Series A, Series B, and Series C, which we issued under an indenture dated December 1989; senior notes; first mortgage bonds; and gas facility revenue bonds.

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

	Issuance Date	Amount (in millions)	Term (in years)	Interest rate	
Gas facility revenue bonds (1)		$200	10-20	Floating rate	
Senior notes (2)	May 2013	$500	30	4.4	%
Senior notes - Series A (3) (4)	October 2011	$120	5	1.9	%
Senior notes - Series B (3)	October 2011	$155	7	3.5	%
Senior notes (3)	September 2011	$200	30	5.9	%
Senior notes (3)	September 2011	$300	10	3.5	%
Senior notes (5)	March 2011	$500	30	5.9	%

(1) During the first quarter of 2013, we refinanced the gas facility revenue bonds. We had no cash receipts or payments in connection with the refinancing. See Note 8 to our consolidated financial statements under Item 8 herein for more information.
(2) The net proceeds were used to repay a portion of AGL Capital's commercial paper, including $225 million we borrowed to repay our senior notes that matured on April 15, 2013.
(3) The net proceeds were used to pay a portion of the cash consideration and expenses incurred in connection with the Nicor merger.
(4) In October 2014 the interest rate for these senior notes will change to a floating rate.
(5) The net proceeds were used to repay a portion of AGL Capital's commercial paper, including $300 million we borrowed to repay our senior notes that matured on January 14, 2011. The remaining proceeds were used to pay a portion of the cash consideration and expenses incurred in connection with the Nicor merger.

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 financial performance 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. As of December 31, 2013, if our credit rating had fallen below investment grade, we would have been required to provide collateral of $11 million to continue conducting business with certain customers. The following table summarizes our credit ratings as of January 31, 2014 and reflects upgrades by Moody’s for certain of our ratings compared to 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-1	F1
Senior unsecured	BBB+	A3	BBB+	BBB+	A2	A+
Senior secured	n/a	n/a	n/a	A	Aa3	AA-
Ratings outlook	Stable	Stable	Stable	Stable	Stable	Stable

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, we typically seek to maintain these ratios at levels between 50% and 60%, except for temporary increases related to the timing of acquisition and financing activities. Adjusting for these items, the following table contains our debt-to-capitalization ratios for December 31, which are below the maximum allowed.

	AGL Resources				Nicor Gas			
	2013		2012		2013		2012	
Debt-to-capitalization ratio as calculated from our Consolidated Statement of Financial Position	58	%	59	%	54	%	55	%
Adjustments (1)	(1	)	(1	)	1		-	
Debt-to-capitalization ratio as calculated from our credit facilities	57	%	58	%	55	%	55	%

(1) As defined in credit facilities, includes standby letters of credit, performance/surety bonds and excludes accumulated OCI items related to non-cash pension adjustments, other post-retirement benefits liability adjustments and accounting adjustments for cash flow hedges.

We were in compliance with all of our debt provisions and covenants, both financial and non-financial, as of December 31, 2013 and 2012. For more information on our default provisions, see Note 8 to our consolidated financial statements under Item 8 herein.

Cash Flows

We prepare our Consolidated Statements of Cash Flows using the indirect method. Under this method, we reconcile net income to cash flows from operating activities by adjusting net income for those items that impact net income but may not result in actual cash receipts or payments during the period. These reconciling items include depreciation and amortization, changes in derivative instrument assets and liabilities, deferred income taxes, gains or losses on the sale of assets and changes in the Consolidated Statements of Financial Position for working capital from the beginning to the end of the period. The following table provides a summary of our operating, investing and financing cash flows for the last three years.

In millions	2013	2012	2011
Net cash provided by (used in) (1):			
Operating activities	$971	$1,003	$451
Investing activities	(876)	(786)	(1,339)
Financing activities	(121)	(155)	933
Net (decrease) increase in cash and cash equivalents – continuing operations	(26)	53	31
Net increase in cash and cash equivalents - discontinued operations	-	9	14
Cash and cash equivalents (including held for sale) at beginning of period	131	69	24
Cash and cash equivalents (including held for sale) at end of period	105	131	69
Less cash and cash equivalents held for sale at end of period	24	23	14
Cash and cash equivalents (excluding held for sale) at end of period	$81	$108	$55

(1) Excludes activity for discontinued operations.

Cash Flow from Operating Activities 2013 compared to 2012 Our net cash flow provided by operating activities in 2013 was $971 million, a decrease of $32 million or 3% from 2012. The decrease was primarily related to decreased cash provided by (i) 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 and (ii) deferred income taxes, due to the net change in mark to market activity at wholesale services combined with less cash provided from accelerated tax depreciation in 2013 than in 2012. This decrease in cash provided by operating activities was partially offset by increased cash provided by (i) lower payments for incentive compensation in 2013 as a result of reduced earnings in 2012 as compared to 2011 and (ii) trade payables, other than energy marketing, due to higher gas purchase volumes primarily at distribution operations and retail operations resulting from colder weather in 2013.

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

Cash Flow from Investing Activities The increase in net cash flow used in investing activities was primarily a result of our $122 million acquisition of customer service contracts during the first quarter of 2013 and our $32 million acquisition of residential and commercial energy customer relationships in Illinois during the second quarter of 2013, both in our retail operations segment. This increase was partially offset by decreased spending for PP&E expenditures of $45 million, a net decrease in short-term investments of $7 million and $12 million from the sale of Compass Energy.

Our estimated PP&E expenditures for 2014 and our actual PP&E expenditures incurred in 2013, 2012 and 2011 are within the following categories and are quantified in the following table.

- Distribution business - primarily includes new construction and infrastructure improvements
- Regulatory infrastructure programs - programs that update or expand our distribution systems and liquefied natural gas facilities to improve system reliability and meet operational flexibility and growth. These programs include STRIDE at Atlanta Gas Light, SAVE at Virginia Natural Gas, and an enhanced infrastructure program at Elizabethtown Gas
- Natural gas storage - underground natural gas storage facilities at Golden Triangle, Jefferson Island and Central Valley
- Other - primarily includes information technology and building and leasehold improvements

In millions	2014 (1)	2013	2012	2011 (2)
Distribution business	$503	$421	$371	$159
Regulatory infrastructure programs	163	226	263	192
Natural gas storage	4	6	55	22
Other	99	78	86	54
Total	$769	$731	$775	$427

(1) Estimated PP&E expenditures.

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

Our PP&E expenditures were $730 million for the year ended December 31, 2013, compared to $775 million for the same period in 2012.The decrease of $45 million, or 6%, was primarily due to decreased spending of $49 million on our natural gas storage projects consisting of $35 million at Central Valley and $14 million at Golden Triangle. Additionally, capital expenditures decreased $35 million for strategic projects and $16 million for utility infrastructure enhancement projects at Elizabethtown Gas. These decreases were partially offset by increased expenditures of $54 million for regulatory infrastructure programs at Atlanta Gas Light and $9 million for accelerated infrastructure replacement program projects at Virginia Natural Gas.

Our PP&E expenditures were $775 million for the year ended December 31, 2012, compared to $427 million for the same period in 2011.The increase of $348 million, or 81%, was primarily due to $188 million of PP&E expenditures at Nicor Gas and $31 million of PP&E expenditures at Central Valley, both of which were acquired through our merger with Nicor in December 2011. Additionally, capital expenditures increased $63 million for pipeline replacement projects, $21 million for i-SRP projects and $10 million for i-CGP projects at Atlanta Gas Light, as well as $16 million for accelerated infrastructure replacement program projects at Virginia Natural Gas.

Our estimated expenditures for 2014 include discretionary spending for capital projects principally within the distribution business, regulatory infrastructure programs, natural gas storage and other categories. We continuously evaluate whether or not to proceed with these projects, reviewing them in relation to various factors, including our authorized returns on rate base, other returns on invested capital for projects of a similar nature, capital structure and credit ratings, among others. We will make adjustments to these discretionary expenditures as necessary based upon these factors.

Cash Flow from Financing Activities During 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 our other financing arrangements. 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.

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 with net proceeds of $494 million 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.

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

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

For more information on our financing activities, see short and long-term debt within "Liquidity and Capital Resources."

Noncontrolling Interest We recorded cash distributions for SouthStar's dividend distributions to Piedmont of $17 million in 2013, $14 million in 2012 and $16 million in 2011 in our Consolidated Statements of Cash Flows as financing activities. The primary reason for the increase in the distribution to Piedmont during the current year was increased earnings for 2012 compared to 2011 and a distribution of excess working capital from the joint venture in 2013. Additionally, we received $22.5 million from Piedmont in 2013 to maintain their 15% ownership interest after we contributed our Illinois Energy business to the SouthStar joint venture.

Dividends on Common Stock Our common stock dividend payments were $222 million in 2013, $203 million in 2012 and $148 million in 2011. The increases were generally the result of the annual dividend increase of $0.04 per share for each of the last three years. However, as a result of the Nicor merger, AGL Resources shareholders of record as of the close of business on December 8, 2011 received a pro rata dividend of $0.0989 per share for the stub period, which accrued from November 19, 2011 and totaled $7 million. The dividend payments made in February 2012 were reduced by this stub period dividend. For information about restrictions on our ability to pay dividends on our common stock, see Note 9 to our consolidated financial statements under Item 8 herein.

Shelf Registration In July 2013, we filed a shelf registration statement with the SEC, which expires in 2016. Under this shelf registration statement, debt securities will be issued by AGL Capital and related guarantees will be issued by AGL Resources under an indenture dated as of February 20, 2001, as supplemented and modified, as necessary, among AGL Capital, AGL Resources and The Bank of New York Mellon Trust Company, N.A., as trustee. The indenture provides for the issuance from time to time of debt securities in an unlimited dollar amount and an unlimited number of series, subject to our AGL Credit Facility financial covenant related to total debt to total capitalization.

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

Contractual Obligations and Commitments We have incurred various contractual obligations and financial commitments in the normal course of business that are reasonably likely to have a material effect on liquidity or the availability of requirements for capital resources. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements. These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related revenue-producing activities. Contingent financial commitments represent obligations that become payable only if certain predefined events occur, such as financial guarantees, and include the nature of the guarantee and the maximum potential amount of future payments that could be required of us as the guarantor. The following table illustrates our expected future contractual obligation payments and commitments and contingencies as of December 31, 2013.

In millions	Total	2014	2015	2016	2017	2018	2019 & thereafter
Recorded contractual obligations:							
Long-term debt (1)	$ 3,706	$ -	$ 200	$ 545	$ 22	$ 155	$ 2,784
Short-term debt	1,171	1,171	-	-	-	-	-
Environmental remediation liabilities (2)	447	70	82	80	48	63	104
Pipeline replacement program costs (2)	5	5	-	-	-	-	-
Total	$ 5,329	$ 1,246	$ 282	$ 625	$ 70	$ 218	$ 2,888
Unrecorded contractual obligations and commitments (3) (8):							
Pipeline charges, storage capacity and gas supply (4)	$ 2,298	$ 733	$ 507	$ 299	$ 138	$ 102	$ 519
Interest charges (5)	2,899	185	175	161	147	145	2,086
Operating leases (6)	203	28	27	24	21	17	86
Asset management agreements (7)	19	8	5	4	2	-	-
Standby letters of credit, performance/surety bonds (8)	27	27	-	-	-	-	-
Other	5	1	2	2	-	-	-
Total	$ 5,451	$ 982	$ 716	$ 490	$ 308	$ 264	$ 2,691

(1) Excludes the $82 million step up to fair value of first mortgage bonds, $16 million unamortized debt premium and $9 million interest rate swaps fair value adjustment.

(2) Includes charges recoverable through base rates or rate rider mechanisms.

(3) In accordance with GAAP, these items are not reflected in our Consolidated Statements of Financial Position.

(4) Includes charges recoverable through a natural gas cost recovery mechanism or alternatively billed to Marketers and demand charges associated with Sequent. The gas supply balance includes amounts for Nicor Gas and SouthStar gas commodity purchase commitments of 31 Bcf at floating gas prices calculated using forward natural gas prices as of December 31, 2013, and is valued at $136 million. As we do for other subsidiaries, we provide guarantees to certain gas suppliers for SouthStar in support of payment obligations.

(5) Floating rate interest charges are calculated based on the interest rate as of December 31, 2013 and the maturity date of the underlying debt instrument. As of December 31, 2013, we have $52 million of accrued interest on our Consolidated Statements of Financial Position that will be paid in 2014.

(6) We have certain operating leases with provisions for step rent or escalation payments and certain lease concessions. We account for these leases by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms, in accordance with authoritative guidance related to leases. Our operating leases are primarily for real estate.

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

(8) We provide guarantees to certain municipalities and other agencies and certain gas suppliers of SouthStar in support of payment obligations.

Standby letters of credit and performance/surety bonds. We also have incurred various financial commitments in the normal course of business. Contingent financial commitments represent obligations that become payable only if certain predefined events occur, such as financial guarantees, and the maximum potential amount of future payments that could be required of us as the guarantor. We would expect to fund these contingent financial commitments with operating and financing cash flows.

Pension and other retirement obligations. Generally, our funding policy is to contribute annually an amount that will at least equal the minimum amount required to comply with the Pension Protection Act. We calculate any required pension contributions using the traditional unit credit cost method; however, additional voluntary contributions are periodically made. Contributions are intended to provide not only for benefits attributed to service to date, but also for those expected to be earned in the future. The contributions represent the portion of the other retirement costs which we are responsible for under the terms of our plan and minimum funding required by state regulatory commissions.

The state regulatory commissions in all of our jurisdictions, except Illinois, have phase-ins that defer a portion of the retirement benefit expenses for retirement plans other than pensions for future recovery. We recorded a regulatory asset for these future recoveries of $108 million as of December 31, 2013 and $215 million as of December 31, 2012. In Illinois, all accrued retirement plan expenses are recovered through base rates. See Note 6 to our consolidated financial statements under Item 8 herein for additional information about our pension and other retirement plans.

In 2013, no contributions were required to our qualified pension plans. In 2012, we contributed $40 million to these qualified pension plans. Effective December 31, 2012, we merged the NUI Pension and Nicor Pension plans into the AGL Pension plan. Based on the estimated funded status of the merged AGL Pension plan, we do not expect any required contribution to the plan in 2014. We may, at times, elect to contribute additional amounts to the AGL Pension Plan in accordance with the funding requirements of the Pension Protection Act.

Critical Accounting Policies and Estimates

The preparation of our financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts in our consolidated financial statements and accompanying notes. Those judgments and estimates have a significant effect on our financial statements, primarily due to the need to make estimates about the effects of matters that are inherently uncertain. Actual results could differ from those estimates. We frequently reevaluate our judgments and estimates that are based upon historical experience and various other assumptions that we believe to be reasonable under the circumstances. The following is a summary of our most critical accounting policies, which represent those that may involve a higher degree of uncertainty, judgment and complexity. Our significant accounting policies are described in Note 2 to our consolidated financial statements under Item 8 herein.

Accounting for Rate-Regulated Subsidiaries

We account for the financial effects of regulation in accordance with authoritative guidance related to regulated entities whose rates are designed to recover the costs of providing service. In accordance with this guidance, incurred costs and estimated future expenditures that would otherwise be charged to expense in the current period are capitalized as regulatory assets when it is probable that such costs or expenditures will be recovered in rates in the future. Similarly, we recognize regulatory liabilities when it is probable that regulators will require customer refunds through future rates or when revenue is collected from customers for 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. At December 31, 2013, our regulatory assets were $819 million and regulatory liabilities were $1.7 billion. At December 31, 2012, our regulatory assets were $1.0 billion and regulatory liabilities were $1.6 billion.

We believe our regulatory assets are probable of recovery. Base rates are designed to provide both a recovery of cost and a return on investment during the period rates are in effect. As such, all of our regulatory assets recoverable through base rates are subject to review by the respective state regulatory commission during future rate proceedings. We are not aware of any evidence that these costs will not be recoverable through either rate riders or base rates, and we believe that we will be able to recover such costs consistent with our historical recoveries. In the event that the provisions of authoritative guidance related to regulated operations were no longer applicable, we would recognize a write-off of regulatory assets that would result in a charge to net income and be classified as an extraordinary item. Additionally, while some regulatory liabilities would be written off, others may continue to be recorded as liabilities but not as regulatory liabilities.

Although the natural gas distribution industry is competing with alternative fuels, primarily electricity, our utility operations continue to recover their costs through cost-based rates established by the state regulatory commissions. As a result, we believe that the accounting prescribed under the guidance remains appropriate. It is also our opinion that all regulatory assets are probable of recovery in future rate proceedings, and therefore we have not recorded any regulatory assets that are recoverable but are not yet included in base rates or contemplated in a rate rider. The regulatory liabilities that do not represent revenue collected from customers for expenditures that have not yet been incurred are refunded to ratepayers through a rate rider or base rates. If the regulatory liability is included in base rates, the amount is reflected as a reduction to the rate base in setting rates.

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

Our natural gas distribution operations and certain regulated transmission and storage operations meet the criteria of a cost-based, rate-regulated entity under accounting principles generally accepted in the U.S. Accordingly, the financial results of these operations reflect the effects of the ratemaking and accounting practices and policies of the various regulatory commissions to which we are subject.

As a result, certain costs that would normally be expensed under accounting principles generally accepted in the U.S. are permitted to be capitalized or deferred on the balance sheet because it is probable that they can be recovered through rates. Further, regulation may impact the period in which revenues or expenses are recognized. The amounts to be recovered or recognized are based upon historical experience and our understanding of the regulations.

Discontinuing the application of this method of accounting for regulatory assets and liabilities could significantly increase our operating expenses, as fewer costs would likely be capitalized or deferred on the balance sheet, which could reduce our net income. Assets and liabilities recognized as a result of rate regulation would be written off as extraordinary items in income for the period in which the discontinuation occurred. A write-off of all our regulatory assets and regulatory liabilities at December 31, 2013, would result in 6% and 12% decreases in total assets and total liabilities, respectively. For more information on our regulated assets and liabilities, see Note 3 to our consolidated financial statements under Item 8 herein.

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

Goodwill We do not amortize our goodwill, but test it for impairment at the reporting unit level during the fourth fiscal quarter or more frequently if impairment indicators arise. These indicators include, but are not limited to, a significant change in operating performance, the business climate, legal or regulatory factors, or a planned sale or disposition of a significant portion of the business. A reporting unit is the operating segment, or a business one level below the operating segment (a component), if discrete financial information is prepared and regularly reviewed by management. Components are aggregated if they have similar economic characteristics.

As part of our impairment test, an initial assessment is made by comparing the fair value of a reporting unit with its carrying value, including goodwill. If the fair value is less than the carrying value, an impairment is indicated, and we must perform a second test to quantify the amount of the impairment. In the second test, we calculate the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value of the entire reporting unit determined in step one of the assessment. If the carrying value of the goodwill exceeds the implied fair value of the goodwill, we record an impairment charge. To estimate the fair value of our reporting units, we use two generally accepted valuation approaches, an income approach and a market approach, using assumptions consistent with a market participant’s perspective.

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

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

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

The significant assumptions that drive the estimated fair values of our reporting units are projected cash flows, discount rates, growth rates, weighted average cost of capital (WACC) and market multiples. Due to the subjectivity of these assumptions, we cannot provide assurance that future analyses will not result in impairment as a future impairment depends on market and economic factors affecting fair value. Our annual goodwill impairment analysis in the fourth quarter of 2013 indicated that the estimated fair value of all but one of our reporting units with goodwill was in excess of the carrying value by approximately 20% to almost 500%, and none of the reporting units were at risk of failing step one of the impairment test.

Within our midstream operations segment, the estimated fair value of the storage and fuels reporting unit with $14 million of goodwill, exceeded its carrying value by less than 5% and is at risk of failing the step one test. The discounted cash flow model used in the goodwill impairment test for this reporting unit assumed discrete period revenue growth through fiscal 2021 to reflect the recovery of subscription rates, stabilization of earnings and establishment of a reasonable base year off of which we estimated the terminal value. In the terminal year we assumed a long-term earnings growth rate of 2.5% that we believe is appropriate given the current economic and industry-specific expectations. As of the valuation date, we utilized a WACC of 7.0%, which we believe is appropriate as it reflects the relative risk, the time value of money, and is consistent with the peer group of this reporting unit as well as the discount rate that was utilized in our 2012 annual goodwill impairment test.

The cash flow forecast for the storage and fuels reporting unit assumed earnings growth over the next eight years. Should this growth not occur, this reporting unit will likely fail step one of a goodwill impairment test in a future period. Along with any reductions to our cash flow forecast, changes in other key assumptions used in our 2013 annual impairment analysis may result in the requirement to proceed to step two of the goodwill impairment test in future periods. For more information, see “Acquisitions” in Note 2 to our consolidated financial statements under Item 8 herein.

We will continue to monitor this reporting unit for impairment and note that continued declines in contracted capacity or subscription rates, declines for a sustained period at the current market rates or other changes to the key assumptions and factors used in this analysis may result in future failure of the step 1 goodwill impairment test and may also result in a future impairment of goodwill. If subscription rates and subscribed volumes decline, the estimated future cash flows will decrease from our current estimates. As of December 31, 2013, we estimate that 15% of our future cash flows will be received over the next 10 years, an additional 20% over the following 10 years and 65% in periods thereafter over the remaining useful lives of our storage facilities. The risk of impairment of the underlying long-lived assets is not estimated to be significant because the assets have long remaining useful lives and authoritative accounting guidance requires such assets to be tested for impairment based on the basis of undiscounted cash flows over their remaining useful lives.

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

We determined that there were no long-lived asset impairments in 2013; however, if our storage facilities within midstream operations experience further natural gas price declines or a prolonged slow recovery, future analyses may result in an impairment of long-lived assets.

Derivatives and Hedging Activities

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

The authoritative guidance related to derivatives and hedging requires that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the Consolidated Statements of Financial Position as either an asset or liability measured at its fair value. However, if the derivative transaction qualifies for and is designated as a normal purchase or normal sale, it is exempted from fair value accounting treatment and is, instead, subject to traditional accrual accounting. We utilize market data or assumptions that market participants would use in pricing the derivative asset or liability, including assumptions about risk and the risks inherent in the inputs of the valuation technique.

The authoritative accounting guidance requires that changes in the derivatives' fair value are recognized concurrently in earnings unless specific hedge accounting criteria are met. If the derivatives meet those criteria, the guidance allows derivative gains and losses to offset related results of the hedged item in the income statement in the case of a fair value hedge, or to record the gains and losses in OCI until the hedged transaction occurs in the case of a cash flow hedge. Additionally, the guidance requires that a company formally designate a derivative as a hedge as well as document and assess the effectiveness of derivatives associated with transactions that receive hedge accounting treatment.

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

We use derivative instruments primarily to reduce the impact to our results of operations due to the risk of changes in the price of natural gas. The fair value of natural gas derivative instruments used to manage our exposure to changing natural gas prices reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains or losses on open contracts. For the derivatives utilized in retail operations and wholesale services that are not designated as accounting hedges, changes in fair value are reported as gains or losses in our results of operations in the period of change. Retail operations records derivative gains or losses arising from cash flow hedges in OCI and reclassifies them into earnings in the same period that the underlying hedged item is recognized in earnings.

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

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

We have recorded derivative instrument assets of $119 million at December 31, 2013 and $144 million at December 31, 2012. Additionally, we have recorded derivative liabilities of $80 million at December 31, 2013 and $39 million at December 31, 2012. We recorded losses on our Consolidated Statements of Income of $97 million in 2013 and gains of $10 million in 2012 and $24 million in 2011.

If there is a significant change in the underlying market prices or pricing assumptions we use in pricing our derivative assets or liabilities, we may experience a significant impact on our financial position, results of operations and cash flows. Our derivative and hedging activities are described in further detail in Note 2 and Note 5 to our consolidated financial statements under Item 8 herein and Item 1, “Business” within our Original Filing.

Contingencies

Our accounting policies for contingencies cover a variety of activities that are incurred in the normal course of business and generally relate to contingencies for potentially uncollectible receivables, and legal and environmental exposures. We accrue for these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated. We base our estimates for these liabilities on currently available facts and our estimates of the ultimate outcome or resolution of the liability in the future.

Actual results may differ from estimates, and estimates can be, and often are, revised either negatively or positively depending on actual outcomes or changes in the facts or expectations surrounding each potential exposure. Changes in the estimates related to contingencies could have a negative impact on our consolidated results of operations, cash flows or financial position. Our contingencies are further discussed in Note 11 to our consolidated financial statements under Item 8 herein.

Pension and Other Retirement Plans

Our pension and other retirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates. We annually review the estimates and assumptions underlying our pension and other retirement plan costs and liabilities and update them when appropriate. The critical actuarial assumptions used to develop the required estimates for our pension and other retirement plans include the following key factors:

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

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

The expected long-term rate of return on assets is used to calculate the expected return on plan assets component of our annual pension and other retirement plans costs. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider guidance from our investment advisors in making a final determination of our expected rate of return on assets. To the extent the actual rate of return on assets realized over the course of a year is greater or less than the assumed rate, that year's annual pension or other retirement plan cost is not affected; rather, this gain or loss reduces or increases future pension or other retirement plan costs.

Equity market performance and corporate bond rates have a significant effect on our reported results. For the AGL pension plan, market performance affects our market-related value of plan assets (MRVPA), which is a calculated value and differs from the actual market value of plan assets. The MRVPA recognizes differences between the actual market value and expected market value of our plan assets and is determined by our actuaries using a five-year smoothing weighted average methodology. Gains and losses on plan assets are spread through the MRVPA based on the five-year smoothing weighted average methodology, which affects the expected return on plan assets component of pension expense.

In addition, differences between actuarial assumptions and actual plan experience are deferred and amortized into cost when the accumulated differences exceed 10% of the greater of the projected benefit obligation (PBO) or the MRVPA for the AGL pension plan. The excess, if any, is amortized over the average remaining service period of active employees.

During 2013, we recorded net periodic benefit costs of $57 million (pre-capitalization) related to our defined pension and other retirement benefit plans. We estimate that in 2014, we will record net periodic pension and other retirement benefit costs in the range of $38 million to $42 million (pre-capitalization), a $15 million to $19 million decrease compared to 2013. In determining our estimated expenses for 2014, our actuarial consultant assumed the following expected return on plan assets and discount rates:

	Pension plans	Other retirement plans
Discount rate	5.00 %	4.70 %
Expected return on plan assets	7.75 %	7.75 %

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

Dollars in millions	Percentage-point change in assumption	Increase (decrease) in PBO/ APBO	Increase (decrease) in cost
Expected long-term return on plan assets	+ / - 1 %	$ - / -	$ (9) / 9
Discount rate	+ / - 1 %	$ (154) / 171	$ (13) / 13

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

Income Taxes

The determination of our provision for income taxes requires significant judgment, the use of estimates, and the interpretation and application of complex tax laws. Significant judgment is required in assessing the timing and amounts of deductible and taxable items. We account for income taxes in accordance with authoritative guidance, which requires that deferred tax assets and liabilities be recognized using enacted tax rates for the effect of temporary differences between the book and tax basis of recorded assets and liabilities. The guidance also requires that deferred tax assets be reduced by a valuation allowance if it is more likely than not that some or all of the deferred tax assets will not be realized.

Deferred tax liabilities are estimated based on the expected future tax consequences of items recognized in the financial statements. Additionally, during the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. As a result, we recognize tax liabilities based on estimates of whether additional taxes and interest will be due. After application of the federal statutory tax rate to book income, judgment is required with respect to the timing and deductibility of expense in our income tax returns.

A deferred income tax liability is not recorded on undistributed foreign earnings that are expected, in our judgment, to be indefinitely reinvested offshore. We consider, among other factors, actual cash investments offshore as well as projected cash requirements in making this determination. Changes in our investment or repatriation plans or circumstances could result in a different deferred income tax liability and we would be required to record a deferred tax liability of $31 million if we no longer asserted indefinite reinvestment of undistributed foreign earnings.

For state income tax and other taxes, judgment is also required with respect to the apportionment among the various jurisdictions. A valuation allowance is recorded if we expect that it is more likely than not that our deferred tax assets will not be realized. In addition, we operate within multiple tax jurisdictions and we are subject to audits in these jurisdictions. These audits can involve complex issues, which may require an extended period of time to resolve. We maintain a liability for the estimate of potential income tax exposure and, in our opinion, adequate provisions for income taxes have been made for all years reported.

We had a $22 million valuation allowance on $215 million of deferred tax assets ($146 million of long term and $69 million of current) as of December 31, 2013, reflecting the expectation that most of these assets will be realized. Our gross long-term deferred tax liability totaled $1,760 million at December 31, 2013. See Note 12 to our consolidated financial statements under Item 8 herein for additional information on our taxes.

We are required to determine whether tax benefits claimed or expected to be claimed on our tax return should be recorded in our consolidated financial statements. Under this guidance, we may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement.

Additionally, we recognize accrued interest related to uncertain tax positions in interest expense, and penalties in operating expense in the Consolidated Statements of Income. As of December 31, 2013, we did not have a liability recorded for payment of interest and penalties associated with uncertain tax positions.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of AGL Resources Inc.:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of AGL Resources Inc. and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Management and we previously concluded that the Company maintained effective internal control over financial reporting as of December 31, 2013. However, management has subsequently determined that a material weakness in internal control over financial reporting related to ineffective controls to appropriately apply the accounting guidance related to the recognition of allowed versus incurred costs regarding the accounting for its regulated infrastructure programs which existed as of that date. Accordingly, management's report has been restated and our present opinion on internal control over financial reporting, as presented herein, is different from that expressed in our previous report. In our opinion, the Company did not maintain, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) because a material weakness in internal control over financial reporting related to ineffective controls to appropriately apply the accounting guidance related to the recognition of allowed versus incurred costs regarding the accounting for its regulated infrastructure programs. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis. The material weakness referred to above is described in the accompanying Management's Report on Internal Control Over Financial Reporting. We considered this material weakness in determining the nature, timing, and extent of audit tests applied in our audit of the 2013 consolidated financial statements and our opinion regarding the effectiveness of the Company's internal control over financial reporting does not affect our opinion on those consolidated financial statements. The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in management's report referred to above. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Atlanta, Georgia

February 6, 2014, except with respect to our opinion on the consolidated financial statements insofar as it relates to the effects of discontinued operations described in Note 14, as to which the date is September 2, 2014, and except for the effects of the revision described in Note 15 to the consolidated financial statements and the matter described in the penultimate paragraph of Management's Report on Internal Control Over Financial Reporting, as to which the date is November 7, 2014

Management's Report on Internal Control Over Financial Reporting (as restated)

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision of and with the participation of our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in the Internal Control – Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO Framework") as of December 31, 2013.

A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the Company's annual or interim consolidated financial statements will not be prevented or detected on a timely basis.

We did not maintain effective controls to appropriately apply the accounting guidance related to the recognition of allowed versus incurred costs. Specifically, the Company did not have controls to address the recognition of allowed versus incurred costs, primarily related to an allowed equity return, applied to the accounting for our regulated infrastructure programs and related disclosures that operated at a level of precision to prevent or detect potential material misstatements to the Company's consolidated financial statements. This control deficiency resulted in the misstatement of our regulatory assets and operating revenues and related financial disclosures and resulted in the revision of our consolidated financial statements for the years December 31, 2013, 2012 and 2011 and each of the quarters of March 31, 2014 and June 30, 2014. Additionally, this control deficiency could result in misstatements of the aforementioned accounts and disclosures that would result in a material misstatement of the consolidated financial statements that would not be prevented or detected. Accordingly, our management has concluded that the control deficiency constitutes a material weakness.

In Management's Report on Internal Control Over Financial Reporting included in our original Annual Report on Form 10-K for the year ended December 31, 2013, based on our evaluation under the COSO Framework, our management, including our principal executive officer and principal financial officer, concluded that we maintained effective internal control over financial reporting as of December 31, 2013. Our management has subsequently concluded that the material weakness described above existed as of December 31, 2013. As a result, our management has concluded that we did not maintain effective internal control over financial reporting as of December 31, 2013, based on the criteria in the COSO Framework. Accordingly, management has restated its report on internal control over financial reporting.

The effectiveness of our internal control over financial reporting as of December 31, 2013 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

November 7, 2014

/s/ John W. Somerhalder II	/s/ Andrew W. Evans
John W. Somerhalder II	Andrew W. Evans
Chairman, President and Chief Executive Officer	Executive Vice President and Chief Financial Officer

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

In millions	As of December 31, 2013	2012
Current assets		
Cash and cash equivalents	$81	$108
Short-term investments	49	56
Receivables		
Energy marketing	786	672
Gas	385	362
Unbilled revenues	268	235
Other	83	60
Less allowance for uncollectible accounts	29	28
Total receivables, net	1,493	1,301
Inventories		
Natural gas	637	679
Other	21	20
Total inventories	658	699
Assets held for sale	283	291
Regulatory assets	114	98
Derivative instruments	99	130
Prepaid expenses	63	132
Other	55	21
Total current assets	2,895	2,836
Long-term assets and other deferred debits		
Property, plant and equipment	10,938	10,319
Less accumulated depreciation	2,295	2,114
Property, plant and equipment, net	8,643	8,205
Goodwill	1,827	1,776
Regulatory assets	705	939
Intangible assets	145	71
Long-term investments	113	128
Pension assets	117	33
Derivative instruments	20	14
Other	85	68
Total long-term assets and other deferred debits	11,655	11,234
Total assets	$14,550	$14,070

See Notes to Consolidated Financial Statements.

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

In millions, except share amounts	As of December 31, 2013	2012
Current liabilities		
Short-term debt	$ 1,171	$1,377
Energy marketing trade payables	671	611
Other accounts payable - trade	421	325
Regulatory liabilities	183	161
Customer deposits and credit balances	136	143
Accrued taxes	85	51
Derivative instruments		

Passive foreign investment company considerations

Sasol believes that it should not be classified as a PFIC for US federal income tax purposes for the taxable year ended 30 June 2017. US holders are advised, however, that this conclusion is a factual determination that must be made annually and thus may be subject to change. If Sasol were to be classified as a PFIC, the tax on distributions on its shares or ADSs and on any gains realised upon the disposition of its shares or ADSs may be less favourable than as described herein. Furthermore, dividends paid by a PFIC are not "qualified dividend income" and are not eligible for the reduced rates of taxation for certain dividends. In addition, each US person that is a shareholder of a PFIC, may be required to file an annual report disclosing its ownership of shares in a PFIC and certain other information. US holders should consult their own tax advisors regarding the application of the PFIC rules (including applicable reporting requirements) to their ownership of the shares or ADSs.

US information reporting and backup withholding

Dividend payments made to a holder and proceeds paid from the sale, exchange, or other disposition of shares or ADSs through a US intermediary or other US paying agent may be subject to information reporting to the US Internal Revenue

Service (-IRS). US federal backup withholding generally is imposed on specified payments to persons who fail to furnish required information. Backup withholding will

Table of Contents

not apply to a holder who furnishes a correct taxpayer identification number or certificate of foreign status and makes any other required certification, or who is otherwise exempt from backup withholding. US persons who are required to establish their exempt status generally must provide IRS Form W-9 (Request for Taxpayer Identification Number and Certification) or applicable substitute form. Non-US holders generally will not be subject to US information reporting or backup withholding. However, these holders may be required to provide certification of non-US status (generally on IRS Form W-8BEN, W-8BEN-E or applicable substitute form) in connection with payments received in the United States or through certain US-related financial intermediaries.

Backup withholding is not an additional tax. Amounts withheld as backup withholding may be credited against a holder's US federal income tax liability. A holder may obtain a refund of any excess amounts withheld under the backup withholding rules by timely filing the appropriate claim for refund with the IRS and furnishing any required information.

Additional reporting requirements

Under recently enacted legislation and Treasury regulations, US holders who are individuals may be required to report to the IRS on Form 8938 information relating to their ownership of shares or ADSs, subject to certain exceptions (including an exception for shares or ADSs held in accounts maintained by certain financial institutions). US holders should consult their tax advisors regarding the effect, if any, of

this legislation and these regulations on their obligations to file information reports with respect to the shares or ADSs.

10.F Dividends and paying agents

Not applicable.

10.G Statement by experts

Not applicable.

10.H Documents on display

All reports and other information that we file with the Securities and Exchange Commission (SEC) may be obtained, upon written request, from the Bank of New York Mellon, as Depositary for our ADSs at its Corporate Trust office, located at 101 Barclay Street, New York, New York 10286. These reports and other information can also be inspected without charge and copied at prescribed rates at the public reference facilities maintained by the SEC at 100 F Street, N.E., Washington, D.C. 20549. These reports may also be accessed via the SEC's website (*www.sec.gov*). Also, certain reports and other information concerning us will be available for inspection at the offices of the NYSE. In addition, all the statutory records of the company and its subsidiaries may be viewed at the registered address of the company in South Africa.

10.I Subsidiary information

Not applicable. For a list of our subsidiaries see Exhibit 8.1 to this annual report on Form 20-F.

Table of Contents

ITEM 11. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

As a group, we are exposed to various market risks associated with our underlying assets, liabilities and anticipated transactions. We continuously monitor these exposures and enter into derivative financial instruments to reduce these risks. We do not enter into derivative transactions on a speculative basis. All fair values have been determined using current market pricing models.

The principal market risks (i.e. the risk of losses arising from adverse movements in market rates and prices) to which we are exposed are:

foreign exchange rates applicable on conversion of foreign currency transactions as well as on conversion of assets and liabilities to rand;

commodity prices, mainly crude oil prices; and

interest rates on debt and cash deposits.

Refer to "Item 18 Annual Financial statements Note 39 Financial risk management and financial instruments" for a qualitative and quantitative discussion of the group's exposure to these market risks. Specific recognition and measurement principles of the interest rate swap are contained within the same reference.The following is a breakdown of our debt arrangements and a summary of fixed versus floating interest rate exposures for operations. Liabilities reflect principal payments in each year.

Liabilities notional	2018	2019	2020	2021	2022	Thereafter	Total	Fair value
				(Rand in millions)				
Fixed rate (Rand)	1 150	1 694	25	24	27	434	3 353	3 159
Average interest rate	12,47%	12,32%	13,00%	13,00%	13,00%	0		
Variable rate (Rand)	5 598	7 318	1 180	1 030	733	1 709	17 569	17 541
Average interest rate	7,78%	7,93%	8,17%	7,72%	6,99%	0		
Fixed Rate (US$)	15	9	2	2	1	13 015	13 044	13 396
Average interest rate	4,50%	4,50%	4,50%	4,50%	4,50%	4,47%		
Variable rate (US$)	733	4 447	5 956	3 477	31 734	0	46 347	46 989
Average interest rate	3,35%	3,34%	3,39%	3,52%	3,49%	1,31%		
Fixed rate (Euro)	209	68	49	48	49	99	521	521
Average interest rate	2,36%	2,42%	2,64%	3,01%	3,69%	3,69%		
Variable rate (Euro)	2 542						2 542	2 542
Average interest rate	1,10%							
Variable rate (Other currencies)	777						777	777
Average interest rate								
Total	**11 025**	**13 537**	**7 212**	**4 581**	**32 544**	**15 257**	**84 153**	**84 926**

	2018	2019	2020	2021	2022	Thereafter	Fair value
				(Rand in millions)			
Interest rate swap designated as a hedging instrument*							
Average notional amount	26 078	26 078	25 145	23 875	22 515	18 913	1 070
Average receive rate	1,40%	1,73%	1,96%	2,16%	2,16%	2,57%	
Average pay rate	2,70%	2,70%	2,70%	2,70%	2,70%	2,70%	

Notional at 30 June	26 078	26 078	24 839	23 548	22 166	18 367

86

Table of Contents

	2018	2019	2020	2021	2022	Thereafter	Total Maturity
Foreign Currency Derivatives held for trading*							
USD							
Zero-cost collars	1 543						1 543
Foreign Exchange Contracts	3						3
EUR							
Foreign Exchange Contracts	(392)						(392)
Commodity derivatives held for trading*							
Crude oil							
Crude oil options	1 116						1 116
Crude oil futures	1 602						1 602
Coal price							
Coal swaps	19						19

* For more information relating to contract amounts, weighted average strike prices, notional amounts and weighted average pay rate refer to "Item 18 Annual Financial statements Note 39 Financial risk management and financial instruments".

ITEM 12. DESCRIPTION OF SECURITIES OTHER THAN EQUITY SECURITIES

12.A Debt securities

Not applicable.

12.B Warrants and rights

Not applicable.

12.C Other securities

Not applicable.

12.D American depositary shares

12.D.1 Depositary name and address

Not applicable.

12.D.2 Description of American depositary shares

Not applicable.

12.D.3 Depositary fees and charges

The Bank of New York Mellon serves as the depositary for Sasol's American Depositary Shares (ADSs). Sasol's ADSs, each representing one Sasol ordinary share, are traded on the New York Stock Exchange under the symbol "SSL". The ADSs are evidenced by American Depositary Receipts, or ADRs, issued by The Bank of New York Mellon, as Depositary, under

the Deposit Agreement (dated as of 14 July 1994, as amended and restated as of 6 March 2003), among The Bank of New York Mellon, Sasol Limited and its registered ADR holders. ADR holders are required to pay the following fees to the Depositary:

Service	Fees (USD)
Depositing or substituting the underlying shares	Up to US$5,00 per 100 ADS
Receiving or distributing dividends	Up to US$0,02 per ADS
Selling or exercising rights	Up to US$5,00 per 100 ADS
Withdrawing an underlying security	Up to US$5,00 per 100 ADS

In addition, all non-standard out-of-pocket administration and maintenance expenses, including but not limited to, any and all reasonable legal fees and disbursements incurred by the Depositary (including legal opinions, and any fees and expenses incurred by or waived to third-parties) will be paid by the company. Fees and out-of-pocket expenses for the servicing of non-registered ADR holders and for any special service(s) performed by the Depositary will be paid for by the company.

12.D.4 Depositary payments for 2017

In terms of the Amended and Restated Deposit Letter Agreement dated as of 21 September 2015 (the Letter Agreement), the

Table of Contents

Depositary will pay the company 70% of all dividend fees it collects for as long as the number of ADRs outstanding exceed 50% of the number outstanding on 21 September 2015. These payments will be made to the company within 60 days from the date such fees are collected. During the 2017 financial year, two payments of $547 465,07 and $367 387,17 were received from the Bank of New York Mellon in respect of the 2016 year end final dividend and the 2017 interim dividend respectively.

ITEM 13. DEFAULTS, DIVIDEND ARREARAGES AND DELINQUENCIES

Not applicable.

ITEM 14. MATERIAL MODIFICATIONS TO THE RIGHTS OF SECURITY HOLDERS AND USE OF PROCEEDS

Not applicable.

ITEM 15. CONTROLS AND PROCEDURES

(a) Disclosure controls and procedures

The company's Joint Presidents and Chief Executive Officers and Chief Financial Officer, based on their evaluation of the effectiveness of the group's disclosure controls and procedures (required by paragraph (b) of 17 CFR 240.13a-15) as of the end of the period covered by this annual report on Form 20-F, have concluded that, as of such date, the company's disclosure controls and procedures were effective.

(b) Management's annual report on internal control over financial reporting

Management of Sasol is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934, as amended. Under Section 404 of the Sarbanes-Oxley Act of 2002, management is required to assess the effectiveness of Sasol's internal control over financial reporting as of the end of each financial year and report, based on that assessment, whether the Company's internal control over financial reporting is effective.

Sasol's internal control over financial reporting is a process designed under the supervision of the Joint Presidents and Chief Executive Officers and Chief Financial Officer to provide reasonable assurance as to the reliability of Sasol's financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of our assets; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures are being made only in accordance with authorisations of our management and directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorised acquisition, use or disposition of assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Management assessed the effectiveness of Sasol's internal control over financial reporting as of 30 June 2017. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organisations of the Treadway Commission (COSO) in "Internal Control Integrated Framework (2013)". Based on this assessment, our management has determined that, as of 30 June 2017, Sasol's internal control over financial reporting was effective.

(c) The effectiveness of internal control over financial reporting as of 30 June 2017 was audited by PricewaterhouseCoopers Inc., independent registered public accounting firm, as stated in their report on page F-1 of this Form 20-F.

Table of Contents

(d)

Changes in internal control over financial reporting

There were no changes in our internal control over financial reporting that occurred during the year ended 30 June 2017 that have materially affected, or are likely to materially affect, our internal control over financial reporting as at 30 June 2017.

Item 16.A AUDIT COMMITTEE FINANCIAL EXPERT

Mr. Colin Beggs, an independent member of the audit committee and its chairman since 1 January 2011, was determined by our board to be the audit committee's financial expert within the meaning of the Sarbanes-Oxley Act, in accordance with the Rules of the NYSE and the SEC.

Item 16.B CODE OF ETHICS

Sasol has a code of ethics that applies to all of our directors, officers and employees, including the Joint Presidents and Chief Executive Officers, Chief Financial Officer and the Senior Vice President: Financial Control Services. We undertook a comprehensive review of our code in 2014, and adopted the current code with effect from 1 July 2014. The revised code has been translated into the common languages of all major countries in which we operate, and we conducted an extensive awareness campaign for our employees, service providers and customers. In July 2015, we also adopted a code of ethics for suppliers.

Any amendment or waiver of the code as it relates to our Joint Presidents and Chief Executive Officers or Chief Financial Officer will be posted on our website within five business days following such amendment or waiver. No such amendments or waivers are anticipated.

The code is available on our internet and intranet websites. The website address is http://www.sasol.com/sustainability/ethics. This website is not incorporated by reference in this annual report.

We have been operating an independent ethics reporting telephone line through external advisors since 2002. This confidential and

anonymous ethics hotline provides an impartial facility for all stakeholders to report deviations from ethical behaviour, including fraud and unsafe behaviour or environmental misconduct. Our code of ethics guides our interactions with all government representatives. Our policy prohibits contributions to political parties or government officials since these may be interpreted as an inducement for future beneficial treatment, and as interference in the democratic process.

Item 16.C PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following table sets forth the aggregate audit and audit-related fees, tax fees and all other fees billed by our principal accountants (PricewaterhouseCoopers Inc.) for each of the 2017 and 2016 years:

	Audit fees	Audit-related fees	Tax fees	All other fees	Total
		(Rand in millions)			
2017(1)	**83**	**3**	**3**		89
2016(1)	80	4	1		85

(1) In respect of our audit committee approval process, all non-audit and audit fees paid to PricewaterhouseCoopers Inc. have been pre-approved by the audit committee.

Audit fees consist of fees billed for the annual audit of the company's consolidated financial statements, review of the group's internal controls over financial reporting in accordance with Section 404 of the Sarbanes-Oxley Act and the audit of statutory financial statements of the company's subsidiaries, including fees billed for assurance and related services that are reasonably related to the performance of the audit or reviews of the company's financial statements that are services that only an external auditor can reasonably provide.

Audit-related fees consist of the review of documents filed with regulatory authorities, consultations concerning financial accounting and reporting standards, review of security controls and operational effectiveness of systems,

Table of Contents

due diligence related to acquisitions and employee benefit plan audits.

Tax fees include fees billed for tax compliance services, including assistance in the preparation of original and amended tax returns; tax consultations, such as assistance in connection with tax audits and appeals; tax advice relating to acquisitions, transfer pricing, and requests for rulings or technical advice from tax authorities; and tax planning services and expatriate tax compliance, consultation and planning services.

All other fees consist of fees billed which are not included under audit fees, audit related fees or tax fees.

Audit committee approval policy

In accordance with our audit committee pre-approval policy, all audit and non-audit services performed for us by our independent accountants were approved by the audit committee of our board of directors, which concluded that the provision of such services by the independent accountants was compatible with the maintenance of that firm's independence in the conduct of its auditing functions.

In terms of our policy, non-audit services not exceeding R500 000 that fall into the categories set out in the pre-approval policy, do not require pre-approval by the audit committee, but are pre-approved by the Senior Vice President: Financial Control Services. The audit committee is notified of each such service at its first meeting following the rendering of such service. All non-audit services exceeding R500 000 but not exceeding R2 million are

pre-approved by the Chief Financial Officer. The audit committee is notified on a monthly basis of services approved within this threshold. Fees in respect of non-audit services exceeding R2 million require pre-approval by the audit committee, prior to engagement.

The total aggregate amount of non-audit fees in any one financial year must be less than 20% of the total audit fees for Sasol's annual audit engagement, unless otherwise directed by the audit committee. In addition, services to be provided by the independent accountants that are not within the category of approved services must be approved by the audit committee prior to engagement, regardless of the service being requested and the amount, but subject to the restriction above.

Requests or applications for services that require specific separate approval by the audit committee are required to be submitted to the audit committee by both management and the independent accountants, and must include a detailed description of the services to be provided and a joint statement confirming that the provision of the proposed services does not impair the independence of the independent accountants.

No work was performed by persons other than the principal accountant's employees on the principal accountant's engagement to audit Sasol Limited's financial statements for 2017.

Item 16.D EXEMPTIONS FROM THE LISTING STANDARDS FOR AUDIT COMMITTEES

Not applicable.

Table of Contents

Item 16.E PURCHASES OF EQUITY SECURITIES BY THE ISSUER AND AFFILIATED PURCHASERS

Period	Total number of shares repurchased	Average price paid per share	Shares cancelled under the share repurchase programme	Total number of shares purchased as part of publicly announced programmes	Maximum number of shares that may yet be purchased under the programmes(1)
For the year ended 30 June 2017					
Balance at 30 June 2016	40 309 886		(31 500 000)	8 809 886	56 268 816
2016-07-01 to 2016-07-31					56 591 912
2016-08-01 to 2016-08-31					56 593 482
2016-09-01 to 2016-09-30					56 605 882
2016-10-01 to 2016-10-31					56 607 392
2016-11-01 to 2016-11-30					56 608 562
2016-12-01 to 2016-12-31					56 612 922
2017-01-01 to 2016-01-31					56 612 922
2017-02-01 to 2017-02-29					56 612 922
2017-03-01 to 2017-03-31					56 612 922
2017-04-01 to 2017-04-30					56 612 922
2017-05-01 to 2017-05-31					56 612 922
2017-06-01 to 2017-06-30					56 612 922
2017-07-01 to 2017-07-31					56 612 922
2017-08-01 to 2017-08-28					56 612 922
	40 309 886		**(31 500 000)**	**8 809 886**	

(1) Approval is obtained annually at the annual general meeting for a new maximum number of shares to be repurchased.

a. At our annual general meeting held on 25 November 2016, shareholders granted the authority to the directors to approve the repurchase by the company of its issued securities up to 10% of each of Sasol's ordinary shares and Sasol BEE ordinary shares. The company's issued ordinary shares as at 25 November 2016, was 651 389 516 (4 December 2015 651 389 516) and its issued Sasol BEE ordinary shares as at 25 November 2016, was 2 838 565 (4 December 2015 2 838 565). No shares were repurchased in terms of this authority.

b. The repurchase is limited to a maximum of 10% of the company's securities in the applicable class at the time the authority was granted and no acquisition may be made at a price more than 10% above the weighted average of the market value of the securities for the five business days immediately preceding the date of such acquisition.

c. In terms of the JSE Limited Listings Requirements and the terms of the resolution, the general authority granted to the directors by shareholders on 25 November 2016 to acquire the company's issued securities will not exceed 15 months from the date of the resolution and will be valid only until the company's next annual general meeting, which is scheduled for 17 November 2017.

d. The authority granted by shareholders on 4 December 2015, was replaced by a new authority from shareholders on 25 November 2016 to repurchase Sasol ordinary shares and Sasol BEE ordinary shares. The maximum number of Sasol ordinary shares that could be repurchased between 4 December 2015 and 25 November 2016 amounts to 65 138 951 and the maximum number of Sasol BEE ordinary shares 283 856.

e. No programme was terminated prior to the expiration date. All programme previously approved by shareholders expire at the annual general meeting following the meeting at which such approval was granted.

Item 16.F CHANGE IN REGISTRANT'S CERTIFYING ACCOUNTANT

Not applicable.

Item 16.G CORPORATE GOVERNANCE

Sasol maintains a primary listing of its ordinary shares and Sasol BEE ordinary shares on the Johannesburg Stock Exchange operated by the JSE Limited (JSE) and a listing of American Depositary Shares on the New York Stock Exchange (NYSE). Accordingly, the company is subject to the disclosure, corporate governance and other requirements imposed by applicable South African and United States legislation, the JSE, the United States Securities and Exchange Commission (SEC) and the NYSE. We have implemented controls to provide reasonable assurance of our compliance with all relevant requirements in respect of our listings.

We have compared our corporate governance practices to those for domestic US companies listed on the NYSE and confirm that we comply substantially with such NYSE corporate governance standards and there were no significant differences at 30 June 2017.

Refer to "Integrated Report Our governance framework" as contained in Exhibit 99.9, for further details of our corporate governance practices.

Item 16.H Mine Safety Disclosure

Not applicable.

Item 17. FINANCIAL STATEMENTS

Sasol is furnishing financial statements pursuant to the instructions of Item 18 of Form 20-F.

Table of Contents

Item 18. FINANCIAL STATEMENTS

The following consolidated financial statements, together with the auditors' report of PricewaterhouseCoopers Inc. (PwC) are filed as part of this annual report on Form 20-F:

Index to Consolidated Financial Statements for the years ended 30 June 2017, 2016 and 2015

*

Refer to Item 18 "Annual financial statements" which have been incorporated by reference.

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Sasol Limited

In our opinion, the accompanying consolidated statements of financial position and the related consolidated income statements, statements of comprehensive income, changes in equity and cash flows present fairly, in all material respects, the financial position of Sasol Limited and its subsidiaries at 30 June 2017 and 30 June 2016, and the results of their operations and their cash flows for each of the three years in the period ended 30 June 2017 in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of 30 June 2017, based on criteria established in *Internal Control Integrated Framework* 2013 issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers Inc.

Johannesburg, Republic of South Africa
28 August 2017

Table of Contents

SUPPLEMENTAL OIL AND GAS INFORMATION (unaudited)

In accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Section 932, "Extractive Industries Oil and Gas", and regulations of the US Securities and Exchange Commission (SEC), this section provides supplemental oil and gas information separately about our natural oil and gas exploration and production operations, as managed by Exploration and Production International (E&PI); and about our coal mining operations and the conversion of coal reserves to synthetic oil, as managed by Mining and Sasol Secunda Operations.

NATURAL OIL AND GAS

The supplemental information provided below relates to our natural oil and gas operations, which are managed by Exploration and Production International (E&PI).

Tables 1 through to 3 present historical information pertaining to costs incurred for property acquisitions, exploration and development; capitalised costs; and results of operations. Table 4 presents estimates of proved developed and proved undeveloped reserves (which are not supplemental). Tables 5 and 6 present information on the standardised measure of estimated discounted future net cash flows related to proved reserves and changes therein.

TABLE 1 COSTS INCURRED FOR PROPERTY ACQUISITION, EXPLORATION, AND DEVELOPMENT ACTIVITIES

The table below presents the costs incurred, during the last three years, in natural oil and gas property acquisition, exploration and development activities, whether capitalised or charged to income currently.

	Natural oil and gas (Rand in millions)			
	Mozambique	**North America(1)(2)**	**Other areas(1)**	**Total**
Year ended 30 June 2015				
Acquisition of unproved properties(3)			120,7	120,7
Exploration	550,8		248,9	799,7
Development	636,5	2 923,9	857,7	4 418,1
Total costs incurred	1 187,3	2 923,9	1 227,3	5 338,5
Year ended 30 June 2016				
Acquisition of unproved properties				
Exploration	736,1		238,7	974,8
Development	745,6	7 447,7	391,7	8 585,0
Total costs incurred	1 481,7	7 447,7	630,4	9 559,8
Year ended 30 June 2017				
Acquisition of unproved properties				
Exploration	**40,5**		**372,7**	**413,2**
Development	**1 986,7**	**362,4**	**(43,7)(4)**	**2 305,4**
Total costs incurred	**2 027,2**	**362,4**	**329,0**	**2 718,6**

(1) North America comprises Canada. Other Areas comprises: Gabon, Australia and South Africa.

(2) Development cost in 2016 includes CAD380 million (R4,2 billion), agreed with our partner, Progress Energy, as the first part of the settlement of the remaining funding commitment.

(3) Stated as acquisition of proved properties in 2016.

(4) Relates to the reversal of accruals raised in 2016.

Table of Contents

TABLE 2 CAPITALISED COSTS RELATING TO OIL AND GAS PRODUCING ACTIVITIES

The table below summarises the aggregate amount of property, plant and equipment and intangible assets relating to natural oil and gas exploration and production activities, and the aggregate amount of the related depreciation and amortisation.

	Natural Oil and Gas (Rand in millions)			
	Mozambique	**North America(1)**	**Other areas(1)**	**Total**
Year ended 30 June 2015				
Proved properties	8 135,5	20 171,9	3 836,5	32 143,9
Producing wells and equipment	6 672,5	19 086,0	3 325,0	29 083,5
Non-producing wells and equipment	1 463,0	1 085,9	511,5	3 060,4
Unproved properties	1 882,6	1 278,8	216,3	3 377,7
Capitalised costs	10 018,1	21 450,7	4 052,8	35 521,6
Accumulated depreciation	(2 648,1)	(10 870,8)	(2 875,7)	(16 394,6)
Net book value	7 370,0	10 579,9	1 177,1	19 127,0
Year ended 30 June 2016				
Proved properties	8 992,2	31 030,0	5 099,2	45 121,4
Producing wells and equipment	8 808,2	30 584,2	5 099,2	44 491,6
Non-producing wells and equipment	184	445,8		629,8
Unproved properties	4 466,0		55,9	4 521,9
Capitalised costs	13 458,2	31 030,0	5 155,1	49 643,3
Accumulated depreciation	(3 274,3)	(21 927,3)	(4 545,6)	(29 747,2)
Net book value	10 183,9	9 102,7	609,5	19 896,1
Year ended 30 June 2017				
Proved properties	**8 599,2**	**27 502,1**	**4 251,8**	**40 353,1**
Producing wells and equipment	**8 513,2**	**27 420,2**	**4 250,2**	**40 183,6**
Non-producing wells and equipment	**86,0**	**81,9**	**1,6**	**169,5**
Unproved properties	**6 051,6**		**49,3**	**6 100,9**
Capitalised costs	**14 650,8**	**27 502,1**	**4 301,1**	**46 454,0**
Accumulated depreciation	**(3 832,6)**	**(20 577,9)**	**(4 036,9)**	**(28 447,4)**
Net book value	**10 818,2**	**6 924,2**	**264,2**	**18 006,6**

(1) North America comprises Canada. Other Areas comprises: Gabon, Australia and South Africa

G-2

Table of Contents

TABLE 3 RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES

The results of operations for natural oil and gas producing activities are summarised in the table below.

	Natural oil and gas (Rand in millions)			
	Mozambique	North America(1)	Other areas(1)	Total
Year ended 30 June 2015				
Sales to unaffiliated parties	392,4	695,5	954,9	2 042,8
Transfers to affiliated parties	3 129,2			3 129,2
Total revenues	3 521,6	695,5	954,9	5 172,0
Production costs	(1 102,1)	(161,8)	(493,5)	(1 757,4)
Foreign currency translation (losses)/gains	(402,0)		(9,4)	(411,4)
Exploration expenses	(21,7)		(189,7)	(211,4)
Valuation provision		(1 295,6)	(1 330,7)	(2 626,3)
Farm-down (losses)/gains			(502,9)	(502,9)
Depreciation	(569,3)	(1 604,2)	(259,7)	(2 433,2)
Operating profit / (loss)	1 426,5	(2 366,1)	(1 831,0)	(2 770,6)
Tax	(746,4)		356,8	(389,6)
Results of operations	680,1	(2 366,1)	(1 474,2)	(3 160,2)
Year ended 30 June 2016				
Sales to unaffiliated parties	228,4	466,4	861,4	1 556,2
Transfers to affiliated parties	2 655,2			2 655,2
Total revenues	2 883,6	466,4	861,4	4 211,4
Production costs	(440,8)	(185,8)	(783,1)	(1 409,7)
Foreign currency translation (losses)/gains	(1 053,2)		(2,8)	(1 056,0)
Exploration expenses	(108,8)		(71,1)	(179,9)
Valuation provision		(9 882,1)	(416,8)	(10 298,9)
Farm-down (losses)/gains	347,5		(13,7)	333,8
Depreciation	(630,1)	(1 310,3)	(1 061,5)	(3 001,9)
Operating profit/(loss)	998,2	(10 911,8)	(1 487,6)	(11 401,2)
Tax	589,3		389,1	978,4
Results of operations	1 587,5	(10 911,8)	(1 098,5)	(10 422,8)
Year ended 30 June 2017				
Sales to unaffiliated parties	**224,8**	**559,7**	**835,2**	**1 619,7**
Transfers to affiliated parties	**2 464,7**			**2 464,7**
Total revenues	**2 689,5**	**559,7**	**835,2**	**4 084,4**
Production costs	**(373,3)**	**(48,2)**	**(497,8)**	**(919,3)**
Foreign currency translation (losses)/gains	**345,6**		**(1,6)**	**344,0**
Exploration expenses	**(37,3)**		**(222,5)**	**(259,8)**
Valuation provision			**8,2**	**8,2**
Farm-down (losses)/gains			**(0,9)**	**(0,9)**

Depreciation	**(560,4)**	**(1 260,3)**	**(201,5)**	**(2 022,2)**
Operating profit/(loss)	**2 064,1**	**(748,8)**	**(80,9)**	**1 234,4**
Tax	**(321,1)**		**(126,6)**	**(447,7)**
Results of operations	**1 743,0**	**(748,8)**	**(207,5)**	**786,7**

(1) North America comprises Canada. Other areas comprises: Gabon, Australia and South Africa.

Table of Contents

TABLE 4 PROVED RESERVE QUANTITY INFORMATION

The table below summarises the proved developed and proved undeveloped reserves of natural oil and gas, as at 30 June 2017 and the two previous years, along with volumes produced during the year. Refer to Item 4.D Property, plants and equipment.

Proved reserves of synthetic oil is shown separately on page G-6. As at 30 June 2017, the total proved reserve estimate for natural oil and gas is 216,0 million barrels in oil equivalent terms (6 000 standard cubic feet of natural gas is equivalent to 1 barrel of oil).

The table below also presents the changes in proved reserves of natural oil and gas over the last three years and identifies the reasons for the changes in the estimates.

	Crude oil and condensate(4)				Natural gas(4)			Oil equivalent(1)(4)			
	Mozambique(2)	North America(3)	Rest of Africa(3)	Total	Mozambique(2)	North America(3)(5)	Total	Mozambique	North America(3)(4)	Rest of Africa(3)	Total
	Millions of barrels				Billions of cubic feet			Equivalent, Millions of barrels			
Balance at 30 June 2014	**4,1**	**0,2**	**4,2**	**8,5**	**1 388,4**	**72,5**	**1 460,9**	**235,5**	**12,3**	**4,2**	**252,0**
Revisions	0,0	0,1	(1,3)	(1,2)	(82,8)	33,3	(49,5)	(13,8)	5,6	(1,3)	(9,5)
Improved recovery	0,6	0,2	(0,5)	0,3	174,7	32,8	207,5	29,7	5,7	(0,5)	34,9
Production	(0,3)	(0,2)	(1,3)	(1,8)	(109,2)	(21,8)	(131,0)	(18,5)	(3,8)	(1,3)	(23,6)
Balance at 30 June 2015	4,4	0,3	1,1	5,8	1 371,1	116,8	1 487,9	232,9	19,8	1,1	253,8
Revisions	(0,3)	0,1	0,8	0,6	(42,4)	(0,6)	(43,0)	(7,4)	0,0	0,8	(6,6)
Improved recovery	0,0	0,0	0,4	0,4	(3,8)	27,2	23,4	(0,6)	4,5	0,4	4,3
Production	(0,3)	(0,2)	(1,5)	(2,0)	(114,4)	(20,7)	(135,1)	(19,4)	(3,6)	(1,5)	(24,5)
Balance at 30 June 2016	**3,8**	**0,2**	**0,8**	**4,8**	**1 210,5**	**122,7**	**1 333,2**	**205,5**	**20,7**	**0,8**	**227,0**
Revisions	**0,2**	**0,5**	**2,1**	**2,8**	**88,9**	**21,6**	**110,5**	**15,1**	**4,0**	**2,1**	**21,2**
Improved recovery	**(0,3)**		**0,1**	**(0,2)**	**(43,3)**		**(43,3)**	**(7,5)**		**0,1**	**(7,4)**
Production	**(0,3)**	**(0,1)**	**(1,3)**	**(1,7)**	**(116,4)**	**(21,9)**	**(138,3)**	**(19,7)**	**(3,8)**	**(1.3)**	**(24,8)**
Balance at 30 June 2017	**3,4**	**0,6**	**1,7**	**5,7**	**1 139,7**	**122,4**	**1 262,1**	**193,4**	**20,9**	**1,7**	**216,0**
Proved developed reserves											
At 30 June 2015	1,1	0,3	1,1	2,5	386,8	103,7	490,5	65,5	17,6	1,1	84,2
At 30 June 2016	2,2	0,2	0,8	3,2	738,1	107,9	846,0	125,2	18,2	0,8	144,2
At 30 June 2017	**2,0**	**0,6**	**1,7**	**4,3**	**710,7**	**122,4**	**833,1**	**120,5**	**20,9**	**1,7**	**143,1**
Proved undeveloped reserves											
At 30 June 2015	3,3	0,0		3,3	984,3	13,1	997,4	167,4	2,2		169,6

At 30 June 2016	1,6	0,0	1,6	472,4	14,8	487,2	80,3	2,5	82,8
At 30 June 2017	**1,4**		**1,4**	**429,0**		**429,0**	**72,9**		**72,9**

(1) 6 000 standard cubic feet of natural gas is equivalent to 1 barrel of oil.

(2) Natural oil and gas production in Mozambique in 2015, 2016 and 2017 originated from the single operational Pande-Temane PPA field, which comprises more than 15% of our total proved reserves.

(3) North America comprises Canada, Rest of Africa comprises Gabon.

(4) Volumes presented in this table are after deduction of royalty taken in kind.

(5) Revision of (0,6) billion cubic feet in 2016 was incorrectly stated as 0,6 billion cubic feet in Form 20-F of 2016.

Table of Contents

Preparation of Reserve Estimates

To ensure natural oil and gas reserves are appropriately estimated, are accurately disclosed and are compliant with current Securities and Exchange Commission (SEC) regulations and Financial Accounting Standards Board (FASB) requirements, E&PI has established and maintains estimation guidelines, procedures and standards, which are subject to review by suitably experienced independent external consultants, and a set of internal controls, which are in accordance with the requirements of the Sarbanes Oxley Act of 2002. The internal controls cover, amongst other matters, the segregation of duties between the asset teams which provide the necessary data, the corporate reserves team which prepares the reserves estimates, and the corporate authority which is the E&PI executive committee. The controls also include confirmation that the members of the corporate reserves team are appropriately qualified and experienced and that their compensation arrangements are not materially affected by the reserves.

The process includes a review of all estimated future production rates and future capital and operating costs to ensure that the assumptions, data, methods and procedures are appropriate; a review of the technologies used in the estimation process to determine reliability; and arrangements to validate the economic assumptions and to ensure that only accurate, complete and consistent data are used in the estimation of reserves.

The technical person within E&PI who is primarily responsible for overseeing the preparation of natural oil and gas reserves is the E&PI Manager: Corporate Reserves and Resources. The qualifications of the incumbent include a MA and MSc in Mathematics with 38 years' experience in oil and gas exploration and production activities and 29 years' experience in reserves estimation.

The definitions of categories of natural oil and gas reserves used in this disclosure are

consistent with those set forth in the Regulations:

Proved Reserves of oil and gas Those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract hydrocarbons must be approved and must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Additionally Sasol requires that natural oil and gas reserves will be produced by a "project sanctioned by all internal and external parties".

Existing economic conditions define prices and costs at which economic producibility is to be determined. The price is the average sales price during the 12-month period prior to the ending date of the period covered by the report, determined as an un-weighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements. Future price changes are limited to those provided by contractual arrangements in existence at year-end. At the reporting date, product sales prices were determined by existing contracts for the majority of Sasol's natural oil and gas reserves. Costs comprise development and production expenditure, assessed in real terms, applicable to the reserves class being estimated. Depending upon the status of development proved reserves of oil and gas are subdivided into "Proved Developed Reserves" and "Proved Undeveloped Reserves".

Proved Developed Reserves Those proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods (or in which the cost of the required equipment is relatively minor compared to the cost of a new well) and through

Table of Contents

installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Proved Undeveloped Reserves Those proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required before production can commence.

Definitions of Changes to Proved Reserves

The definitions of the changes to Proved Reserves estimates used in this disclosure are consistent with FASB ASC 932-235-50-5.

TABLE 5 STANDARDISED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED RESERVES

The standardised measures of discounted future net cash flows, relating to natural oil and

gas proved reserves for the last three years, are shown in the table below.

	Natural oil and gas (Rand in million)			
	Mozambique(1)	North America(1)	Rest of Africa(1)	Total
Year ended 30 June 2015				
Future cash inflows	48 356,0	3 908,1	1 006,0	53 270,1
Future production costs	(7 879,1)	(3 122,6)	(1 139,5)	(12 141,2)
Future development costs	(6 825,3)	(1 830,4)	(927,9)	(9 583,6)
Future income taxes	(11 060,1)		(100,4)	(11 160,5)
Undiscounted future net cash flows	22 591,5	(1 044,9)	(1 161,8)	20 384,8
10% annual discount for timing of estimated cash flows	(9 941,5)	882,9	229,2	(8 829,4)
Standardised measure of discounted future net cash flows	12 650,0	(162,0)	(932,6)	11 555,4
Year ended 30 June 2016				
Future cash inflows	31 758,7	3 306,5	507,5	35 572,7
Future production costs	(6 445,2)	(3 140,9)	(967,2)	(10 553,3)
Future development costs	(7 394,8)	(2 436,4)	(889,7)	(10 720,9)
Future income taxes	(6 677,0)	0,0	(50,6)	(6 727,6)
Undiscounted future net cash flows	11 241,7	(2 270,8)	(1 400,0)	7 570,9
10% annual discount for timing of estimated cash flows	(3 797,0)	1 118,1	224,8	(2 454,1)
Standardised measure of discounted future net cash flows	7 444,7	(1 152,7)	(1 175,2)	5 116,8
Year ended 30 June 2017				
Future cash inflows	25 803,2	3 642,5	1 142,7	30 588,4
Future production costs	(6 764,1)	(2 787,4)	(1 236,9)	(10 788,4)
Future development costs	(5 720,9)	(1 613,6)	(595,6)	(7 930,1)
Future income taxes	(5 396,4)		(111,9)	(5 508,3)
Undiscounted future net cash flows	7 921,8	(758,5)	(801,7)	6 361,6
10% annual discount for timing of estimated cash flows	(2 534,0)	620,6	213,2	(1 700,2)
Standardised measure of discounted future net cash flows	5 387,8	(137,9)	(588,5)	4 661,4

(1) North America comprises Canada, Rest of Africa comprises Gabon.

The undiscounted future net cash flows in Canada for our Farrell Creek and Cypress A asset, and in Gabon for our Etame Marin Permit asset, 2015, 2016 and 2017 are negative as a result of future production and development costs, primarily contractually committed costs and asset retirement costs, which are not directly related to future production or dependent upon the continuation of production and will be incurred even in the event of no future production. For both assets these costs are fully responsible for the negative future cash flow.

In Canada, the cost of unused gas transportation capacity is included in production costs. We market the unused capacity on an ad hoc basis and though such marketing has been successful in the past, no future revenue from

Table of Contents

this marketing is included in the calculation of the standardised measure of discounted future net cash flows.

Standardised Measure of Discounted Future Net Cash Flows

The standardised measure of discounted future net cash flows, relating to the proved reserves in the table above, are calculated in accordance with the requirements of FASB ASC Section 932-235. Future cash inflows are computed by applying the prices used in estimating proved reserves to the year-end quantities of those reserves. Future development and production costs are computed by applying the costs used in estimating proved reserves. Future income taxes are computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pre-tax net cash flows relating to the reserves, less the tax basis of the properties involved. The future income tax expenses therefore give effect to the tax deductions, tax credits and allowances relating to the reserves.

Discounted future net cash flows are the result of subtracting future development and production costs and future income taxes from the cash inflows. A discount rate of 10 percent a year is applied to reflect the timing of the future net cash flows relating to the reserves. The information provided here does not represent management's estimate of the expected future cash flows or value of the properties. Estimates of reserves are imprecise and will change over time as new information becomes available. Moreover probable and possible reserves along with other classes of resources, which may become proved reserves in the future, are excluded from the calculations. The valuation prescribed under FASB ASC Section 932 requires assumptions as to the timing and amount of future development and production costs. The calculations are made as of 30 June each year and should not be relied upon as an indication of the companies' future cash flows or value of natural oil and gas reserves.

TABLE 6 CHANGES IN THE STANDARDISED MEASURE OF DISCOUNTED NET CASH FLOWS

The changes in standardised measure of discounted future net cash flows, relating to the Proved Reserves are shown in the table below.

	Natural oil and gas (Rand in millions)			
	Mozambique(1)	**North America(2)**	**Rest of Africa(2)**	**Total**
Present value at 30 June 2014	13 501,1	(400,5)	460,4	13 561,0
Net changes for the year	(851,1)	238,5	(1 393,0)	(2 005,6)
Sales and transfers of oil and gas produced net of production costs	(3 317,7)	(506,8)	(662,0)	(4 486,5)
Development costs incurred	853,8	2 930,0	855,0	4 638,8
Net change due to current reserves estimates from:				
Improved recovery	2 208,6	291,4	(381,5)	2 118,5
Revisions	(1 349,3)	1 118,6	(771,0)	(1 001,7)
Net changes in prices and costs related to future production	(5 216,4)	(440,7)	(1 052,6)	(6 709,7)
Changes in estimated future development costs	(14,9)	(3 114,3)	(102,2)	(3 231,4)
Accretion of discount	1 987,5	(40,1)	100,7	2 048,1
Net change in income tax	769,6		457,2	1 226,8
Net change due to exchange rate	3 227,7	0,4	163,4	3 391,5
Present value at 30 June 2015	12 650,0	(162,0)	(932,6)	11 555,4
Net changes for the year	**(5 205,3)**	**(990,7)**	**(242,6)**	**(6 438,6)**
Sales and transfers of oil and gas produced net of production costs	(2 394,0)	(521,5)	(209,1)	(3 124,6)
Development costs incurred	637,7	2 205,9	570,6	3 414,2
Net change due to current reserves estimates from:				
(Reduced)/improved recovery	(88,3)	182,0	213,5	307,2
Revisions	697,7	333,9	501,8	1 533,4
Net changes in prices and costs related to future production	(11 445,5)	(580,1)	(739,3)	(12 764,9)
Changes in estimated future development costs	(213,1)	(2 565,8)	(354,1)	(3 133,0)
Accretion of discount	1 825,4	(16,2)	(84,3)	1 724,9
Net change in income tax	1 775,2	0,0	43,1	1 818,3
Net change due to exchange rate	3 999,6	(28,9)	(184,8)	3 785,9
Present value at 30 June 2016	7 444,7	(1 152,7)	(1 175,2)	5 116,8
Net changes for the year	(2 056,9)	1 014,8	586,7	(455,4)
Sales and transfers of oil and gas produced net of production costs	(2 141,9)	(434,5)	(375,9)	(2 952,3)

Development costs incurred	267,0	499,9	35,7	802,6
Net change due to current reserves estimates from:				
(Reduced)/improved recovery	(822,0)		15,1	(806,9)
Revisions	1 324,8	434,2	1 204,4	2 963,4
Net changes in prices and costs related to future production	(1 232,1)	413,3	(530,9)	(1 349,7)
Changes in estimated future development costs	289,2	71,5	261,7	622,4
Accretion of discount	1 127,4	(115,3)	(112,9)	899,2
Net change in income tax	522,1		(49,9)	472,2
Net change due to exchange rate	(1 391,4)	145,7	139,4	(1 106,3)
Present value at 30 June 2017	5 387,8	(137,9)	(588,5)	4 661,4

(1) Mozambique values for 2014 have been recalculated in 2015.

(2) North America comprises Canada, Rest of Africa comprises Gabon.

Table of Contents

SYNTHETIC OIL

TABLE 1 COSTS INCURRED FOR PROPERTY ACQUISITION, EXPLORATION, AND DEVELOPMENT ACTIVITIES

The table below provides the costs incurred during the year in synthetic oil property acquisition, exploration and development activities, whether capitalised or charged to income currently.

	Synthetic oil South Africa		
Year ended 30 June	**2017**	**2016**	**2015**
Acquisition of proved properties	0,1	11,8	174,4
Exploration	129,8	154,3	148,0
Development	2 063,8	3 014,4	4 729,7
Total costs incurred	2 193,7	3 180,5	5 052,1

TABLE 2 CAPITALISED COSTS RELATING TO SYNTHETIC OIL ACTIVITIES

The table below summarises the aggregate amount of property, plant and equipment and intangible assets relating to synthetic oil and production activities, and the aggregate amount of the related depreciation and amortisation.

	Synthetic oil South Africa		
Year ended 30 June	**2017**	**2016**	**2015**
Proved properties	91 872,4	85 985,0	78 711,2
Producing wells and equipment	91 872,4	85 985,0	71 191,5
Non-producing wells and equipment			7 519,7
Unproved properties			
Capitalised costs	91 872,4	85 985,0	78 711,2
Accumulated depreciation	(28 936,4)	(26 027,6)	(22 853,3)
Net book value	62 936,0	59 957,4	55 857,9

TABLE 3 RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES

The results of operations for synthetic oil activities are summarised in the table below.

	Synthetic oil South Africa		
Year ended 30 June	**2017**	**2016**	**2015**
Sales to unaffiliated parties			
Transfers to affiliated parties	35 659,7	33 428,4	45 709,4
Total revenues	35 659,7	33 428,4	45 709,4
Production costs	(18 507,5)	(18 557,3)	(14 543,2)
Foreign currency translation gains / (losses)	7,2	8,6	(11,1)
Exploration expenses	(28,0)	(47,0)	(45,0)
Depreciation	(6 088,1)	(5 395,0)	(4 511,8)
Operating profit/(loss)	11 043,3	9 437,7	26 598,3
Tax	(1 967,9)	(2 600,2)	(6 954,4)

Results of operations	9 075,4	6 837,5	19 643,9

TABLE 4 PROVED RESERVE QUANTITY INFORMATION

Proved Reserves

The table below summarises proved developed and proved undeveloped reserves of synthetic oil as at 30 June 2017, for the last three years. As at 30 June 2017, the total proved reserve estimate for synthetic oil is 980,5 million barrels in oil equivalent terms.

	Synthetic oil South Africa		
	2017	**2016**	**2015**
Opening balance	990,9	1 042,5	680,7
Revisions	30,9		413,6
Recovery/ (loss)			
Production	(41,3)	(51,6)	(51,8)
Balance at 30 June	980,5	990,9	1 042,5
Proved developed reserves	980,5	990,9	1 042,5
Proved undeveloped reserves			

Table of Contents

TABLE 5 STANDARDISED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED RESERVES

	Synthetic oil South Africa		
Year ended 30 June	**2017**	**2016**	**2015(1)**
Future cash inflows	670 163,5	630 028,9	906 161,1
Future production costs	(373 987,5)	(341 767,1)	(346 619,9)
Future development costs	(199 417,2)	(183 888,3)	(181 021,4)
Future income taxes	(38 109,1)	(36 878,3)	(114 069,6)
Undiscounted future net cash flows	58 649,7	67 495,2	264 450,3
10% annual discount for timing of estimated cash flows	(40 504,8)	(43 046,6)	(160 169,1)
Standardised measure of discounted future net cash flows	18 144,9	24 448,6	104 281,2

(1) Standardised measure of discounted future net cash flows at 30 June 2015 has been restated to correct the allocation of future development costs. In 2015, the useful life of Secunda Synfuels Operations was extended to 2050, which exceeded the quantities of the proved coal reserves. The future development costs are now allocated in line with proved coal reserves and not on total synthetic oil production as used previously.

The standardised measure of discounted future net cash flows, relating to the proved reserves in the table above, are calculated in accordance with the requirements of FASB ASC Section 932-235.

TABLE 6 CHANGES IN THE STANDARDISED MEASURE OF DISCOUNTED NET CASH FLOWS

	Synthetic oil South Africa		
	2017	**2016**	**2015(1)**
Present value opening balance	24 448,7	104 281,2	162 843,1
Net changes for the year	(6 303,9)	(79 832,5)	(58 562,1)
Sales and transfers of oil and gas produced net of production costs	(17 152,2)	(14 871,2)	(31 166,1)
Development costs incurred	9 339,9	9 367,1	11 369,9
Net change due to current reserves estimates from:			
Improved recovery			
Commercial arrangements			
Revisions	1 695,3	3 527,6	30 491,1
Net changes in prices and costs related to future production	21 021,7	(173 986,8)	(123 966,6)
Changes in estimated future development costs	(11 616,0)	(8 348,0)	(20 968,8)
Accretion of discount	2 195,5	9 441,1	14 599,3
Net change in income tax	2 355,0	35 442,4	28 759,1
Net change due to exchange rate	(14 143,1)	59 595,3	32 320,0
Present value at 30 June	18 144,8	24 448,7	104 281,0

(1) Standardised measure of discounted future net cash flows at 30 June 2015 has been restated to correct the allocation of future development costs. In 2015, the useful life of Secunda Synfuels Operations was extended to 2050, which exceeded the quantities of the proved coal reserves. The future development costs are now allocated in line with proved coal reserves and not on total synthetic oil production as used previously.

Standardised Measure of Discounted Future Net Cash Flows

The standardised measure of discounted future net cash flows, relating to the proved reserves in the table above, are calculated in accordance with the requirements of FASB ASC Section 932-235. Future cash inflows are computed by applying the prices used in estimating proved reserves to the year-end quantities of those reserves. Future development and production costs are computed by applying the costs used in estimating proved reserves. Future income taxes are computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pre-tax net cash flows relating to the reserves, less the tax basis of the properties involved. The future income tax expenses therefore give effect to the tax deductions, tax credits and allowances relating to the reserves.

Table of Contents

Discounted future net cash flows are the result of subtracting future development and production costs and future income taxes from the cash inflows. A discount rate of 10 percent a year is applied to reflect the timing of the future net cash flows relating to the reserves. The information provided here does not represent management's estimate of the expected future cash flows or value of the properties. Estimates of reserves are imprecise and will change over time as new information becomes available. Moreover probable and possible reserves along with other classes of resources, which may become proved reserves in the future, are excluded from the calculations. The valuation prescribed under FASB ASC Section 932 requires assumptions as to the timing and amount of future development and production costs. The calculations are made as of 30 June each year and should not be relied upon as an indication of the companies' future cash flows or value of synthetic oil reserves.

Table of Contents

ITEM 19. EXHIBITS

1.1	Memorandum of incorporation of Sasol Limited
2.1	The amount of long-term debt securities issued by Sasol Limited and its subsidiaries authorised under any given instrument does not exceed 10% of the total assets of Sasol Limited and its subsidiaries on a consolidated basis. Sasol Limited hereby agrees to furnish to the SEC a copy of any such instrument upon its request.
4.1	Management Share Incentive Scheme**
4.2	The Deed of Trust for the Sasol Inzalo Management Trust*
4.3	The Deed of Trust for the Sasol Inzalo Employee Scheme*
8.1	List of subsidiaries
12.1	Certification of Bongani Nqwababa and Stephen Russell Cornell, Joint Presidents and Chief Executive Officers of Sasol Limited pursuant of Section 302 of the Sarbanes-Oxley Act of 2002.
12.2	Certification of Paul Victor, Chief Financial Officer of Sasol Limited pursuant of Section 302 of the Sarbanes-Oxley Act of 2002.
13.1	Certification of Bongani Nqwababa and Stephen Russell Cornell, Joint Presidents and Chief Executive Officers of Sasol Limited and Paul Victor, Chief Financial Officer of Sasol Limited pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
13.2	Certification of Bongani Nqwababa and Stephen Russell Cornell, Joint Presidents and Chief Executive Officers of Sasol Limited and Paul Victor, Chief Financial Officer of Sasol Limited pursuant to Rule 13a-15(f) under the Securities Exchange Act of 1934, as adopted pursuant to Section 404 of the Sarbanes- Oxley Act of 2002.
15.2	Consent of independent registered public accounting firm PwC
99.1	Sasol Limited Consolidated Annual Financial Statements
99.2	Sasol Limited Remuneration Report
99.3	CFO Report
99.4	Our Operating Model Structure
99.5	Integrated Report Our strategy
99.6	Integrated Report Our integrated value chain
99.7	Integrated Report Operational reviews
99.8	Information about our board of directors and senior management
99.9	Integrated Report Our governance framework
99.9.1	Sasol Limited Board Charter
99.9.2	Terms of reference Audit Committee and Remuneration Committee

*
Incorporated by reference to our annual report on Form 20-F filed on 7 October 2008.

**
Incorporated by reference to our registration statement on Form 20-F filed on 6 March 2003.

M-2