ENERGEN CORP
Form 10-K
March 03, 2014

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

FORM 10-K

(X) ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE YEAR ENDED DECEMBER 31, 2013

( ) TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE TRANSITION PERIOD FROM ___ TO ___

Commission File Number	Registrant	State of Incorporation	IRS Employer Identification Number
1-7810	Energen Corporation	Alabama	63-0757759
2-38960	Alabama Gas Corporation	Alabama	63-0022000

605 Richard Arrington Jr. Boulevard North, Birmingham, Alabama 35203-2707
Telephone Number (205) 326-2700
http://www.energen.com

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Exchange on Which Registered
Energen Corporation Common Stock, $0.01 par value	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act: NONE

Indicate by check mark if the registrants are a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES (X) NO ( )

Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
YES ( ) NO (X)

Indicate by a check mark whether registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities and Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports) and (2) have been subject to such filing requirements for the past 90 days. YES (X) NO ( )

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Energen Corporation YES (X) NO ( )
Alabama Gas Corporation YES (X) NO ( )

Indicate by a check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ( )

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.
Energen Corporation Large accelerated filer (X) Accelerated filer ( ) Non-accelerated filer ( ) Smaller reporting company ( )
Alabama Gas Corporation Large accelerated filer ( ) Accelerated filer ( ) Non-accelerated filer (X) Smaller reporting company ( )

Indicate by check mark whether the registrants are a shell company (as defined in Rule 12b-2 of the Exchange Act).
YES ( ) NO (X)

Aggregate market value of the voting stock held by non-affiliates of the registrants as of June 30, 2013:

Energen Corporation	$3,809,442,960

Indicate number of shares outstanding of each of the registrant's classes of common stock as of February 14, 2014:

Energen Corporation	72,713,965 shares
Alabama Gas Corporation	1,972,052 shares

Alabama Gas Corporation meets the conditions set forth in General Instruction I(1) (a) and (b) of Form 10-K and is therefore filing this form with the reduced disclosure format pursuant to General Instruction I(2).

DOCUMENTS INCORPORATED BY REFERENCE
Energen Corporation Proxy Statement to be filed on or about March 21, 2014 (Part III, Item 10-14)

INDUSTRY GLOSSARY

For a more complete definition of certain terms defined below, as well as other terms and concepts applicable to successful efforts accounting, please refer to Rule 4-10(a) of Regulation S-X, promulgated pursuant to the Securities Act of 1933 and the Securities Exchange Act of 1934, each as amended.

Basis	The difference between the futures price for a commodity and the corresponding cash spot price. This commonly is related to factors such as product quality, location and contract pricing.
Basin-Specific	A type of derivative contract whereby the contract's settlement price is based on specific geographic basin indices.
Behind Pipe Reserves	Oil or gas reserves located above or below the currently producing zone(s) that cannot be extracted until a recompletion or pay-add occurs.
Cash Flow Hedge	The designation of a derivative instrument to reduce exposure to variability in cash flows from the forecasted sale of oil, gas or natural gas liquids production whereby the gains (losses) on the derivative transaction are anticipated to offset the losses (gains) on the forecasted sale.
Collar	A financial arrangement that effectively establishes a price range between a floor and a ceiling for the underlying commodity. The purchaser bears the risk of fluctuation between the minimum (or floor) price and the maximum (or ceiling) price.
Development Costs	Costs necessary to gain access to, prepare and equip development wells in areas of proved reserves.
Development Well	A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.
Downspacing	An increase in the number of available drilling locations as a result of a regulatory commission order.
Dry Well	An exploratory or a development well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.
Exploration Expenses	Costs primarily associated with drilling unsuccessful exploratory wells in undeveloped properties, exploratory geological and geophysical activities, and costs of impaired and expired leaseholds.
Exploratory Well	A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir.
Futures Contract	An exchange-traded legal contract to buy or sell a standard quantity and quality of a commodity at a specified future date and price. Such contracts offer liquidity and minimal credit risk exposure but lack the flexibility of swap contracts.

Hedging	The use of derivative commodity instruments such as futures, swaps, options and collars to help reduce financial exposure to commodity price volatility.
Gross Revenues	Revenues reported after deduction of royalty interest payments.
Gross Well or Acre	A well or acre in which a working interest is owned.
Liquified Natural Gas (LNG)	Natural gas that is liquified by reducing the temperature to negative 260 degrees Fahrenheit. LNG typically is used to supplement traditional natural gas supplies during periods of peak demand.
Long-Lived Reserves	Reserves generally considered to have a productive life of approximately 10 years or more, as measured by the reserves-to-production ratio.
Natural Gas Liquids (NGL)	Liquid hydrocarbons that are extracted and separated from the natural gas stream. NGL products include ethane, propane, butane, natural gasoline and other hydrocarbons.
Net Well or Acre	A net well or acre is deemed to exist when the sum of fractional ownership working interests in gross wells or acres equals one.
Odorization	The adding of odorant to natural gas which is a characteristic odor so that leaks can be readily detected by smell.
Operational Enhancement	Any action undertaken to improve production efficiency of oil and gas wells and/or reduce well costs.
Operator	The company responsible for exploration, development and production activities for a specific project.
Pay-Add	An operation within a currently producing wellbore that attempts to access and complete an additional pay zone(s) while maintaining production from the existing completed zone(s).
Pay Zone	The formation from which oil and gas is produced.

Production (Lifting) Costs	Costs incurred to operate and maintain wells.
Productive Well	An exploratory or a development well that is not a dry well.
Proved Developed Reserves	The portion of proved reserves which can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved Reserves	Estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.
Proved Undeveloped Reserves (PUD)	The portion of proved reserves which can be expected to be recovered from new wells on undrilled proved acreage or from existing wells where a relatively major expenditure is required for completion.
Recompletion	An operation within an existing wellbore whereby a completion in one pay zone is abandoned in order to attempt a completion in a different pay zone.
Reserves-to-Production Ratio	Ratio expressing years of supply determined by dividing the remaining recoverable reserves at year end by actual annual production volumes. The reserve-to-production ratio is a statistical indicator with certain limitations, including predictive value. The ratio varies over time as changes occur in production levels and remaining recoverable reserves.
Secondary Recovery	The process of injecting water, gas, etc., into a formation in order to produce additional oil otherwise unobtainable by initial recovery efforts.
Service Well	A well employed for the introduction into an underground stratum of water, gas or other fluid under pressure or disposal of salt water produced with oil or other waste.
Sidetrack Well	A new section of wellbore drilled from an existing well.
Swap	A contractual arrangement in which two parties, called counterparties, effectively agree to exchange or “swap” variable and fixed rate payment streams based on a specified commodity volume. The contracts allow for flexible terms such as specific quantities, settlement dates and location but also expose the parties to counterparty credit risk.
Transportation	Moving gas through pipelines on a contract basis for others.
Throughput	Total volumes of natural gas sold or transported by the gas utility.
Working Interest	Ownership interest in the oil and gas properties that is burdened with the cost of development and operation of the property.
Workover	A major remedial operation on a completed well to restore, maintain, or improve the well’s production such as deepening the well or plugging back to produce from a shallow formation.
-e	Following a unit of measure denotes that the gas components have been converted to barrels of oil equivalents at a rate of 1 barrel per 6 thousand cubic feet.

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This Form 10-K is filed on behalf of Energen Corporation (Energen or the Company) and Alabama Gas Corporation (Alagasco).

Forward-Looking Statements: The disclosure and analysis in this 2013 Annual Report on Form 10-K contains forward-looking statements that express management's expectations of future plans, objectives and performance of the Company and its subsidiaries. Such statements constitute forward-looking statements within the meaning of Section 27A of the Securities Act, as amended, and Section 21E of the Exchange Act, as amended, and are noted in the Company's disclosure as permitted by the Private Securities Litigation Reform Act of 1995. Forward-looking statements often address the Company's future business and financial performance and financial condition, and often contain words such as "expect", "anticipate", "intend", "plan", "believe", "seek", "see", "project", "will", "estimate", "may", a of similar meaning.

All statements based on future expectations rather than on historical facts are forward-looking statements that are dependent on certain events, risks and uncertainties (many of which are beyond our control) that could cause actual results to differ materially from those anticipated. Some of these include, but are not limited to, economic and competitive conditions, production levels, reserve levels, energy markets, supply and demand for and the price of energy commodities including oil, gas and natural gas liquids, fluctuations in the weather, drilling risks, costs associated with compliance with environmental and regulatory obligations, inflation rates, legislative and regulatory changes, financial market conditions, the Company's ability to access the capital markets, acts of nature, sabotage, terrorism (including cyber-attacks) and other similar acts that disrupt operations or cause damage greater than covered by insurance, future business decisions, utility customer growth and retention and usage per customer, litigation results and other factors and uncertainties discussed elsewhere in this 10-K and in the Company's other public filings and press releases, all of which are difficult to predict. While it is not possible to predict or identify all the factors that could cause the Company's actual results to differ materially from expected or historical results, the Company has identified certain risk factors which may affect the Company's future business and financial performance.

See Item 1A, Risk Factors, for a discussion of risk factors that may affect the Company and cause material variances from forward-looking statement expectations. The Item 1A, Risk Factors, discussion is incorporated by reference into this forward-looking statement disclosure.

Except as otherwise disclosed, the forward-looking statements do not reflect the impact of possible or pending acquisitions, investments, divestitures or restructurings. The absence of errors in input data, calculations and formulas used in estimates, assumptions and forecasts cannot be guaranteed. Neither the Company nor Alagasco undertakes any obligation to correct or update any forward-looking statements whether as a result of new information, future events or otherwise.

PART I

ITEM 1. BUSINESS

General

Energen Corporation is an oil and gas exploration and production company complemented by its legacy natural gas distribution business. Headquartered in Birmingham, Alabama, the Company is engaged in the development and exploration of oil, natural gas and natural gas liquids in the continental United States and in the purchase, distribution and sale of natural gas in central and north Alabama. Its two principal subsidiaries are Energen Resources Corporation and Alabama Gas Corporation (Alagasco).

Alagasco was formed in 1948 by the merger of Alabama Gas Company into Birmingham Gas Company, the predecessors of which had been in existence since the mid-1800s. Alagasco became publicly traded in 1953. Energen Resources was formed in 1971 as a subsidiary of Alagasco. Energen was incorporated in 1978 in preparation for the 1979 corporate reorganization in which Alagasco and Energen Resources became subsidiaries of Energen.

The Company maintains a Web site with the address www.energen.com. The Company does not include the information contained on its Web site as part of this report nor is the information incorporated by reference into this report. The Company makes available free of charge through its Web site the annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to these reports. Also, these reports are available in print upon shareholder request. These reports are available as soon as reasonably practicable after being electronically filed with or furnished to the Securities and Exchange Commission. The Company's Web site also includes its Business Conduct Guidelines, Corporate Governance Guidelines, Audit Committee Charter, Officers' Review Committee Charter and Governance and Nominations Committee Charter, each of which is available in print upon shareholder request.

Financial Information About Industry Segments

The information required by this item is provided in Note 20, Industry Segment Information, in the Notes to Financial Statements.

Narrative Description of Business

• Oil and Gas Operations

General: Energen's oil and gas operations focus on increasing production and adding proved reserves through the development of oil and gas properties. In addition, Energen Resources explores for and develops new reservoirs, primarily in areas in which it has an operating presence. All oil, gas and natural gas liquids production is sold to third parties. Energen Resources also provides operating services in the Permian and San Juan basins for its joint interest and third parties. These services include overall project management and day-to-day decision-making relative to project operations.

At the end of 2013, Energen Resources' proved oil and gas reserves totaled 347.8 million barrels of oil equivalent (MMBOE). Substantially all of these reserves are located in the Permian Basin in west Texas and the San Juan Basin in New Mexico and Colorado. Approximately 75 percent of Energen Resources' year-end reserves are proved developed reserves. Energen Resources' reserves are long-lived, with a year-end reserves-to-production ratio of 15 years. Oil, natural gas and natural gas liquids represent approximately 47 percent, 35 percent and 18 percent, respectively, of Energen Resources' proved reserves.

In October 2013, Energen Resources completed the sale of its Black Warrior Basin coalbed methane properties in Alabama for $160 million (subject to closing adjustments). The Company recorded a pre-tax gain on the sale of approximately $35 million in the fourth quarter of 2013 which is reflected in gain on disposal of discontinued operations in the year ended December 31, 2013. At December 31, 2012, proved reserves associated with Energen's Black Warrior Basin properties totaled 97 Bcf of natural gas.

In January 2014, Energen Resources signed a purchase and sale agreement on its North Louisiana/East Texas natural gas and oil properties for $31.5 million (subject to closing adjustments). The Company expects to complete the sale in the first quarter of 2014 and will use the proceeds to repay short-term obligations. During the third quarter of 2013, Energen Resources classified these natural gas and oil properties as held-for-sale and reflected the associated operating results in discontinued operations. Energen Resources recognized a non-cash impairment writedown on these properties in the third and fourth quarters of $24.6 million pre-tax and $5.2 million pre-tax, respectively, to adjust the carrying amount of these properties to their fair value based on an estimate of the selling price of the properties. The non-cash impairment writedowns are reflected in gain on disposal of discontinued operations in the year ended December 31, 2013. At December 31, 2013, proved reserves associated with Energen's North Louisiana/East Texas properties totaled 23 Bcf of natural gas and 91 MBbl of oil.

Growth Strategy: Energen operates under a strategy to grow the oil and gas operations of Energen Resources largely through the development of proved and unproved reserves and through the exploration in and around the basins in which it operates. Energen Resources focuses on increasing production and reserves through development well drilling, exploration, behind-pipe recompletions, pay-adds, workovers, secondary recovery, and operational enhancements. Energen Resources prefers to operate its properties in order to better control the nature and pace of drilling and development activities. Energen Resources operated approximately 95 percent of its proved reserves at December 31, 2013.

Since the end of fiscal year 1995, Energen Resources has invested approximately $1.9 billion to acquire proved and unproved reserves, $4.3 billion in related development and $1.7 billion in exploration. Energen Resources' capital spending plans for 2014 target a total investment of approximately $1.05 billion, the bulk of which will focus on drilling and related development activities on its existing properties, with approximately 99 percent targeting the liquids-rich Permian Basin. The Company may choose to allocate additional capital during the year for property acquisitions and/or increased drilling and development activities.

Energen Resources' development activities can result in the addition of new proved reserves and can serve to reclassify proved undeveloped reserves to proved developed reserves. Proved reserve disclosures are provided annually, although changes to reserve classifications occur throughout the year. Accordingly, additions of new reserves from development activities can occur throughout the year and may result from numerous factors including, but not limited to, regulatory approvals for drilling unit downspacing that increase the number of available drilling locations; changes in the economic or operating environments that allow previously uneconomic locations to be added; technological advances that make reserve locations available for development; successful development of existing proved undeveloped reserve locations that reclassify adjacent probable locations to proved undeveloped reserve locations; increased knowledge of field geology and engineering parameters relative to oil and gas reservoirs; and changes in management's intent to develop certain opportunities.

During the three years ended December 31, 2013, the Company's development and exploratory efforts have added 139 MMBOE of proved reserves from the drilling of 1,308 gross development, exploratory and service wells (including 11 sidetrack wells) and 289 well recompletions and pay-adds. In 2013, Energen Resources' successful development and exploratory wells and other activities added approximately 37 MMBOE of proved reserves; the Company drilled 347 gross development, exploratory and service wells (including no sidetrack wells), performed some 87 well recompletions and pay-adds, and conducted other operational enhancements. Energen Resources' production from continuing operations totaled 23.3 MMBOE in 2013 and in 2014 is estimated to range from 24.4 MMBOE to 25.4 MMBOE, with a midpoint of 24.9 MMBOE, including approximately 22.1 MMBOE of estimated production from proved reserves owned at December 31, 2013.

Drilling Activity: The following table sets forth the total number of net productive and dry exploratory and development wells drilled:

Years ended December 31,	2013	2012	2011
Development:			
Productive	169.5	239.9	370.3
Dry	—	—	3.3
Total	169.5	239.9	373.6
Exploratory:			
Productive	89.1	74.1	23.3
Dry	0.9	1.1	1.0
Total	90.0	75.2	24.3

As of December 31, 2013, the Company was participating in the drilling of 5 gross development and 11 gross exploratory wells, with the Company's interest equivalent to 2.2 wells and 9.4 wells, respectively. In addition to the development wells drilled, the Company drilled 9.8, 47.8 and 29.1 net service wells during 2013, 2012 and 2011, respectively.

Productive Wells and Acreage: The following table sets forth the total gross and net productive gas and oil wells as of December 31, 2013, and developed and undeveloped acreage as of the latest practicable date prior to year-end:

	Gross	Net
Oil wells	4,876	3,262
Gas wells	3,305	1,616
Developed acreage	654,848	480,983
Undeveloped acreage	164,416	112,732

There were 10 wells with multiple completions in 2013. All wells and acreage are located onshore in the United States, with the majority of the net undeveloped acreage located in Texas and Colorado.

Concentration of Credit Risk: Revenues and related accounts receivable from oil and gas operations primarily are generated from the sale of produced oil and natural gas to energy marketing companies. Such sales are typically made on an unsecured credit basis with payment due the month following delivery. This concentration of sales to the energy marketing industry has the potential to affect the Company's overall exposure to credit risk, either positively or negatively, in that the Company's oil and gas purchasers may be affected similarly by changes in economic, industry or other conditions. Energen Resources considers the credit quality of its purchasers and, in certain instances, may require credit assurances such as a deposit, letter of credit or parent guarantee. The two largest oil and gas purchasers accounted for approximately 35 percent and 12 percent of Energen Resources' accounts receivable for commodity sales as of December 31, 2013. Energen Resources' other purchasers each accounted for less than 9 percent of these accounts receivable as of December 31, 2013. During the year ended December 31, 2013, Plains Marketing, LP, accounted for approximately 25 percent of consolidated total operating revenues. All other oil and gas purchasers each accounted for less than 10 percent of consolidated total operating revenues for the year ended December 31, 2013.

Risk Management: Energen Resources attempts to lower the commodity price risk associated with its oil and natural gas business through the use of swaps and basis hedges. Energen Resources does not hedge more than 80 percent of its estimated annual production. Energen Resources recognizes all derivatives on the balance sheet and measures all derivatives at fair value. Prior to June 30, 2013, the Company utilized cash flow hedge accounting where applicable for its derivative transactions.

Effective June 30, 2013, the Company elected to discontinue the use of cash flow hedge accounting and to dedesignate all remaining derivative commodity instruments that were previously designated as cash flow hedges. As a result of discontinuing hedge accounting, any gains or losses from inception of the hedge to June 30, 2013 were frozen and will remain in accumulated other comprehensive income until the forecasted transactions actually occur. Any subsequent gains or losses will be accounted for as mark-to-market and recognized immediately through operating revenues. As a result of the Company’s election to discontinue hedge accounting, all derivative transactions entered into subsequent to June 30, 2013 are accounted for as mark-to-market transactions with gains or losses recognized in operating revenues in the period of change.

See the Forward-Looking Statements preceding Item 1, Business, and Item 1A, Risk Factors, for further discussion with respect to price and other risks.

- Natural Gas Distribution

General: Alagasco is the largest natural gas distribution utility in the state of Alabama. Alagasco purchases natural gas through interstate and intrastate suppliers and distributes the purchased gas through its distribution facilities for sale to residential, commercial and industrial customers and other end-users of natural gas. Alagasco also provides transportation services to large industrial and commercial customers located on its distribution system. These transportation customers, using Alagasco as their agent or acting on their own, purchase gas directly from marketers or suppliers and arrange for delivery of the gas into the Alagasco distribution system. Alagasco charges a fee to transport such customer-owned gas through its distribution system to the customers’ facilities.

Alagasco’s service territory is located in central and parts of north Alabama and includes 187 cities and communities in 28 counties. The aggregate population of the counties served by Alagasco is estimated to be 2.5 million. Among the cities served by Alagasco are Birmingham, the center of the largest metropolitan area in Alabama, and Montgomery, the state capital. During 2013, Alagasco served an average of 391,093 residential customers and 31,174 commercial, industrial and transportation customers. The Alagasco distribution system includes approximately 11,229 miles of main and more than 12,015 miles of service lines, odorization and regulation facilities, and customer meters.

APSC Regulation: As an Alabama utility, Alagasco is subject to regulation by the Alabama Public Service Commission (APSC) which established the Rate Stabilization and Equalization (RSE) rate-setting process in 1983. The Alagasco’s current RSE order had an original term extending through December 31, 2014. On December 20, 2013, the APSC issued a final written order modifying RSE effective January 1, 2014 as follows. The term will continue beyond September 30, 2018, unless the APSC enters an order to the contrary in a manner consistent with law. In the event of unforeseen circumstances, whether physical or economic, of the nature of force majeure and including a change in control the APSC and Alagasco will consult in good faith with respect to modifications, if any. Alagasco’s allowed range of return on average common equity will be 10.5 percent to 10.95 percent with an adjusting point of 10.8 percent. Alagasco is eligible to receive a performance-based adjustment of 5 basis points to the return on equity adjusting point, based on meeting certain customer satisfaction criteria. The equity upon which a return will be permitted cannot exceed 56.5 percent of total capitalization, subject to certain adjustments. The inflation-based Cost Control Mechanism (CCM) will be adjusted to allow annual increases to operations and maintenance (O&M) expense using the June Consumer Price Index For All Urban Consumers (Index Range) each rate year plus or minus 1.75 percent and from 2007 actual expenses, adjusted for inflation using the Index Range.

Alagasco's allowed range of return on average equity was 13.15 percent to 13.65 percent through December 31, 2013. Under RSE, the APSC conducts quarterly reviews to determine whether Alagasco's return on average equity at the end of the rate year will be within the allowed range of return. Reductions in rates can be made quarterly to bring the projected return within the allowed range; increases, however, are allowed only once each rate year, effective December 1, and cannot exceed 4 percent of prior-year revenues. Through December 31, 2013, RSE limited the utility's equity upon which a return is permitted to 55 percent of total capitalization, subject to certain adjustments. Currently, under the inflation-based CCM established by the APSC, if the percentage change in O&M expense on an aggregate basis falls within a range of 0.75 points above or below the percentage change in the September Index Range, no adjustment is required. If the change in O&M expense on an aggregate basis exceeds the Index Range, three-quarters of the difference is returned to customers. To the extent the change is less than the Index Range, the utility benefits by one-half of the difference through future rate adjustments. The O&M expense base for measurement purposes will be set at the prior year's actual O&M expense amount unless Alagasco exceeds the top of the Index Range in two successive years, in which case the base for the following year will be set at the top of the Index Range. Certain items that fluctuate based on situations demonstrated to be beyond Alagasco’s control may be excluded from the CCM calculation.

Alagasco’s rate schedules for natural gas distribution charges contain a Gas Supply Adjustment (GSA) rider, established in 1993, which permits the pass-through to customers of changes in the cost of gas supply. Alagasco’s tariff provides a temperature adjustment mechanism, also included in the GSA, that is designed to moderate the impact of departures from normal temperatures on Alagasco’s earnings. The temperature adjustment applies primarily to residential, small commercial and small industrial customers. Other non-temperature weather related conditions that may affect customer usage are not included in the temperature adjustment.

The APSC approved an Enhanced Stability Reserve (ESR) in 1998 which was subsequently modified and expanded in 2010. As currently approved, the ESR provides deferred treatment and recovery for the following: (1) extraordinary O&M expenses related to environmental response costs; (2) extraordinary O&M expenses related to self insurance costs that exceed $1 million per occurrence; (3) extraordinary O&M expenses, other than environmental response costs and self insurance costs, resulting from a single force majeure event or multiple force majeure events greater than $275,000 and $412,500, respectively, during a rate year; and (4) negative individual large commercial and industrial customer budget revenue variances that exceed $350,000 during a rate year.

Charges to the ESR are subject to certain limitations which may disallow deferred treatment and which prescribe the timing of recovery. Funding to the ESR is provided as a reduction to the refundable negative salvage balance over its nine year term beginning December 1, 2010. Subsequent to the nine year period and subject to APSC authorization, Alagasco anticipates recovering underfunded ESR balances over a five year period with an annual limitation of $660,000.

Gas Supply: Alagasco’s distribution system is connected to two major interstate natural gas pipeline systems, Southern Natural Gas Company (Southern) and Transcontinental Gas Pipe Line Company (Transco). It is also connected to two intrastate natural gas pipeline systems and to Alagasco’s two liquified natural gas (LNG) facilities.

Alagasco purchases natural gas from various natural gas producers and marketers. Certain volumes are purchased under firm contractual commitments with other volumes purchased on a spot market basis. The purchased volumes are delivered to Alagasco’s system using a variety of firm transportation, interruptible transportation and storage capacity arrangements designed to meet the system’s varying levels of demand. Alagasco’s LNG facilities can provide the system with up to an additional 200,000 thousand cubic feet per day (Mcfd) of natural gas to meet peak day demand.

As of December 31, 2013, Alagasco had the following contracts in place for firm natural gas pipeline transportation and storage services:

	December 31, 2013 (Mcfd)
Southern firm transportation	112,933
Southern storage and no notice transportation	231,679
Transco firm transportation	70,000
Various intrastate transportation	20,240

Competition: The price of natural gas is a significant competitive factor in Alagasco’s service territory, particularly among large commercial and industrial transportation customers. Propane, coal and fuel oil are readily available, and many industrial customers have the capability to switch to alternate fuels and alternate sources of gas. In the residential and small commercial and industrial markets, electricity is the principal competitor. With the support of the APSC, Alagasco has implemented a variety of programs to help it compete for gas load in all market segments. The

Company has been effective at utilizing these programs to avoid load loss to competitive fuels.

Alagasco's Transportation Tariff allows the Company to transport gas for large commercial and industrial customers rather than buying and reselling it to them and is based on Alagasco's sales profit margin so that operating margins are unaffected. During 2013, substantially all of Alagasco's large commercial and industrial customer deliveries involved the transportation of customer-owned gas.

Natural gas service available to Alagasco customers falls into two broad categories: interruptible and firm. Interruptible service contractually is subject to interruption at Alagasco's discretion. The most common reason for such interruption is curtailment during periods of peak core market heating demand. Customers who contract for interruptible service can generally adjust production schedules or switch to alternate fuels during periods of service interruption or curtailment. More expensive firm service, on the other hand, generally is not subject to interruption and is provided to residential and small commercial and industrial customers. These core market customers depend on natural gas primarily for space heating.

Customers: Alagasco is a mature utility operating in a slow-growth service area which includes municipalities that have in recent years experienced population declines. Alagasco's average customer count for 2013 declined approximately 0.6 percent from 2012 and reflected a moderation in decline over the five-year trend. Other factors impacting Alagasco's average customer count include recent weather trends, enhanced credit and collection efforts and the loss of customers due to a 2011 weather event.

Seasonality: Alagasco's gas distribution business is highly seasonal since a material portion of the utility's total sales and delivery volumes relate to space heating customers. Alagasco's tariff includes a Temperature Adjustment Rider primarily for residential, small commercial and small industrial customers that moderates the impact of departures from normal temperatures on Alagasco's earnings. The adjustments are made through the GSA.

•Environmental Matters and Climate Change

Various federal, state and local environmental laws and regulations apply to the operations of Energen Resources and Alagasco. Historically, the cost of environmental compliance has not materially affected the Company's financial position, results of operations or cash flows. New regulations, enforcement policies, claims for damages or other events could result in significant unanticipated costs.

Federal, state and local legislative bodies and agencies frequently exercise their respective authority to adopt new laws and regulations and to amend and interpret existing laws and regulations. Such law and regulation changes may occur with little prior notification, subject the Company to cost increases, and impose restrictions and limitations on the Company's operations. Currently, there are various proposed law and regulatory changes with the potential to materially impact the Company. Such proposals include, but are not limited to, measures dealing with hydraulic fracturing, emission limits and reporting and the repeal of certain oil and gas tax incentives and deductions. Due to the nature of the political and regulatory processes and based on its consideration of existing proposals, the Company is unable to determine whether such proposed laws and regulations are reasonably likely to be enacted or to determine, if enacted, the magnitude of the potential impact of such laws.

Energen regularly utilizes hydraulic fracturing in its drilling and completion activities. The Company's first widespread use of hydraulic fracturing occurred during the 1980s when we successfully pioneered the exploration and development of coalbed methane in Alabama's Black Warrior Basin.

Hydraulic fracturing is a well-established reservoir stimulation technique used throughout the oil and gas industry for more than 60 years. After a well has been drilled, hydraulic fracturing is used during the completion process to form small fractures in the target formation through which the natural gas or oil can flow. The fractures are created when a water-based fluid is pumped at a calculated rate and pressure into the natural gas- or crude oil-bearing rock. The fracture fluid is a mixture composed primarily of water and sand or inert ceramic, sand-like grains; it also contains a small percentage of special purpose chemical additives (which are highly diluted-typically less than one percent by volume) that can vary by project. The millimeter-thick cracks or fractures in the target formation are propped open by the sand, thereby allowing the natural gas or crude oil to flow from tight (low permeability) reservoirs into the well bore.

Various states in which we operate have adopted a variety of well construction, set back, and disclosure regulations limiting how drilling can be performed and requiring various degrees of chemical and water usage disclosure for operators that employ hydraulic fracturing. We are complying with these additional regulations as part of our routine operations and within the normal execution of our business plan. The adoption of additional federal or state regulations, however, could impose significant new costs and challenges. For example, adoption of new hydraulic fracturing permitting requirements could significantly delay or prevent new drilling. Adoption of new regulatory restrictions on the use of hydraulic fracturing could reduce the amount of oil and gas that we are able to recover from our reserves. The degree to which additional oil and gas industry regulation may impact our future operations and results will depend on the extent to which we utilize the regulated activity and whether the geographic locations in which we operate are subject to the new regulation.

Existing federal, state and local environmental laws and regulations also have the potential to increase costs, reduce liquidity, delay operations and otherwise alter business operations. These existing laws and regulations include, but are not limited to, the Clean Air Act; the Clean Water Act; Oil Pollution Prevention: Spill Prevention, Control, and Countermeasure regulations;

Toxic Substances Control Act; Resource Conservation and Recovery Act; and the Federal Endangered Species Act. Compliance with these and other environmental laws and regulations is undertaken as part of the Company's routine operations. The Company does not separately track costs associated with these routine compliance activities.

Climate change, whether arising through natural occurrences or through the impact of human activities, may have a significant impact upon the operations of Energen Resources and Alagasco. Volatile weather patterns and the resulting environmental impact may adversely impact the results of operations, financial position and cash flows of the Company. The Company is unable to predict the timing or manifestation of climate change or reliably estimate the impact to the Company. However, climate change could affect the operations of the Company as follows:

- sustained increases or decreases to the supply and demand of oil, natural gas and natural gas liquids;
- positive or negative changes to usage and customer count at Alagasco from prolonged increases or decreases in average temperature for Alagasco's central and north Alabama service territory;
- potential disruption to third party facilities to which Energen Resources delivers and from which Alagasco is served. Such facilities include third party oil and gas gathering, transportation, processing and storage facilities and are typically limited in number and geographically concentrated.

Under oversight of the Site Remediation Section of the Railroad Commission of Texas, the Company is currently in the process of cleanup and remediation of oil and gas wastes in nine reserve pits in Mitchell County, Texas. The Company estimates that the cleanup, remediation and related costs will approximate $2.1 million of which $1.9 million has been incurred and $0.2 million has been reserved.

During January 2014, Energen Resources responded to a General Notice and Information Request from the Environmental Protection Agency (EPA) regarding the Reef Environmental Site in Sylacauga, Talladega County, Alabama. The letter identifies Energen Resources as a potentially responsible party (PRP) under CERCLA for the cleanup of the Site. In 2008, Energen hired a third party to transport approximately 3,000 gallons of non-hazardous wastewater to Reef Environmental for wastewater treatment. Reef Environmental ceased operating its wastewater treatment system in 2010. Due to its one time use of Reef Environmental for a small volume of non-hazardous wastewater, Energen Resources has not accrued a liability for cleanup of the Site.

Alagasco is in the chain of title of nine former manufactured gas plant sites, four of which it still owns, and five former manufactured gas distribution sites, one of which it still owns. Management expects that, should future remediation of the sites be required, Alagasco's share of the remediation costs will not materially affect the financial position of Alagasco. During 2011, a removal action was completed at the Huntsville, Alabama manufactured gas plant site pursuant to an Administrative Settlement Agreement and Order on Consent among the United States EPA, Alagasco and the current site owner.

In 2012, Alagasco responded to an EPA Request for Information Pursuant to Section 104 of CERCLA relating to the 35th Avenue Superfund Site located in North Birmingham, Jefferson County, Alabama. The Request related to a former site of a manufactured gas distribution facility owned by Alagasco and located in the vicinity of the 35th Avenue Superfund Site. In September 2013, Alagasco received from the EPA a General Notice Letter and Invitation to Conduct a Removal Action at the 35th Avenue Superfund Site. The letter identifies Alagasco as a PRP under CERCLA for the cleanup of the Site or costs the EPA incurs in cleaning up the Site. The EPA also offered the PRP group the opportunity to conduct Phase I of the proposed removal action which involved removal activities at approximately 50 residences that purportedly exceed certain risk levels for contamination. Alagasco has discussed its designation as a PRP further with the EPA, and Alagasco has requested additional information from the EPA regarding its designation as a PRP. Alagasco has not been provided information at this time that would allow it to determine the extent, if any, of its potential liability with respect to the 35th Avenue Superfund Site and the proposed removal action, and therefore Alagasco has not agreed to undertake the proposed removal activities and no amount has been accrued as of December 31, 2013.

• Employees

The Company has approximately 1,434 employees, of which Alagasco employs 993 and Energen Resources employs 441. The Company believes that its relations with employees are good.

ITEM 1A. RISK FACTORS

The future success and continued viability of Energen and its businesses, like any venture, is subject to many recognized and unrecognized risks and uncertainties. Such risks and uncertainties could cause actual results to differ materially from those contained in forward-looking statements made in this report and presented elsewhere by management. The following list identifies and briefly summarizes certain risk factors, and should not be viewed as complete or comprehensive. The Company undertakes no obligation to correct or update such risk factors whether as a result of new information, future events or otherwise. These risk factors should be read in conjunction with the Company's disclosure specific to Forward-Looking Statements made elsewhere in this report.

Commodity prices for crude oil and natural gas are volatile, and a substantial reduction in commodity prices could adversely affect the Company's results and the carrying value of its oil and natural gas properties: The Company and Alagasco are significantly influenced by commodity prices. Historical markets for oil, natural gas and natural gas liquids have been volatile. Energen Resources' revenues, operating results, profitability and cash flows depend primarily upon the prices realized for its oil, gas and natural gas liquid production. Additionally, downward commodity price trends may impact expected cash flows from future production and potentially reduce the carrying value of Company-owned oil and natural gas properties. Alagasco's competitive position and customer demand is significantly influenced by prices for natural gas which are passed-through to customers.

Market conditions or a downgrade in the credit ratings of the Company or its subsidiaries could negatively impact its cost of and ability to access capital for future development and working capital needs: The Company and its subsidiaries rely on access to credit markets. The availability and cost of credit market access is significantly influenced by market events and rating agency evaluations for lenders, the Company and its subsidiaries. In addition to operating results, business decisions relating to recapitalization, refinancing, restructuring, acquisition and disposition (including by sale, spin-off or distribution) transactions involving the Company, Energen Resources or Alagasco may negatively impact market and rating agency considerations regarding the credit of the Company or its subsidiaries, and the management of the Company periodically considers these types of transactions. Market volatility and credit market disruption may severely limit credit availability and issuer credit ratings can change rapidly. Events negatively affecting credit ratings and credit market liquidity could increase borrowing costs, limit availability of funds to the Company and adversely affect the price of outstanding debt securities.

Energen Resources' hedging activities may prevent Energen Resources from benefiting fully from price increases and expose Energen Resources to other risks, including counterparty credit risk: Although Energen Resources makes use of futures, swaps, options, collars and fixed-price contracts to mitigate price risk, fluctuations in future oil, gas and natural gas liquids prices could materially affect the Company's financial position, results of operations and cash flows; furthermore, such risk mitigation activities may cause the Company's financial position and results of operations to be materially different from results that would have been obtained had such risk mitigation activities not occurred. The effectiveness of such risk mitigation assumes that counterparties maintain satisfactory credit quality. The effectiveness of such risk mitigation also assumes that actual sales volumes will generally meet or exceed the volumes subject to the futures, swaps, options, collars and fixed-price contracts. A substantial failure to meet sales volume targets, whether caused by miscalculations, weather events, natural disaster, accident, mechanical failure, criminal act or otherwise, could leave Energen Resources financially exposed to its counterparties and result in material adverse financial consequences to Energen Resources and the Company. The adverse effect could be increased if the adverse event was widespread enough to move market prices against Energen Resources' position. In addition, various existing and pending financial reform rules and regulations could have an adverse effect on the ability of Energen Resources to use derivative instruments which could have a material adverse effect on our financial position, results of operations and cash flows.

The Company is exposed to counterparty credit risk as a result of its concentrated customer base: Revenues and related accounts receivable from oil and gas operations primarily are generated from the sale of produced oil, natural gas and natural gas liquids to a small number of energy marketing companies. Such sales are typically made on an unsecured credit basis with payment due the month following delivery. This concentration of sales to a limited number of customers in the energy marketing industry has the potential to affect the Company’s overall exposure to credit risk, either positively or negatively, based on changes in economic, industry or other conditions specific to a single customer or to the energy marketing industry generally. Energen Resources considers the credit quality of its customers and, in certain instances, may require credit assurances such as a deposit, letter of credit or parent guarantee.

The Company’s operations depend upon the use of third party facilities and an interruption of its ability to utilize these facilities may adversely affect its financial condition and results of operations: Energen Resources delivers to and Alagasco is served by third party facilities. These facilities include third party oil and gas gathering, transportation, processing and storage facilities. Energen Resources relies upon such facilities for access to markets for its production. Alagasco relies upon such facilities for access to natural gas supplies. Such facilities are typically limited in number and geographically concentrated. An extended interruption of access to or service from these facilities, whether caused by weather events, natural disaster, accident, mechanical failure, criminal act or otherwise could result in material adverse financial consequences to Energen Resources, Alagasco and the Company.

The Company's oil and natural gas reserves are estimates, and actual future production may vary significantly and may also be negatively impacted by its inability to invest in production on planned timelines: There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and in projecting future rates of production and timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates. In the event Energen Resources is unable to fully invest its planned development, acquisition and exploratory expenditures, future operating revenues, production, and proved reserves could be negatively affected. The drilling of development and exploratory wells can involve significant risks, including those related to timing, success rates and cost overruns, and these risks can be affected by lease and rig availability, complex geology and other factors. Anticipated drilling plans and capital expenditures may also change due to weather, manpower and equipment availability, changing emphasis by management and a variety of other factors which could result in actual drilling and capital expenditures being substantially different than currently planned.

The Company's operations involve operational risk including risk of personal injury, property damage and environmental damage and its insurance policies do not cover all such risks: Inherent in the oil and gas production activities of Energen Resources and the gas distribution activities of Alagasco are a variety of hazards and operation risks, such as:

- Pipeline and storage leaks, ruptures and spills;
- Equipment malfunctions and mechanical failures;
- Fires and explosions;
- Well blowouts, explosions and cratering; and
- Soil, surface water or groundwater contamination from petroleum constituents, hydraulic fracturing fluid, or produced water.

Such events could result in loss of human life, significant damage to property, environmental pollution, impairment of operations and substantial financial losses. The location of certain of our pipeline and storage facilities near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. In accordance with customary industry practices, the Company maintains insurance against some, but not all, of these risks and losses and the insurance coverages are subject to retention levels and coverage limits. The occurrence of any of these events could adversely affect Energen Resources', Alagasco's and the Company's financial positions, results of operations and cash flows.

Alagasco operates in a limited service territory and is therefore subject to concentrated regional risks which may negatively affect Alagasco's financial condition and results of operations: Alagasco's utility customers are geographically concentrated in central and north Alabama. Significant economic, weather, natural disaster, criminal act or other events that adversely affect this region could adversely affect Alagasco and the Company.

The Company is subject to numerous federal, state and local laws and regulations that may require significant expenditures or impose significant restrictions on its operations: Energen and Alagasco are subject to extensive federal, state and local regulation which significantly influences operations. Although the Company believes that operations generally comply with applicable laws and regulations, failure to comply could result in the suspension or termination of operations and subject the Company to administrative, civil and criminal penalties. Federal, state and local legislative bodies and agencies frequently exercise their respective authority to adopt new laws and regulations and to amend, modify and interpret existing laws and regulations. Such changes can subject the Company to significant tax or cost increases and can impose significant restrictions and limitations on the Company's operations.

The Company's business could be negatively impacted by security threats, including cybersecurity threats, and related disruptions: The Company relies on its information technology infrastructure to process, transmit and store electronic information critical for the efficient operation of its business and day-to-day operations. All information systems are potentially vulnerable to security threats, including hacking, viruses, other malicious software, and other unlawful attempts to disrupt or gain access to such systems. Breaches in the Company's information technology infrastructure could lead to a material disruption in its business, including the theft, destruction, loss, misappropriation or release of confidential data or other business information, and may have a material adverse effect on the Company's operations, financial position and results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None

ITEM 2. PROPERTIES

The corporate headquarters of Energen, Energen Resources and Alagasco are located in leased office space in Birmingham, Alabama. See the discussion under Item 1, Business, for further information related to Energen Resources' and Alagasco's business operations. Information concerning Energen Resources' production and reserves is summarized in the table below and included in Note 19, Oil and Gas Operations (Unaudited), in the Notes to Financial Statements. See Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations for a discussion of the future outlook and expectations for Energen Resources and Alagasco and additional information regarding Energen Resources' production, revenue and production costs.

Oil and Gas Operations

Energen Resources focuses on increasing its production and proved reserves through the development and exploration of onshore North American oil and gas properties. Energen Resources maintains district offices in Midland, Texas; Farmington, New Mexico; and Arcadia, Louisiana.

The major areas of operations include (1) the Permian Basin, (2) the San Juan Basin and (3) North Louisiana/East Texas as highlighted on the above map. As of December 31, 2013, North Louisiana/East Texas natural gas and oil properties were classified as held-for-sale and the associated operating results were reflected in discontinued operations.

The following table sets forth the production volumes, proved reserves and reserves-to-production ratio by area:

	Year ended December 31, 2013 Production Volumes (MBOE)	December 31, 2013 Proved Reserves (MBOE)	December 31, 2013 Reserves-to-Production Ratio
Permian Basin	14,187	246,586	17.38 years
San Juan Basin	9,011	96,448	10.70 years
North Louisiana/East Texas*	617	3,877	6.28 years
Other	83	924	11.13 years
Total excluding Black Warrior Basin	23,898	347,835	14.55 years
Black Warrior Basin (sold during 2013)	1,464	—	—
Total	25,362	—	—

* North Louisiana/East Texas were classified as held-for-sale as of December 31, 2013.

The following table sets forth proved reserves by area as of December 31, 2013:

	Gas MMcf	Oil MBbl	NGL MBbl
Permian Basin	232,345	163,716	44,147
San Juan Basin	460,097	900	18,864
North Louisiana/East Texas*	22,716	91	—
Other	4,567	163	—
Total	719,725	164,870	63,011

* North Louisiana/East Texas were classified as held-for-sale as of December 31, 2013.

See Note 19, Oil and Gas Operations (Unaudited), in the Notes to Financial Statements for the changes to proved reserves during the years ended December 31, 2013, 2012 and 2011 of natural gas, oil, and natural gas liquids.

The following table sets forth proved developed reserves by area as of December 31, 2013:

	Gas MMcf	Oil MBbl	NGL MBbl
Permian Basin	135,925	112,641	23,223
San Juan Basin	460,097	900	18,864
North Louisiana/East Texas*	22,716	91	—
Other	4,567	163	—
Total	623,305	113,795	42,087

* North Louisiana/East Texas were classified as held-for-sale as of December 31, 2013.

The following table sets forth proved undeveloped reserves by area as of December 31, 2013:

	Gas MMcf	Oil MBbl	NGL MBbl
Permian Basin	96,420	51,075	20,924
Total	96,420	51,075	20,924

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The following table sets forth the reconciliation of proved undeveloped reserves:

Year ended December 31, 2013	Total MMBOE
Balance at beginning of period	85.9
Undeveloped reserves transferred to developed reserves	(20.3)
Revisions	5.7
Extensions and discoveries	16.7
Balance at end of period	88.0

Undeveloped reserves transferred to developed reserves reflect capital expenditures of approximately $414 million during the year ended December 31, 2013 in development of previously proved undeveloped reserves. Proved undeveloped reserves additions were one offset location away from producing wells where our geologic interpretation and experience indicate the reservoirs were continuous across those locations. The technologies associated with these additions to reserve estimates are analysis of well production data, geophysical data, wireline and core data. Revisions largely relate to well performance in the Permian Basin of approximately 13.4 MMBOE partially offset by a reduction in reserves of 5.3 MMBOE associated with the five-year proved undeveloped reserve development rules.

Estimated proved reserves as of December 31, 2013 are based upon studies for each of our properties prepared by Company engineers and audited by Ryder Scott Company, L.P. (Ryder Scott) and T. Scott Hickman and Associates, Inc. (T. Scott Hickman), independent oil and gas reservoir engineers. Calculations were prepared using geological and engineering methods widely used and referred to by professionals in the industry and in accordance with Securities and Exchange Commission (SEC) guidelines.

A Senior Vice President at Ryder Scott is the technical person primarily responsible for overseeing the audit of the reserves. The Senior Vice President has a Bachelor of Science degree in Mechanical Engineering and is a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers. He has been an employee of Ryder Scott since 1982 and also serves as chief technical advisor of unconventional reserves evaluation. A Petroleum Consultant at T. Scott Hickman is the technical person primarily responsible for overseeing the audit of the reserves. He has a Bachelor of Science degree in Petroleum Engineering and is a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers. He has been employed by T. Scott Hickman since 1983. The Vice President of Acquisitions and Reservoir Engineering is the technical person primarily responsible for overseeing reserves on behalf of Energen Resources. His background includes a Bachelor of Science degree in Mechanical Engineering and membership in the Society of Petroleum Engineers. He is a registered Professional Engineer in the State of Alabama with more than 30-years experience evaluating oil and natural gas properties and estimating reserves.

The Company relies upon certain internal controls when preparing its reserve estimations. These internal controls include review by the reservoir engineering managers to ensure the correct reserve methodology has been applied for each specific property and that the reserves are properly categorized in accordance with SEC guidelines. The reservoir engineering managers also affirm the accuracy of the data used in the reserve and associated rate forecast, provide a review of the procedures used to input pricing data and provide a review of the working and net interest factors to ensure that factors are adequately reflected in the engineering analysis.

Net production forecasts are compared to historical sales volumes to check for reasonableness, and operating costs and severance taxes calculated in the reserve report are compared to historical accounting data to help ensure proper cost estimates are used. A reserve table is generated comparing the previous year’s reserves to current year reserve estimates to determine variances. This table is reviewed by the Vice President of Acquisitions and Reservoir Engineering and the Chief Operating Officer of Energen Resources. Revisions and additions are investigated and explained.

Reserve estimates of proved reserves are sent to independent reservoir engineers for audit and verification. For 2013, approximately 98 percent of all proved reserves were audited by the independent reservoir engineers which audit engineering procedures, check the reserve estimates for reasonableness and check that the reserves are properly classified.

The following table sets forth the standard pressure base in pounds-force per square inch absolute (psia) for each state in which Energen Resources has wells:

Texas	14.65 psia
Colorado	14.73 psia
Louisiana, New Mexico	15.025 psia

The following table sets forth the total net productive oil and gas wells by area as of December 31, 2013, and developed and undeveloped acreage as of the latest practicable date prior to year-end:

	Net Wells	Net Developed Acreage	Net Undeveloped Acreage
Permian Basin	3,241	172,496	81,043
San Juan Basin	1,454	281,676	31,689
North Louisiana/East Texas*	175	20,720	—
Other	8	6,091	—
Total	4,878	480,983	112,732

* North Louisiana/East Texas were classified as held-for-sale as of December 31, 2013.

The following table sets forth expiration dates for gross and net undeveloped acreage at year end as of December 31, 2013:

	Years ending December 31,							
	2014		2015		2016		Thereafter	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Permian	11,400	7,537	43,938	31,513	13,724	13,110	35,667	28,883
San Juan	498	245	1,619	919	20,731	5,982	36,839	24,543
Total*	11,898	7,782	45,557	32,432	34,455	19,092	72,506	53,426

* Our capital plan contemplates avoiding a significant portion of these lease expirations.

Energen Resources has 5.6 MMBOE of proved undeveloped reserves on leased acreage which is not held by production and is expected to be developed after the primary term of the leases. Drilling associated with these reserves is expected to occur under the continuous development provisions of the leases. The amount represents approximately 6 percent of the 88 MMBOE total proved undeveloped reserves and approximately 2 percent of the 347.8 MMBOE total proved reserves at December 31, 2013. We believe both of these amounts to be immaterial to our operations.

Energen Resources sells oil, natural gas, and natural gas liquids under a variety of contractual arrangements, some of which specify the delivery of a fixed and determinable quantity (firm volumes). Energen Resources is contractually committed to deliver approximately 37.8 billion cubic feet (net) of natural gas through March 2015. The Company expects to fulfill delivery commitments through production of existing proved reserves.

	Gas MMcf
San Juan Basin	37,823

Natural Gas Distribution

The properties of Alagasco consist primarily of its gas distribution system, which includes approximately 11,229 miles of main and more than 12,015 miles of service lines, odorization and regulation facilities, and customer meters. Alagasco also has two LNG facilities, thirteen operation centers, two business centers, and other related property and equipment, some of which are leased by Alagasco.

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ITEM 3. LEGAL PROCEEDINGS

Energen and its affiliates are, from time to time, parties to various pending or threatened legal proceedings. Certain of these lawsuits include claims for punitive damages in addition to other specified relief. Various pending or threatened legal proceedings are in progress currently. See Note 7, Commitments and Contingencies, in the Notes to Financial Statements for further discussion with respect to legal proceedings.

ITEM 4. MINE SAFETY DISCLOSURES

None

EXECUTIVE OFFICERS OF THE REGISTRANTS

Name	Age	Position (1)
James T. McManus, II	55	Chairman, Chief Executive Officer and President of Energen and Chairman and Chief Executive Officer of Alagasco (2)
Charles W. Porter, Jr.	49	Vice President, Chief Financial Officer and Treasurer of Energen and Alagasco (3)
John S. Richardson	56	President and Chief Operating Officer of Energen Resources (4)
Dudley C. Reynolds	60	President and Chief Operating Officer of Alagasco (5)
J. David Woodruff, Jr.	57	Vice President, General Counsel and Secretary of Energen and Alagasco (6)
Russell E. Lynch, Jr.	40	Vice President and Controller of Energen (7)

Notes:
(1) All executive officers of Energen have been employed by Energen or a subsidiary for the past five years. Officers serve at the pleasure of the Board of Directors.

(2) Mr. McManus has been employed by the Company in various capacities since 1986. He was elected Executive Vice President and Chief Operating Officer of Energen Resources in October 1995 and President of Energen Resources in April 1997. He was elected President and Chief Operating Officer of Energen effective January 1, 2006 and Chief Executive Officer of Energen and each of its subsidiaries effective July 1, 2007. He was elected Chairman of the Board of Energen and each of its subsidiaries effective January 1, 2008. Mr. McManus serves as a Director of Energen and each of its subsidiaries.

(3) Mr. Porter has been employed by the Company in various financial capacities since 1989. He was elected Controller of Energen Resources in 1998. In 2001, he was elected Vice President – Finance of Energen Resources. He was elected Vice President, Chief Financial Officer and Treasurer of Energen and each of its subsidiaries effective January 1, 2007.

(4) Mr. Richardson has been employed by the Company in various capacities since 1985. He was elected Vice President – Acquisitions and Engineering of Energen Resources in 1997. He was elected Executive Vice President and Chief Operating Officer of Energen Resources effective January 1, 2006. He was elected President and Chief Operating Officer of Energen Resources effective January 23, 2008.

(5) Mr. Reynolds has been employed by the Company in various capacities since 1980. He was elected General Counsel and Secretary of Energen and each of its subsidiaries in April 1991. He was elected President and Chief Operating Officer of Alagasco effective January 1, 2003.

(6) Mr. Woodruff has been employed by the Company in various capacities since 1986. He was elected Vice President-Legal and Assistant Secretary of Energen and each of its subsidiaries in April 1991. He was elected General Counsel and Secretary of Energen and each of its subsidiaries effective January 1, 2003. He also served as Vice President-Corporate Development of Energen from 1995 to 2010.

(7) Mr. Lynch has been employed by the Company in various capacities since 2001. He was elected Vice President and Controller of Energen effective January 1, 2009.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Quarterly Market Prices and Dividends Paid Per Share

Quarter ended (in dollars)	High	Low	Close	Dividends Paid
March 31, 2012	58.24	47.33	49.15	0.14
June 30, 2012	53.28	40.13	45.13	0.14
September 30, 2012	55.59	43.81	52.41	0.14
December 31, 2012	54.77	41.38	45.09	0.14
March 31, 2013	52.13	44.46	52.01	0.145
June 30, 2013	56.65	45.11	52.26	0.145
September 30, 2013	77.50	52.42	76.39	0.145
December 31, 2013	89.92	65.74	70.75	0.145

Energen's common stock is listed on the New York Stock Exchange under the symbol EGN. On February 14, 2014, there were 5,076 holders of record of Energen's common stock. At the date of this filing, Energen Corporation owned all the issued and outstanding common stock of Alabama Gas Corporation. Energen expects to pay annual cash dividends of $0.60 per share on the Company's common stock in 2014. The amount and timing of all dividend payments is subject to the discretion of the Board of Directors and is based upon business conditions, results of operations, financial conditions and other factors.

The following table summarizes information concerning purchases of equity securities by the issuer:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans	Maximum Number of Shares that May Yet Be Purchased Under the Plans**
October 1, 2013 through October 31, 2013	—	$—	—	8,992,700
November 1, 2013 through November 30, 2013	—	—	—	8,992,700
December 1, 2013 through December 31, 2013	507*	70.08	—	8,992,700
Total	507	$70.08	—	8,992,700

* Acquired in connection with tax withholdings and payment of exercise price on stock compensation plans.
** By resolution adopted May 24, 1994, and supplemented by resolutions adopted April 26, 2000 and June 24, 2006, the Board of Directors authorized the Company to repurchase up to 12,564,400 shares of the Company's common stock. The resolutions do not have an expiration date.

PERFORMANCE GRAPH
Energen Corporation — Comparison of Five-Year Cumulative Shareholder Returns

This graph compares the total shareholder returns of Energen, the Standard & Poor's Composite Stock Index (S&P 500), the Standard & Poor's Supercomposite Oil & Gas Exploration & Production Index (S15OILP), and the Standard & Poor's Supercomposite Gas Utilities Index (S15GASUX). The graph assumes $100 invested at the per-share closing price of the common stock on the New York Exchange Composite Tape on December 31, 2008, in the Company and each of the indices. Total shareholder return includes reinvested dividends.

As of December 31,	2008	2009	2010	2011	2012	2013
S&P 500	$100	$126	$146	$149	$172	$228
Energen	$100	$162	$169	$177	$161	$255
S15OILP	$100	$145	$164	$152	$155	$200
S15GASUX	$100	$126	$147	$177	$177	$230

ITEM 6. SELECTED FINANCIAL DATA

The selected financial data as set forth below should be read in conjunction with the consolidated financial statements and the Notes to Financial Statements included in this Form 10-K.

SELECTED FINANCIAL AND COMMON STOCK DATA
Energen Corporation

Years ended December 31, (dollars in thousands, except per share amounts)	2013	2012	2011	2010	2009
INCOME STATEMENT					
Operating revenues	$1,738,650	$1,540,819	$1,373,113	$1,425,107	$1,273,574
Income from continuing operations	$193,147	$255,220	$224,305	$233,133	$191,643
Net income	$204,554	$253,562	$259,624	$290,807	$256,325
Diluted earnings per average common share from continuing operations	$2.67	$3.53	$3.10	$3.24	$2.67
Diluted earnings per average common share	$2.82	$3.51	$3.59	$4.04	$3.57
BALANCE SHEET					
Total property, plant and equipment, net	$6,003,638	$5,541,636	$4,620,776	$3,719,227	$3,144,469
Total assets	$6,622,212	$6,175,890	$5,237,416	$4,363,560	$3,803,118
Long-term debt	$1,343,464	$1,103,528	$1,153,700	$405,254	$410,786
Total shareholders’ equity	$2,858,019	$2,676,690	$2,432,163	$2,154,043	$1,988,243
COMMON STOCK DATA					
Cash dividends paid per common share	$0.58	$0.56	$0.54	$0.52	$0.50
Diluted average common shares outstanding (000)	72,471	72,316	72,332	72,051	71,885
Price range:					
High	$89.92	$58.24	$65.44	$49.94	$48.89
Low	$44.46	$40.13	$37.22	$40.25	$23.18
Close	$70.75	$45.09	$50.00	$48.26	$46.80

SELECTED BUSINESS SEGMENT DATA
Energen Corporation

Years ended December 31, (dollars in thousands)	2013	2012	2011	2010	2009
OIL AND GAS OPERATIONS					
Operating revenues from continuing operations					
Natural gas	$239,643	$216,073	$281,501	$336,493	$298,865
Oil	865,100	788,937	465,735	403,039	283,247
Natural gas liquids	101,550	85,938	87,464	65,161	67,254
Other	(981)	(1,718)	3,460	642	6,334
Total	$1,205,312	$1,089,230	$838,160	$805,335	$655,700
Non-cash mark-to-market gains (losses) (included in operating revenues from continuing operations above)					
Natural gas	$(3,919)	$(515)	$—	$—	$—
Oil	(43,261)	58,786	(37,473)	(3)	(107)
Natural gas liquids	(652)	479	(114)	—	—
Total	$(47,832)	$58,750	$(37,587)	$(3)	$(107)
Production volumes from continuing operations					
Natural gas (MMcf)	58,104	59,166	54,132	51,778	50,365
Oil (MBbl)	10,364	8,749	6,300	5,109	4,664
Natural gas liquids (MMgal)	135.8	108.1	91.4	79.0	75.2
Production volumes from continuing operations (MBOE)	23,281	21,183	17,499	15,619	14,849
Total production volumes (MBOE)	25,362	24,066	20,448	18,832	18,537
Proved reserves					
Natural gas (MMcf)	719,725	809,128	957,368	954,387	897,546
Oil (MBbl)	164,870	155,348	129,578	103,262	77,963
Natural gas liquids (MBbl)	63,011	56,155	53,957	40,601	30,257
Total (MMcfe)	2,087,010	2,078,154	2,058,594	1,817,565	1,546,866
Total (MBOE)	347,835	346,359	343,099	302,928	257,811
Other data from continuing operations					
Lease operating expense					
Lease operating expense and other	$284,053	$224,503	$174,778	$155,359	$151,651
Production taxes	67,488	53,690	51,583	38,686	31,852
Total	$351,541	$278,193	$226,361	$194,045	$183,503
Depreciation, depletion and amortization	$453,474	$343,183	$213,841	$168,016	$146,946
Capital expenditures	$1,104,745	$1,291,211	$1,115,452	$717,782	$427,399
Exploration expense	$27,942	$19,356	$12,967	$64,562	$10,225
Operating income	$257,963	$369,765	$308,561	$315,990	$252,927
NATURAL GAS DISTRIBUTION					
Operating revenues					
Residential	$340,563	$277,698	$343,740	$414,870	$398,289
Commercial and industrial	136,990	115,711	136,469	159,658	161,543
Transportation	61,254	58,857	55,234	57,049	53,856
Other	(5,469)	(677)	(490)	(11,805)	4,186
Total	$533,338	$451,589	$534,953	$619,772	$617,874

Gas delivery volumes (MMcf)					
Residential	20,279	16,014	21,132	24,463	20,921
Commercial and industrial	9,968	8,372	9,994	10,985	9,934
Transportation	47,534	48,106	44,614	46,479	40,903
Total	77,781	72,492	75,740	81,927	71,758

Average number of customers					
Residential	391,093	393,467	395,766	404,697	409,214
Commercial, industrial and transportation	31,174	31,450	31,840	32,632	33,264
Total	422,267	424,917	427,606	437,329	442,478
Other data					
Depreciation and amortization	$43,907	$42,270	$39,916	$44,042	$50,995
Capital expenditures	$88,769	$71,869	$73,984	$93,566	$77,809
Operating income	$93,768	$93,216	$86,216	$88,383	$83,984

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

RESULTS OF OPERATIONS

Consolidated Net Income

Energen Corporation’s net income for the year ended December 31, 2013 totaled $204.6 million, or $2.82 per diluted share compared to the year ended December 31, 2012 net income of $253.6 million, or $3.51 per diluted share. This 19.7 percent decrease in earnings per diluted share (EPS) largely reflected increased depreciation, depletion and amortization (DD&A) expense, a year-over-year after-tax $67.8 million non-cash mark-to-market decrease in derivatives (resulting from an after-tax $30.6 million non-cash mark-to-market loss on derivatives for 2013 and an after-tax $37.2 million non-cash mark-to-market gain on derivatives for 2012), higher lease operating expense excluding production taxes, increased administrative expense, increased production taxes, higher exploration expense, lower commodity prices for natural gas liquids and increased interest expense. Positively affecting net income was the impact of a net 2.1 million barrels of oil equivalent (MMBOE) increase in production volumes from Energen Resources Corporation, Energen’s oil and gas subsidiary, and higher oil and natural gas commodity prices. For the year ended December 31, 2013, Energen Resources earned $146.8 million, as compared with $204.1 million in the previous year. Alabama Gas Corporation (Alagasco), Energen’s utility subsidiary, generated net income of $57.4 million in the current year, which includes an after-tax gain of $6.8 million on the sale of the Metro Operations Center, as compared with net income in the prior period of $49.4 million. For the year ended December 31, 2011, Energen reported net income of $259.6 million, or $3.59 per diluted share.

2013 vs 2012: Energen Resources’ net income totaled $146.8 million in 2013 as compared with $204.1 million in 2012. Energen Resources’ income from continuing operations totaled $135.3 million in 2013 as compared with $205.7 million in 2012. Income from discontinued operations for the current year was $11.4 million, as compared with a loss of $1.7 million from the prior year. Income from discontinued operations in 2013 included an after-tax gain of $22.5 million on the sale of the Black Warrior Basin coalbed methane properties partially offset by the non-cash impairment writedown on North Louisiana/East Texas natural gas and oil properties of $18.9 million after-tax. Loss from discontinued operations in 2012 included a non-cash impairment on certain properties in East Texas of approximately $13.4 million after-tax. From continuing operations, increased DD&A expense of approximately $73 million after-tax, a year-over-year after-tax $67.8 million non-cash mark-to-market decrease in derivatives (resulting from an after-tax $30.6 million non-cash mark-to-market loss on derivatives for 2013 and an after-tax $37.2 million non-cash mark-to-market gain on derivatives for 2012), higher lease operating expense excluding production taxes of approximately $39 million after-tax, increased administrative expense of approximately $23 million after-tax, increased production taxes of approximately $9 million after-tax, higher exploration expense of approximately $6 million after-tax, lower commodity prices for natural gas liquids of approximately $3 million after-tax, increased interest expense of approximately $3 million after-tax and lower natural gas production volumes of approximately $3 million were partially offset by significantly greater oil and natural gas liquid production volumes of approximately $103 million after-tax and higher oil and natural gas commodity prices of approximately $49 million after-tax.

Alagasco earned net income of $57.4 million in 2013 as compared with net income of $49.4 million in 2012 which primarily reflects the utility’s ability to earn on a higher level of equity in support of Alagasco’s investment in its distribution system and support systems devoted to public service and an after-tax gain of $6.8 million on the sale of the Metro Operations Center.

2012 vs 2011: For the year ended December 31, 2012, Energen Resources’ net income totaled $204.1 million as compared to $213 million in the prior year. Energen Resources’ income from continuing operations totaled $205.7 million in 2012 as compared with $177.5 million in 2011. Loss from discontinued operations for 2012 was $1.7 million, as compared with income of $35.3 million from 2011. Loss from discontinued operations in 2012 included a non-cash impairment on certain properties in East Texas of approximately $13.4 million after-tax. Lower natural gas and natural gas liquids commodity prices of approximately $70 million after-tax, increased DD&A expense of approximately $83 million after-tax, higher lease operating expense of approximately $32 million after-tax, increased interest expense of approximately $12 million after-tax, higher exploration expense of approximately $4 million after-tax, the 2011 after-tax gain of $3.6 million on the sale of certain oil properties were partially offset by increased production volumes of approximately $153 million after-tax, a year-over-year after-tax $60.6 million non-cash mark-to-market increase in derivatives (resulting from an after-tax $37.2 million non-cash mark-to-market gain on derivatives for 2012 and an after-tax $23.4 million non-cash mark-to-market loss on derivatives for 2011) and higher oil commodity prices of approximately $20 million after-tax.

Alagasco’s net income of $49.4 million in 2012 compared to net income of $46.6 million in 2011. This increase in earnings largely reflected the utility’s ability to earn on a higher level of equity in support of Alagasco’s investment in its distribution system and support systems devoted to public service.

Operating Income
Consolidated operating income in 2013, 2012 and 2011 totaled $351.2 million, $461.9 million and $393.7 million, respectively. Lower operating income for 2013 is primarily due to higher DD&A, higher lease operating expense and the non-cash mark-to-market decrease in derivatives partially offset by increased oil and natural gas liquids production and higher natural gas and oil commodity prices at Energen Resources. Growth in operating income for 2012 was influenced by increased production and higher oil commodity prices partially offset by lower natural gas and natural gas liquids commodity prices. During 2013 and 2012, Alagasco contributed to operating income consistent with the level of equity supporting the investment in its distribution system and support systems devoted to public service.

Oil and Gas Operations: Revenues from continuing oil and gas operations increased in the current year largely as a result of significantly higher oil and natural gas liquids production volumes and higher realized oil and natural gas commodity prices partially offset by the non-cash mark-to-market decrease in derivatives combined with lower natural gas liquids commodity prices and decreased natural gas production volumes. Production increased due to higher volumes related to increased field development in certain Permian Basin liquids-rich properties partially offset by normal production declines. Revenue per unit of production for natural gas production rose 14.5 percent to $4.19 per thousand cubic feet (Mcf), oil revenue per unit of production increased 5 percent to $87.65 per barrel and natural gas liquids revenue per unit of production fell 5.1 percent to $0.75 per gallon during 2013. Production from continuing operations rose 9.9 percent to 23.3 MMBOE during 2013. Natural gas production decreased 1.8 percent to 58.1 billion cubic feet (Bcf) while oil volumes rose 18.5 percent to 10,364 thousand barrels (MBbl). Production of natural gas liquids increased 25.6 percent to 135.8 million gallons (MMgal). Revenues per unit of production include realized prices and the effects of designated cash flow hedges and exclude the impact of the non-cash mark-to-market hedges.

In 2012, revenues from continuing oil and gas operations increased largely as a result of higher production volumes and higher oil commodity prices partially offset by lower natural gas and natural gas liquids commodity prices. Production increased due to higher volumes related to increased field development in certain Permian Basin properties and increased volumes related to acquisitions of certain Permian Basin properties partially offset by normal production declines. During 2012, revenue per unit of production for natural gas production fell 29.6 percent to $3.66 per Mcf, oil revenue per unit of production rose 4.5 percent to $83.46 per barrel and natural gas liquids revenue per unit of production decreased 17.7 percent to $0.79 per gallon. Production from continuing operations rose 21.1 percent to 21.2 MMBOE during 2012. Natural gas production increased 9.3 percent to 59.2 Bcf and oil volumes rose 38.9 percent to 8,749 MBbl. Production of natural gas liquids increased 18.3 percent to 108.1 MMgal.

Years ended December 31, (in thousands, except sales price data)	2013	2012	2011
Operating revenues from continuing operations			
Natural gas	$239,643	$216,073	$281,501
Oil	865,100	788,937	465,735
Natural gas liquids	101,550	85,938	87,464
Other	(981)	(1,718)	3,460
Total operating revenues	$1,205,312	$1,089,230	$838,160
Non-cash mark-to-market gains (losses) (included in operating revenues above)			
Natural gas	$(3,919)	$(515)	$—
Oil	(43,261)	58,786	(37,473)
Natural gas liquids	(652)	479	(114)
Total	$(47,832)	$58,750	$(37,587)
Production volumes from continuing operations			
Natural gas (MMcf)	58,104	59,166	54,132
Oil (MBbl)	10,364	8,749	6,300
Natural gas liquids (MMgal)	135.8	108.1	91.4
Total production volumes from continuing operations (MBOE)	23,281	21,183	17,499

Production volumes			
Natural gas (MMcf)	70,506	76,362	71,718
Oil (MBbl)	10,378	8,766	6,318
Natural gas liquids (MMgal)	135.8	108.1	91.4

Total production volumes (MBOE)	25,362	24,066	20,448
San Juan Basin - Basin Field production volumes (included in production volumes above)*			
Natural gas (MMcf)	29,453	34,595	33,656
Oil (MBbl)	13	12	13
Natural gas liquids (MMgal)	22.7	24.2	25.2
Total production volumes (MBOE)	5,462	6,354	6,223
Permian Basin - Spraberry (Trend Area) Field production volumes (included in production volumes above)**			
Natural gas (MMcf)	4,836	3,592	1,650
Oil (MBbl)	2,822	2,134	1,136
Natural gas liquids (MMgal)	38.5	25.8	14.7
Total production volumes (MBOE)	4,544	3,347	1,762
Revenue per unit of production excluding effects of non-cash mark-to-market derivative instruments			
Natural gas (per Mcf)	$4.19	$3.66	$5.20
Oil (per barrel)	$87.65	$83.46	$79.87
Natural gas liquids (per gallon)	$0.75	$0.79	$0.96
Revenue per unit of production excluding effects of all derivative instruments			
Natural gas (per Mcf)	$3.51	$2.69	$3.89
Oil (per barrel)	$92.73	$87.56	$90.54
Natural gas liquids (per gallon)	$0.67	$0.75	$1.11
Average production (lifting) cost (per BOE) (excludes ad valorem tax)	$11.06	$9.55	$9.11
Average ad valorem tax (per BOE)	$1.14	$1.05	$0.88
Average production tax (per BOE)	$2.90	$2.53	$2.95
Average DD&A rate (per BOE)	$19.32	$16.03	$12.03

* The Basin Field in the San Juan Basin contained 15 percent or more of the Company’s total proved reserves as of December 31, 2013.
** The Spraberry (Trend Area) Field in the Permian Basin contained 15 percent or more of the Company’s total proved reserves as of December 31, 2013.

Operations and maintenance (O&M) expense rose $103 million in 2013 and increased $57.7 million in 2012. Lease operating expense (excluding production taxes) generally reflects year over year increases in the number of active wells resulting from Energen Resources’ ongoing development, exploratory and acquisition activities. During 2013, lease operating expense (excluding production taxes) increased $59.6 million largely due to additional workover and repair expense (approximately $26.5 million), increased equipment rental expense (approximately $4.5 million), increased marketing and transportation costs (approximately $4.3 million), higher gathering costs (approximately $4.2 million), higher ad valorem taxes (approximately $4 million), higher labor costs (approximately $3.6 million), increased environmental compliance costs (approximately $3.1 million), additional electrical costs (approximately $2.8 million), increased chemical usage (approximately $2.4 million) and increased nonoperated costs (approximately $2.4 million). In 2012, lease operating expense (excluding production taxes) increased $49.7 million largely due to increased water disposal costs (approximately $15.2 million), higher workover and repair expense (approximately $9.3 million), higher ad valorem taxes (approximately $6.5 million), the Permian Basin property acquisitions (approximately $5 million), additional equipment rental expense (approximately $3.5 million), increased marketing and transportation costs (approximately $3.2 million), increased chemical and treatment costs (approximately $2.7 million), additional electrical costs (approximately $2 million), increased nonoperated costs (approximately $1.7 million), increased labor costs (approximately $1.4 million) and higher environmental compliance expense (approximately $1.1 million) partially offset by decreased other O&M expense (approximately $3.6 million). On a per unit basis, the average lease operating expense (excluding production taxes) for 2013 was $12.20 per barrel of oil equivalent (BOE) as compared to $10.60 per BOE in the same period a year ago. In 2013, administrative expense rose $34.9 million primarily due to increased costs related to the Company’s benefit and performance-based compensation plans (approximately $21.7 million), higher labor costs (approximately $7.4 million), increased legal expenses (approximately $3 million) and higher professional services (approximately $1.1 million). Administrative expense rose $1.6 million in 2012 largely due to increased labor costs (approximately $4.3 million) partially offset by decreased costs from the Company's benefit and performance-based compensation plans (approximately $1.8 million). Exploration expense increased $8.6 million in 2013 largely due to the expected expiration of certain leasehold acreage. Exploration expense rose $6.4 million during 2012 primarily due to charges incurred of $5.3 million for unproved capitalized leasehold costs.

DD&A expense increased $110.3 million in 2013 and $129.3 million in 2012. The average DD&A rates were $19.32 per BOE in 2013, $16.03 per BOE in 2012 and $12.03 per BOE in 2011. The increase in the 2013 and 2012 per unit DD&A rates, which contributed approximately $76.6 million and $84.7 million, respectively, to the increase in DD&A expense, was primarily due to higher rates resulting from an increase in development costs. Increased production volumes also contributed approximately $33.6 million and $44.3 million to the increase in DD&A expense in 2013 and 2012, respectively.

Energen Resources' expense for taxes other than income taxes primarily reflected production-related taxes. Energen Resources recorded severance taxes of $67.5 million, $53.7 million and $51.6 million for 2013, 2012 and 2011, respectively. In 2013, severance taxes were $13.8 million higher resulting from increased oil and natural gas commodity market prices and higher oil and natural gas liquids production volumes. Higher commodity market prices and the impact of increased production volumes contributed approximately $8.5 million and $5.3 million to the increase in severance taxes, respectively. Severance taxes were $2.1 million higher in 2012 resulting from higher production volumes largely offset by lower commodity market prices. Increased production volumes contributed approximately $10.9 million to the increase in severance taxes while decreased commodity market prices lowered severance taxes by approximately $8.8 million. Commodity market prices exclude the effects of derivative instruments for purposes of determining severance taxes.

Natural Gas Distribution: As discussed more fully in Note 2, Regulatory Matters, in the Notes to Financial Statements, Alagasco is subject to regulation by the Alabama Public Service Commission (APSC) and was allowed to earn a range of return of 13.15 percent to 13.65 percent on average equity through December 31, 2013. Rate Stabilization and Equalization (RSE) limited the utility's equity upon which a return is permitted to 55 percent of total capitalization, subject to certain adjustments. Alagasco's original RSE order had a term extending through December 31, 2014. On December 20, 2013, the APSC issued a final written order modifying RSE effective January 1, 2014 as follows. The term will continue beyond September 30, 2018, unless the APSC enters an order to the contrary in a manner consistent with law. In the event of unforeseen circumstances, whether physical or economic, of the nature of force majeure and including a change in control the APSC and Alagasco will consult in good faith with respect to modifications, if any. Alagasco's allowed range of return on average common equity will be 10.5 percent to 10.95 percent with an adjusting point of 10.8 percent. Alagasco is eligible to receive a performance-based adjustment of 5 basis points to the return on equity adjusting point, based on meeting certain customer satisfaction criteria. The equity upon which a return will be permitted cannot exceed 56.5 percent of total capitalization, subject to certain adjustments. The inflation-based Cost Control Mechanism (CCM) will be adjusted to allow annual increases to O&M expense using the June Consumer Price Index For All Urban Consumers (Index Range) each rate year plus or minus 1.75 percent and from 2007 actual expenses, adjusted for inflation using the Index Range. Given existing economic conditions, Alagasco expects only modest growth in equity as annual dividends are typically paid by the utility.

Alagasco generates revenues through the sale and transportation of natural gas. The transportation rate does not contain an amount representing the cost of gas, and Alagasco's rate structure allows similar margins on transportation and sales gas. Weather can cause variations in space heating revenues; as such, Alagasco's tariff provides a temperature adjustment mechanism that is designed to moderate the impact of departures from normal temperatures on Alagasco's earnings. The temperature adjustment applies primarily to residential, small commercial and small industrial customers and is adjusted through the Gas Supply Adjustment (GSA) rider. Other non-temperature weather related conditions that may affect customer usage are not included in the temperature adjustment.

Alagasco's natural gas and transportation sales revenues totaled $533.3 million, $451.6 million and $535.0 million in 2013, 2012 and 2011, respectively. Sales revenue in 2013 rose primarily due to an increase in gas cost of approximately $37 million along with an increase in customer usage of approximately $36 million. In 2013, Alagasco had a net reduction in revenues of $10.6 million pre-tax to bring the return on average equity to midpoint within the allowed range of return. During the year ended December 31, 2012, Alagasco had a net reduction in revenues of $6.3 million pre-tax to bring the return on average equity to midpoint within the allowed range of return. In 2013, weather that was 38.4 percent colder than in the prior year contributed to a 26.6 percent increase in residential sales volumes and a 19.1 percent increase in commercial and industrial volumes. Transportation volumes fell 1.2 percent. In 2012, sales revenue declined largely due to decreased customer usage of approximately $53 million and a decline in gas cost of approximately $38 million. Alagasco had a net reduction in revenues of $6.3 million pre-tax in 2012, as discussed above. During the year ended December 31, 2011, Alagasco had a net reduction in revenues of $6.7 million pre-tax to bring the return on average equity to midpoint within the allowed range of return. Weather was 27.1 percent warmer in 2012 than in the prior year. Residential sales volumes declined 24.2 percent while commercial and industrial volumes decreased 16.2 percent. Transportation volumes increased 7.8 percent. In 2013, higher gas costs along with increased gas purchase volumes contributed to a 51.5 percent increase in cost of gas. A significant decrease in gas purchase volumes combined with a decrease in gas costs resulted in a 39.1 percent decrease in cost of gas in 2012.

O&M expense at the utility rose 1.3 percent in 2013 largely due to increased labor-related costs (approximately $3.5 million) and increased bad debt expense (approximately $0.6 million) partially offset by decreased consulting and technology costs (approximately $1 million). O&M expense at the utility rose 1.7 percent in 2012 largely due to higher business development and marketing expense (approximately $1.9 million), increased distribution operations (approximately $0.8 million), additional technology costs (approximately $0.6 million) and increased legal expense (approximately $0.4 million) partially offset by decreased bad debt expense (approximately $2.3 million) impacted by warmer weather in the current year and enhanced credit and collection processes implemented in 2011. Alagasco's O&M expense fell within the Index Range for the rate years ended September 30, 2013, 2012 and 2011.

Depreciation expense increased 3.9 percent and 5.9 percent in 2013 and 2012, respectively, largely due to the extension and replacement of the utility's distribution system and replacement of its support systems. Approved depreciation rates averaged approximately 3.1 percent, 3.2 percent and 3.1 percent in the years ended December 31, 2013, 2012 and 2011, respectively.

Alagasco's expense for taxes other than income primarily reflects various state and local business taxes as well as payroll-related taxes. State and local business taxes generally are based on gross receipts and fluctuate accordingly.

Years ended December 31, (in thousands)	2013	2012	2011
Natural gas transportation and sales revenues	$533,338	$451,589	$534,953
Cost of gas	(215,455)	(142,228)	(233,523)
Operations and maintenance	(143,138)	(141,334)	(139,030)
Depreciation and amortization	(43,907)	(42,270)	(39,916)
Income taxes	(34,687)	(30,244)	(26,670)
Taxes, other than income taxes	(37,070)	(32,541)	(36,268)
Operating income	$59,081	$62,972	$59,546
Natural gas sales volumes (MMcf)			
Residential	20,279	16,014	21,132
Commercial and industrial	9,968	8,372	9,994
Total natural gas sales volumes	30,247	24,386	31,126
Natural gas transportation volumes (MMcf)	47,534	48,106	44,614
Total deliveries (MMcf)	77,781	72,492	75,740

Non-Operating Items

Consolidated: Interest expense rose $3.7 million in 2013 largely due to higher short-term borrowings and the December 2013, issuance of $600 million in Senior Term Loans with a floating interest rate due March 31, 2014 through December 17, 2017. The $600 million issuance includes $400 million with a floating rate of LIBOR plus 1.625 percent, currently 1.792 percent at December 31, 2013 and $200 million swapped to a fixed rate at 2.6675 percent. These increases in interest expense for 2013 were partially offset by the October 2013 repayment of $50 million of 5 percent Notes and the December 2013 repayment of the Senior Term Loans of $300 million issued in November 2011. In 2012, interest expense increased $20.7 million primarily due to the August 2011 issuance of $400 million of Senior Notes by Energen with an interest rate of 4.625 percent, the December 2011 issuance of $50 million of Senior Notes by Alagasco with an interest rate of 3.86 percent and the November 2011 issuance of $300 million of Senior Term Loans. The $300 million issuance included $100 million with a floating rate of LIBOR plus 1.375 percent and $200 million swapped to a fixed rate at 2.4175 percent. Higher short-term borrowings also contributed to the increase in interest expense for 2012. The average daily outstanding balance under credit facilities was $804.9 million in 2013. The average daily outstanding balance under credit facilities was $331.1 million in 2012 as compared to $229.1 million in 2011. Other income for the Company increased $12.5 million in 2013 primarily due to the pre-tax gain of $10.9 million on the August 2013 sale of Alagasco's Metro Operations Center. Income tax expense decreased in 2013 largely due to lower pre-tax income while income tax expense increased in 2012 primarily due to higher pre-tax income.

FINANCIAL POSITION AND LIQUIDITY

The Company's net cash from operating activities totaled $927.4 million, $735.7 million and $761.8 million in 2013, 2012 and 2011, respectively. During 2013, operating cash flows increased due to an increase in oil and natural gas liquids production and higher natural gas and oil commodity prices at Energen Resources. Net income in 2013 was also significantly impacted by non-cash charges, including higher DD&A, the change in derivative fair value and a gain on the sale of certain assets. The Company's working capital needs were also influenced by accrued taxes along with commodity prices, and the timing of payments and recoveries, including gas supply pass-through adjustments. Net income decreased during 2012 largely due to lower realized natural gas and natural gas liquids commodity prices partially offset by increased production volumes at Energen Resources and higher oil commodity prices. During 2011, net income decreased largely due to lower realized natural gas commodity prices partially offset by increased production volumes at Energen Resources and higher oil and natural gas liquids commodity prices. During 2011, the income tax receivable decreased approximately $37.1 million primarily from an income tax refund associated with the 2010 impact of bonus depreciation and the write-off of Alabama shale leasehold. Working capital needs during 2013, 2012 and 2011 at Alagasco were largely affected by gas costs, accrued taxes and storage gas inventory. Other working capital items, which primarily are the result of changes in throughput and the timing of payments and recoveries, including gas supply pass-through adjustments and refundable negative salvage costs, combined to create the remaining increases in all years.

The Company made net investments of $1,053.6 million during 2013. Energen Resources invested $31.3 million in property acquisitions including approximately $26.8 million of unproved leaseholds; $675.4 million for development costs (excludes the reversal of approximately $23.9 million of accrued development cost) including approximately $457 million to drill 179 net development and service wells; and $423.7 million for exploration including approximately $295 million to drill 90 net exploratory wells. Energen Resources had cash proceeds in 2013 of $161 million primarily from the sale of certain Black Warrior Basin properties. Utility expenditures in 2013 totaled $86.0 million (excludes approximately $2 million of accrued capital cost) and primarily represented expansion and replacement of its distribution system and replacement of its support facilities and information systems. Alagasco had cash proceeds in 2013 of $13.8 million from the sale of its Metro Operations Center. During 2012, the Company made net investments of $1,322.2 million. Energen Resources invested $139.6 million in property acquisitions including approximately $58.6 million of unproved leaseholds; $692.4 million for development costs (excludes the reversal of approximately $46.8 million of accrued development cost) including approximately $560 million to drill 288 net development and service wells; and $416.7 million for exploration including approximately $376.6 million to drill 75 net exploratory wells. In February 2012, Energen completed the purchase of certain properties in the Permian Basin for a cash purchase price of $68 million adding approximately 8.2 MMBOE of proved reserves. Energen Resources had cash proceeds in 2012 of $3 million primarily from the sale of certain Black Warrior Basin properties. Utility expenditures in 2012 totaled $69.9 million (excludes approximately $1.3 million of accrued capital cost). During 2011, the Company made net investments of $1,193.5 million. Energen Resources invested $310.2 million in property acquisitions including approximately $91.9 million of unproved leaseholds; $618 million for development costs (excludes the reversal of approximately $1 million of accrued development cost) including approximately $520 million to drill 403 net development and service wells; and $188.7 million for exploration including approximately $178.8 million to drill 24 net exploratory wells. In November 2011, Energen Resources completed a purchase of liquids-rich properties located in the Permian Basin for a cash price of approximately $162 million adding approximately 13.6 MMBOE in proved reserves. Energen Resources completed, in December 2011, a purchase of oil properties located in the Permian Basin for a cash price of approximately $60 million. The acquisition added approximately 3.4 MMBOE in proved reserves. Energen Resources had cash proceeds in 2011 of $8 million primarily from the sale of certain Permian and Black Warrior basin properties. Utility expenditures in 2011 totaled $73.4 million (includes approximately $0.4 million of accrued capital cost).

During 2013, Energen Resources added 37 MMBOE of proved reserves from discoveries and other additions, primarily the result of development and exploratory drilling that increased the number of proved undeveloped locations in the Permian Basin. Also during 2013, the Company added approximately 0.2 MMBOE of proved reserves primarily from Permian Basin oil property acquisitions. Energen Resources added approximately 69 MMBOE and 66 MMBOE of proved reserves in 2012 and 2011, respectively.

The Company provided $122.1 million from net financing activities in 2013 largely from the December 2013 issuance of $600 million of Senior Term Loans with a floating interest rate partially offset the repayment of long-term debt of $350.1 million combined with a decrease in short-term borrowings. In 2012, the Company provided $586.6 million from net financing activities largely from an increase in short-term borrowings used to fund development activity at Energen Resources. In 2011, the Company provided $418.6 million from net financing activities largely from the August 2011 issuance of $400 million of Senior Notes by Energen with an interest rate of 4.625 percent, the December 2011 issuance of $50 million of Senior Notes by Alagasco with an interest rate of 3.86 percent and the November 2011 issuance of $300 million of Senior Term Loans with a floating interest rate, partially offset by a decrease in short-term debt borrowings. In addition, long-term debt was reduced by $1.2 million and $5.5 million for current maturities in 2012 and 2011, respectively. For each of the years, net cash used in financing activities also reflected dividends paid to common shareholders which were partially offset by the issuance of common stock through the Company’s stock-based compensation plan.

Capital Expenditures
Oil and Gas Operations: Capital projects at Energen Resources are detailed below. The expanded exploratory expenditures are the result of our activities following the acquisitions of significant unproved leasehold in the Permian Basin in 2012 and 2011.

Years ended December 31, (in thousands)	2013	2012	2011
Capital and exploration expenditures for:			
Property acquisitions	$31,481	$138,496	$306,881
Development	654,222	748,251	621,550
Exploration	423,698	416,678	188,660
Other	11,352	4,543	9,277
Total	1,120,753	1,307,968	1,126,368
Less exploration expenditures charged to income	16,008	16,757	10,916
Net capital expenditures	$1,104,745	$1,291,211	$1,115,452

Natural Gas Distribution: Capital projects at Alagasco are detailed below.

Years ended December 31, (in thousands)	2013	2012	2011
Capital expenditures for:			
Renewals, replacements, system expansion and other	$59,750	$50,075	$53,970
Support systems and facilities	29,019	21,794	20,014
Total	$88,769	$71,869	$73,984

FUTURE CAPITAL RESOURCES AND LIQUIDITY
Oil and Gas Operations
The Company plans to continue investing significant capital in Energen Resources' oil and gas production operations. For 2014, the Company expects its oil and gas capital spending to total approximately $1.05 billion, including $780 million for existing properties and $265 million for exploration. Included in this $780 million is approximately $306 million for the development of previously identified proved undeveloped reserves.

Capital expenditures by area during 2014 are planned as follows:

Year ended December 31, (in thousands)	2014
Permian Basin development	$765,000
Permian Basin exploration	265,000
San Juan Basin	15,000
Other	5,000
Total	$1,050,000

Energen anticipates having the following drilling rigs and net wells by area during 2014. The drilling rigs presented below are operated while the net wells include operated and non-operated wells.

	Drilling Rigs	Net Wells
Permian Basin	14	161

The Company also may allocate additional capital for other oil and gas activities such as property acquisitions and additional development of existing properties. Energen Resources may evaluate acquisition opportunities which arise in the marketplace.

Energen Resources' ability to invest in property acquisitions is subject to market conditions and industry trends. Property acquisitions are not included in the aforementioned estimate of oil and gas investments and could result in capital expenditures different from those outlined above. To finance capital spending at Energen Resources, the Company expects to use internally generated cash flow supplemented by its credit facilities. The Company also may issue long-term debt and equity periodically to replace short-term obligations, enhance liquidity and provide for permanent financing. The Company currently has no plans for the issuance of equity.

Discontinued Operations
In October 2013, Energen Resources completed the sale of its Black Warrior Basin coalbed methane properties in Alabama for $160 million (subject to closing adjustments). The Company recorded a pre-tax gain on the sale of approximately $35 million in the fourth quarter of 2013. The sale had an effective date of July 1, 2013, and the proceeds from the sale were used to repay short-term obligations. The property was classified as held-for-sale and reflected in discontinued operations during the third quarter of 2013. At December 31, 2012, proved reserves associated with Energen's Black Warrior Basin properties totaled 97 Bcf of natural gas.

In January 2014, Energen Resources signed a purchase and sale agreement on its North Louisiana/East Texas natural gas and oil properties for $31.5 million (subject to closing adjustments). The Company expects to complete the sale in the first quarter of 2014 and will use the proceeds to repay short-term obligations. During the third quarter of 2013, Energen Resources classified these natural gas and oil properties as held-for-sale and reflected the associated operating results in discontinued operations. Energen Resources recognized a non-cash impairment writedown on these properties in the third and fourth quarters of $24.6 million pre-tax and $5.2 million pre-tax, respectively, to adjust the carrying amount of these properties to their fair value based on an estimate of the selling price of the properties. The non-cash impairment writedowns are reflected in gain on disposal of discontinued operations in the year ended December 31, 2013. At December 31, 2013, proved reserves associated with Energen's North Louisiana/East Texas properties totaled 23 Bcf of natural gas and 91 MBbl of oil.

During the first quarter of 2012, Energen Resources recognized a non-cash impairment writedown on certain properties in East Texas of $21.5 million pre-tax to adjust the carrying amount of these properties to their fair value based on expected future discounted cash flows. This non-cash impairment writedown is reflected in loss from discontinued operations for the year ended December 31, 2012. The impairment was caused by the impact of lower future natural gas prices. This impairment writedown is classified as Level 3 fair value.

Natural Gas Distribution
Alagasco's rate schedules for natural gas distribution charges contain a GSA rider which permits the pass-through to customers for changes in the cost of gas supply. The GSA rider is designed to capture the Company's cost of natural gas and provides for a pass-through of gas cost fluctuations to customers without markup; the cost of gas includes the commodity cost, pipeline capacity, transportation and fuel costs, and risk management realized gains and losses.

Alagasco is a mature utility operating in a slow-growth service area which includes municipalities that have in recent years experienced population declines. Alagasco's average customer count for 2013 declined approximately 0.6 percent from 2012 and reflected a moderation in decline over the five-year trend. Other factors impacting Alagasco's average customer count include recent weather trends, enhanced credit and collection efforts and the loss of customers due to a 2011 weather event. Alagasco monitors the bad debt reserve and makes adjustments as required based on its evaluation of receivables which are impacted by natural gas prices, weather conditions and the underlying current and future economic conditions facing the utility's customer base. During the year ended December 31, 2013, Alagasco reduced the bad debt reserve by approximately $0.7 million primarily due to certain aged receivables transitioned to the utility's long-term collections, in addition to the impact of its collection related initiatives.

Alagasco maintains an investment in storage gas that is expected to average approximately $28 million in 2014 but will vary depending upon the price of natural gas. During 2014, Alagasco plans to invest approximately $74 million in capital expenditures for the normal needs of its distribution, support systems and technology-related projects designed to improve customer service and the construction of two service centers to replace the Metro Operations Center sold during 2013. The utility anticipates funding these capital requirements through internally generated capital and the utilization of its credit facilities. Alagasco also may issue long-term debt periodically to replace short-term obligations, enhance liquidity and provide for permanent financing.

In August 2013, Alagasco recorded a pre-tax gain of $10.9 million related to the sale of its Metro Operations Center which is located in Birmingham, Alabama, and has been in service since the 1940’s. The Company received approximately $13.8 million pre-tax in cash from the sale of this property. During the third quarter of 2013, the gain on the sale was recognized in other income and a related reduction in revenues was recognized to defer the gain as a regulatory liability pending review by the APSC. In conjunction with the receipt of the rate order from the APSC on December 20, 2013, Alagasco recognized the deferred revenues from this sale in the fourth quarter of 2013. Effective upon the sale of the Metro Operations Center, Alagasco leased the facility from the purchaser for a period of approximately 20 months.

Credit Facilities and Working Capital
Access to capital is an integral part of the Company's business plan. While the Company expects to have ongoing access to its credit facilities and the longer-term markets, continued access could be adversely affected by current and future economic and business conditions and credit rating downgrades. On October 30, 2012, Energen and Alagasco entered into $1.25 billion and $100 million, respectively, five-year syndicated unsecured credit facilities (syndicated credit facilities) with domestic and foreign lenders. Energen's obligations under the $1.25 billion syndicated credit facility are unconditionally guaranteed by Energen Resources. There are certain restrictive covenants including a financial covenant with a maximum consolidated debt to capitalization ratio of not more than 65 percent for both the Company and Alagasco. Both the Company and Alagasco were in compliance with the terms of the syndicated credit facilities at December 31, 2013.

At December 31, 2013, the Company reported negative working capital of $682.7 million arising from current liabilities of $1,109.9 million exceeding current assets of $427.2 million. The negative working capital is primarily due to a $628 million increase in borrowings during 2012 partially offset by a $104 million decrease in borrowings during 2013 under the syndicated unsecured credit facilities and in support of Energen's capital projects. Generally Accepted Accounting Principles require classification as short-term for obligations such as these that are subject to the execution of individual notes with maturity dates less than one year. The syndicated unsecured credit facilities were entered into on October 30, 2012 and have a five-year term. Accordingly, the Company believes that it has adequate financing capacity available for its expected liquidity needs.

Working capital of Energen is also influenced by the fair value of the Company's derivative financial instruments associated with future production. Energen's accounts receivable and accounts payable at December 31, 2013 include $17.5 million and $30.3 million, respectively, associated with its derivative financial instruments. Working capital of Alagasco is additionally impacted by the recovery and pass-through of regulatory items and the seasonality of Alagasco's business and reflects an expected pass-through to rate payers of $15.8 million in refundable negative salvage costs representing a reduction in future revenues through lower tariff rates. Energen and Alagasco rely upon cash flows from operations supplemented by its syndicated unsecured credit facilities to fund working capital needs.

Credit Ratings
On April 26, 2013, Moody's Investor Service updated its credit opinion for Energen and Alagasco confirming Energen's senior unsecured credit rating as investment grade with a negative outlook. Alagasco's senior unsecured credit rating was lowered one notch but remains investment grade with a negative outlook. On December 16, 2013, Standard & Poor's lowered its debt ratings for Energen and Alagasco's from investment grade with a stable outlook to investment grade with a negative outlook.

Dividends
Energen expects to pay annual cash dividends of $0.60 per share on the Company's common stock in 2014. The amount and timing of all dividend payments is subject to the discretion of the Board of Directors and is based upon business conditions, results of operations, financial conditions and other factors.

Contractual Cash Obligations and Other Commitments
In the course of ordinary business activities, Energen enters into a variety of contractual cash obligations and other commitments. The following table summarizes the Company's significant contractual cash obligations, other than hedging contracts, as of December 31, 2013:

Payments Due Before December 31,

(in thousands)	Total	2014	2015-2016	2017-2018	2019 and Thereafter
Long-term debt [1]	$1,403,923	$60,000	$200,000	$439,000	$704,923
Interest payments on debt	455,171	54,585	100,763	82,812	217,011
Purchase obligations [2]	171,110	47,810	93,840	26,791	2,669
Operating leases	31,627	5,270	9,331	6,389	10,637
Asset retirement obligations [3]	709,451	11,538	6,162	5,933	685,818
Nonqualified supplemental retirement plans	36,597	6,145	1,112	9,939	19,401
Total contractual cash obligations	$2,807,879	$185,348	$411,208	$570,864	$1,640,459

(1) Long-term cash obligations include approximately $0.5 million of unamortized debt discounts as of December 31, 2013.

(2) Certain of the Company's long-term contracts associated with the delivery and storage of natural gas include fixed charges of approximately $171 million through September 2024. The Company also is committed to purchase minimum quantities of gas at market-related prices or to pay certain costs in the event the minimum quantities are not taken. These purchase commitments are approximately 134 Bcf through August 2020.

(3) Represents the estimated future asset retirement obligation on an undiscounted basis. Energen Resources operates in certain instances through joint ventures under joint operating agreements. Typically, the operator under a joint operating agreement enters into contracts, such as drilling contracts, for the benefit of all joint venture partners. Through the joint operating agreement, the non-operators reimburse, and in some cases advance, the funds necessary to meet the contractual obligations entered into by the operator. These obligations are typically shared on a working interest basis as defined in the joint operating contractual agreement.

Under various agreements for third party gathering, treatment, transportation or other services, Energen Resources is committed to deliver minimum production volumes or to pay certain costs in the event the minimum quantities are not delivered. These delivery commitments are approximately 7.1 MMBOE through September 2017.

Energen Resources entered into an agreement which commenced on January 15, 2012 and expires in January 2015 to secure a drilling rig necessary to execute a portion of its drilling plans. In the unlikely event that Energen Resources discontinues use of this drilling rig, Energen Resources' total resulting exposure could be as much as $3.9 million depending on the contractor's ability to remarket the drilling rig.

There are no required contributions to the qualified pension plans during 2014. Additionally, it is not anticipated that the funded status of the qualified pension plans will fall below statutory thresholds requiring accelerated funding or constraints on benefit levels or plan administration. The Company made a discretionary contribution of $3 million to the qualified pension plans in January 2014. During 2014, the Company may make additional discretionary contributions to the qualified pension plans depending on the amount and timing of employee retirements and market conditions. The contractual obligations reported above exclude any payments the Company expects to make to postretirement benefit program assets.

The contractual obligations reported above exclude the Company's liability of $16.0 million related to the Company's provision for uncertain tax positions. The Company cannot make a reasonably reliable estimate of the amount and period of related future payments for such liability.

During the third quarter of 2010, Energen Resources received preliminary findings from the Taxation and Revenue Department (the Department) of the State of New Mexico relating to its audit, conducted on behalf of the Office of Natural Resources Revenue (ONRR), of federal oil and gas leases in New Mexico. The audit covered periods from January 2004 through December 2008 and included a review of the computation and payment of royalties due on minerals removed from specified U.S. federal leases. The ONRR has proposed certain changes in the method of determining allowable deductions of transportation, fuel and processing costs from royalties due under the terms of the related leases.

As a result of the audit, Energen Resources has been ordered by the ONRR to pay additional royalties on the specified U.S. federal leases in the amount of $142,000 and restructure its accounting for all federal leases in two counties in New Mexico from March 1, 2004, forward. The Company preliminarily estimates that application of the Order to all of the Company's New Mexico federal leases would result in ONRR claims for up to approximately $23 million of additional royalties plus interest and penalties for the period from March 1, 2004, forward. The preliminary findings and subsequent Order (issued April 25, 2011) are contrary to deductions allowed under previous audits, retroactive in application and inconsistent with the Company's understanding of industry practice. The Company is vigorously contesting the Order and has requested additional information from the ONRR and the Department to assist the Company in evaluating the ONRR Order and the Department's findings. Management is unable, at this time, to determine a range of reasonably possible losses as a result of this Order, and no amount has been accrued as of December 31, 2013.

OUTLOOK

Oil and Gas Operations: Energen Resources plans to continue to implement its growth strategy with capital spending in 2014. Production in 2014 is estimated to range from 24.4 MMBOE to 25.4 MMBOE, with a midpoint of 24.9 MMBOE, including approximately 22.1 MMBOE of estimated production from proved reserves owned at December 31, 2013. Production estimates do not include amounts for potential future acquisitions. In the event Energen Resources is unable to fully invest in its capital investment opportunities, future operating revenues, production and proved reserves could be negatively affected.

Production volumes by area are expected to be as follows:

Year ended December 31, (MMBOE)	2014
Permian Basin	16.5
San Juan Basin/other	8.4
Total (midpoint of range)	24.9

Production volumes by commodity are expected to be as follows:

Year ended December 31, (MMBOE)	2014
Gas	9.7
Oil	11.4
Natural gas liquids	3.8
Total (midpoint of range)	24.9

During 2014, Energen Resources expects an annualized decline rate of approximately14 percent for its proved developed producing properties owned at December 31, 2013. During the same period, total production from proved properties is expected to decrease approximately 5 percent and total production is expected to increase approximately 6.7 percent. The above proved developed producing properties decline rate is not necessarily indicative of the Company's expectations for its terminal decline rate on a long-term basis.

Various factors influence decline rates. For example, certain properties may have production curves that decline at faster rates in the early years of production and at slower rates in later years. Accordingly, the decline rate for a single year is influenced by numerous factors, including but not limited to, the mix of types of wells, the mix of newer versus older wells, and the effect of enhanced recovery activities, but it is not necessarily indicative of future decline rates. Energen Resources expects a compound annual decline rate for proved producing properties owned at December 31, 2013 for the 5 year period 2013 to 2018, for the 10 year period 2013 to 2023 and for the 20 year period 2013 to 2033 of approximately 13.2 percent, 10.6 percent and 8.7 percent, respectively.

Energen Resources' major market risk exposure is in the pricing applicable to its oil and gas production. Historically, prices received for oil and gas production have been volatile because of seasonal weather patterns, national supply and demand factors and general economic conditions. Crude oil prices also are affected by quality differentials, worldwide political developments and actions of the Organization of the Petroleum Exporting Countries. Basis differentials, like the underlying commodity prices, can be volatile because of regional supply and demand factors, including seasonal variations and the availability and price of transportation to consuming areas. Additionally, downward commodity price trends may impact expected cash flows from future production and potentially reduce the carrying value of Company-owned oil and natural gas properties.

Revenues and related accounts receivable from oil and gas operations primarily are generated from the sale of produced oil, natural gas and natural gas liquids to energy marketing companies. Such sales are typically made on an unsecured credit basis with payment due the month following delivery. This concentration of sales to the energy marketing industry has the potential to affect the Company's overall exposure to credit risk, either positively or negatively, in that the Company's oil and gas purchasers may be affected similarly by changes in economic, industry or other conditions. Energen Resources considers the credit quality of its customers and, in certain instances, may require credit assurances such as a deposit, letter of credit or parent guarantee.

Derivative Commodity Instruments
Energen Resources periodically enters into derivative commodity instruments to hedge its exposure to price fluctuations on oil, natural gas and natural gas liquids production. Such instruments may include natural gas and crude

oil over-the-counter (OTC) swaps and basis hedges typically with investment and commercial banks and energy-trading firms. At December 31, 2013, the counterparty agreements under which the Company had active positions did not include collateral posting requirements. Energen Resources was in a net gain position with seven of its active counterparties and in a net loss position with the remaining six at December 31, 2013. The Company is at risk for economic loss based upon the creditworthiness of its counterparties. Hedge transactions are pursuant to standing authorizations by the Board of Directors, which do not authorize speculative positions. Energen Resources does not hedge more than 80 percent of its estimated annual production.

In prior years, Alagasco entered into cash flow derivative commodity instruments to hedge its exposure to price fluctuations on its gas supply pursuant to standing authorizations by the Board of Directors. Alagasco has not entered into any cash flow derivative transactions on its gas supply since 2010. Alagasco recognizes all derivatives at fair value as either assets or liabilities on the balance sheet. Any realized gains or losses are passed through to customers using the mechanisms of the GSA rider in accordance with Alagasco's APSC approved tariff and are recognized as a regulatory asset or regulatory liability.

Energen Resources entered into the following transactions for 2014 and subsequent years:

Production Period	Total Hedged Volumes		Average Contract Price	Description
Natural Gas				
2014	10.6	Bcf	$4.55 Mcf	NYMEX Swaps
	31.4	Bcf	$4.60 Mcf	Basin Specific Swaps - San Juan
	9.7	Bcf	$3.81 Mcf	Basin Specific Swaps - Permian
2015	6.0	Bcf	$4.07 Mcf	Basin Specific Swaps - San Juan
Oil				
2014	9,796	MBbl	$92.64 Bbl	NYMEX Swaps
2015	5,760	MBbl	$88.85 Bbl	NYMEX Swaps

Energen Resources has prepared a sensitivity analysis to evaluate the hypothetical effect that changes in the market value of crude oil, natural gas and natural gas liquids may have on the fair value of its derivative instruments. This analysis measured the impact on the commodity derivative instruments and, thereby, did not consider the underlying exposure related to the commodity. At December 31, 2013, Energen Resources was in a net loss position of $7.4 million for derivative contracts and estimates that a 10 percent increase or decrease in the commodities prices would have resulted in an approximate $165 million change in the fair value of open derivative contracts; however, gains and losses on derivative contracts are expected to be similarly offset by sales at the spot market price. The hypothetical change in fair value was calculated by multiplying the difference between the hypothetical price and the contractual price by the contractual volumes and did not include the impact of related taxes on actual cash prices.

All derivatives are recognized at fair value under the fair value hierarchy as discussed in Note 1, Summary of Significant Accounting Policies, in the Notes to Financial Statements. Over-the-counter derivatives are valued using market transactions and other market evidence whenever possible, including market-based inputs to models and broker or dealer quotations. These OTC derivative contracts trade in less liquid markets with limited pricing information as compared to markets with actively traded, unadjusted quoted prices; accordingly, the determination of fair value is inherently more difficult. OTC derivatives for which the Company is able to substantiate fair value through directly observable market prices are classified within Level 2 of the fair value hierarchy. These Level 2 fair values consist of swaps priced in reference to New York Mercantile Exchange (NYMEX) natural gas and oil futures. OTC derivatives valued using unobservable market prices have been classified within Level 3 of the fair value hierarchy. These Level 3 fair values include basin specific, basis and natural gas liquids swaps. The Company considers frequency of pricing and variability in pricing between sources in determining whether a market is considered active. While the Company does not have access to the specific assumptions used in its counterparties' valuation models, the Company maintains communications with its counterparties and discusses pricing practices. Further, the Company corroborates the fair value of its transactions by comparison of market-based price sources. All derivative commodity instruments in a gain position are valued on a discounted basis incorporating an estimate of performance risk specific to each related counterparty. Derivative commodity instruments in a loss position are valued on a discounted basis incorporating an estimate of performance risk specific to Energen or Alagasco. As of the balance sheet date, the Company believes that these prices represent the best estimate of the exit price for these instruments and are representative of the prices for which the contract will ultimately settle or realize.

The following sets forth derivative assets and liabilities that were measured at fair value on a recurring basis:

	December 31, 2013		
(in thousands)	Level 2*	Level 3*	Total
Current assets	$(1,658)	$19,121	$17,463
Noncurrent assets	4,383	1,056	5,439
Current liabilities	(28,414)	(1,888)	(30,302)
Net derivative asset (liability)	$(25,689)	$18,289	$(7,400)

	December 31, 2012		
(in thousands)	Level 2*	Level 3*	Total
Current assets	$(3,629)	$68,421	$64,792
Noncurrent assets	18,899	21,678	40,577
Current liabilities	(2,593)	—	(2,593)
Noncurrent liabilities	(8,520)	(1,080)	(9,600)
Net derivative asset	$4,157	$89,019	$93,176

* Amounts classified in accordance with accounting guidance which permits offsetting fair value of amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement.

As of December 31, 2013, Alagasco had no derivative instruments. As of December 31, 2012, Alagasco had $2.6 million of derivative instruments which are classified as Level 2 fair values and are included in the above table as current liabilities. Alagasco had no derivative instruments classified as Level 3 fair values as of December 31, 2012.

Level 3 assets as of December 31, 2013 represent an immaterial amount of both total assets and liabilities. Changes in fair value primarily result from price changes in the underlying commodity. The Company has prepared a sensitivity analysis to evaluate the hypothetical effect that changes in the prices used to estimate fair value would have on the fair value of its derivative instruments. The Company estimates that a 10 percent increase or decrease in commodity prices would result in an approximate $19 million change in the fair value of open Level 3 derivative contracts. The resulting impact upon the results of operations would be an approximate $19 million associated with open Level 3 mark-to-market derivative contracts. Liquidity requirements to meet the obligation would not be significantly impacted as gains and losses on the derivative contracts would be similarly offset by sales at the spot market price.

In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was signed into law. Title VII of the Dodd-Frank Act establishes federal oversight and regulation of the over-the-counter derivatives markets and participants in such markets and requires the Commodities Futures Trading Commission (CFTC) and the Securities and Exchange Commission (SEC) to promulgate implementing rules and regulations. The Dodd-Frank Act imposes certain margin, clearing and trade execution requirements. Energen’s derivative transactions qualify for the end-user exception which exempts them from certain Dodd-Frank Act margin and exchange clearing requirements pursuant to final regulations adopted by the CFTC and SEC and published in the Federal Register on July 19, 2012. However, the Company could experience increased costs and reduced liquidity in the markets as a result of the new rules and regulations, which could reduce hedging opportunities and negatively affect the Company’s revenues and cash flows.

Natural Gas Distribution: The extension of RSE effective January 1, 2014 provides Alagasco the opportunity to continue earning an allowed return on average equity between 10.5 percent to 10.95 percent with an adjusting point of 10.8 percent through September 30, 2018. Alagasco’s rate schedules for natural gas distribution charges contain a GSA rider which permits the pass-through to customers for changes in the cost of gas supply. Also as discussed in Note 2, Regulatory Matters, in the Notes to Financial Statements, the utility’s CCM is based on the rate of inflation. Decreases in residential customers and declines in usage per customer in the residential and small commercial classes, as well as market sensitive load losses from large industrial and commercial customers, will make it more difficult for the utility to earn within its allowed range of return on equity. With the support of the APSC, Alagasco has implemented a variety of programs to help it compete for gas load in all market segments. The Company has been effective in utilizing these programs to deter load loss to competitive fuels.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES
The Company’s consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America. Management has identified the following critical accounting policies in the application of existing accounting standards or in the implementation of new standards that involve significant judgments and estimates by the Company. The application of these accounting policies necessarily requires management’s most subjective or complex judgments regarding estimates and projected outcomes of future events that could have a material impact on the financial statements.

Oil and Gas Operations
Accounting for Oil and Natural Gas Producing Activities and Related Reserves: The Company utilizes the successful efforts method of accounting for its oil and natural gas producing activities. Acquisition and development costs of proved properties are capitalized and amortized on a units-of-production basis over the remaining life of total proved and proved developed reserves. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. The technologies associated with these proved reserve estimates are analysis of well production data, geophysical data, wireline and core data. Accordingly, these estimates do not include probable or possible reserves. Estimated oil and gas reserves are based on currently available reservoir data and are subject to future revision. Estimates of physical quantities of oil and gas reserves have been determined by Company engineers. Independent oil and gas reservoir engineers have audited the estimates of proved reserves of natural gas, crude oil and natural gas liquids attributed to the Company’s net interests in oil and gas properties as of December 31, 2013. The independent reservoir engineers have issued reports covering approximately 98 percent of the Company’s ending proved reserves and in their judgment these estimates were reasonable in the aggregate. The Company’s production of proved undeveloped reserves requires the drilling of development wells and the installation or completion of related infrastructure facilities.

Changes in oil and gas prices, operating costs and expected performance from the properties can result in a revision to the amount of estimated reserves held by the Company. If reserves are revised upward, earnings could be affected due to lower depreciation and depletion expense per unit of production. Likewise, if reserves are revised downward, earnings could be affected due to higher depreciation and depletion expense or due to an immediate writedown of the property’s book value if an impairment is warranted.

The table below reflects an estimated increase in 2014 depreciation, depletion and amortization expense associated with an assumed downward revision in the reported oil and gas reserve amounts at December 31, 2013:

	Percentage Change in Oil & Gas Reserves From Reported Reserves as of December 31, 2013	
(dollars in thousands)	-5%	-10%
Estimated increase in DD&A expense for the year ended December 31, 2014, net of tax	$15,197	$31,912

Exploratory drilling costs are capitalized pending determination of proved reserves. If proved reserves are not discovered, the exploratory drilling costs are expensed. Other exploration costs, including geological and geophysical costs, are expensed as incurred.

Asset Impairments: Oil and gas proved properties periodically are assessed for possible impairment on a field-by-field basis using the estimated undiscounted future cash flows. Impairment losses are recognized when the estimated undiscounted future cash flows are less than the current net book values of the properties in a field. The Company monitors its oil and gas properties as well as the market and business environments in which it operates and makes assessments about events that could result in potential impairment issues. Such potential events may include, but are not limited to, substantial commodity price declines, unanticipated increased operating costs, and lower than expected production performance. If a material event occurs, Energen Resources makes an estimate of undiscounted future cash flows to determine whether the asset is impaired. If the asset is impaired, the Company will record an impairment loss for the difference between the net book value of the properties and the fair value of the properties. The fair value of the properties typically is estimated using discounted cash flows.

Cash flow and fair value estimates require Energen Resources to make projections and assumptions for pricing, demand, competition, operating costs, legal and regulatory issues, discount rates and other factors for many years into the future. These variables can, and often do, differ from the estimates and can have a positive or negative impact on the Company’s need for impairment or on the amount of impairment. In addition, further changes in the economic and business environment can impact the Company’s original and ongoing assessments of potential impairment.

Energen Resources also may recognize impairments of capitalized costs for unproved properties. The greatest portion of these costs generally relate to the acquisition of leasehold costs and exploratory drilling costs. The costs are capitalized and periodically evaluated as to recoverability, based on changes brought about by exploration activities, changes in economic factors and potential shifts in business strategy employed by management. The Company considers a combination of geologic and engineering factors to evaluate the need for impairment of these costs.

Derivatives: Energen Resources periodically enters into commodity derivative contracts to manage its exposure to oil, natural gas and natural gas liquids price volatility. Energen Resources enters into derivative transactions that are accounted for as mark-to-market transactions with gains and losses reported in current period operating revenues. Energen Resources does not enter into derivatives or other financial instruments for trading purposes. The use of derivative contracts to mitigate price risk may cause the Company's financial position, results of operations and cash flow to be materially different from results that would have been obtained had such risk mitigation activities not occurred.

Natural Gas Distribution
Regulated Operations: Alagasco capitalizes costs as regulatory assets that otherwise would be charged to expense if it is probable that the cost is recoverable in the future through regulated rates. Likewise, if current recovery is provided for a cost that will be incurred in the future, the cost would be recognized as a regulatory liability. Alagasco's rate setting methodology, Rate Stabilization and Equalization, has been in effect since 1983.

Consolidated
Employee Benefit Plans: An employer is required to recognize the net funded status of defined benefit pensions and other postretirement benefit plans (benefit plans) as an asset or liability in its statement of financial position and to recognize changes in the funded status through comprehensive income in the year in which the changes occur. The pension benefit obligation is the projected benefit obligation, a measurement of earned benefit obligations at expected retirement salary levels; for other postretirement plans, the benefit obligation is the accumulated postretirement benefit obligation, a measurement of earned postretirement benefit obligations expected to be paid to employees upon retirement. Alagasco established a regulatory asset for the portion of the total benefit obligation to be recovered through rates in future periods.

Actuarial assumptions attempt to anticipate future events and are used in calculating the expenses and liabilities related to these plans. The calculation of the liability related to the Company's benefit plans includes assumptions regarding the appropriate weighted average discount rate, the expected long-term rate of return on the plans' assets and the estimated weighted average rate of increase in the compensation level of its employee base for defined benefit pension plans. The key assumptions used in determining these calculations are disclosed in Note 5, Employee Benefit Plans, in the Notes to Financial Statements.

In selecting each discount rate, consideration was given to Moody's Aa corporate bond rates, along with a yield curve applied to payments the Company expects to make out of its retirement plans. The yield curve is comprised of a broad base of Aa bonds with maturities between zero and thirty years. The discount rate for each plan was developed as the level equivalent rate that would produce the same present value as that using spot rates aligned with the projected benefit payments; the weighted average discount rate used to determine net periodic benefit costs was 3.63 percent for the plans for the year ended December 31, 2013. The assumed rate of return on assets is the weighted average of expected long-term asset assumptions; the return on assets used to determine net periodic benefit cost was 7 percent for each of the applicable plans for the year ended December 31, 2013. The estimated weighted average rate of increase in the compensation level for pay related plans was 3.71 percent for the year ended December 31, 2013.

The selection and use of actuarial assumptions affects the amount of benefit expense recorded in the Company’s financial statements.
The table below reflects a hypothetical 25 basis point change in assumed actuarial assumptions to pre-tax benefit expense for the year ended December 31, 2013:

(in thousands)	Pension Expense	Postretirement Expense
Discount rate change	$1,750	$10
Return on assets	$530	$180
Compensation increase	$975	$—

The weighted average discount rate, return on plan assets and estimated rate of compensation increase used in the 2014 actuarial assumptions are 4.31 percent, 7.00 percent and 3.63 percent, respectively.

Asset Retirement Obligation: The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred. Subsequent to initial measurement, liabilities are required to be accreted to their present value each period and capitalized costs are depreciated over the estimated useful life of the related assets. Upon settlement of the liability, the Company will settle the obligation for its recorded amount and recognize the resulting gain or loss. Energen Resources has an obligation to remove tangible equipment and restore land at the end of oil and gas production operations. Alagasco has certain removal cost obligations related to its gas distribution assets and a conditional asset retirement obligation to purge and cap its distribution and transmission lines upon abandonment. The estimate of future restoration and removal costs includes numerous assumptions and uncertainties, including but not limited to, inflation factors, discount rates, timing of settlement, and changes in contractual, regulatory, political, environmental, safety and public relations considerations.

Uncertain Tax Positions: The Company accounts for uncertain tax positions in accordance with accounting guidance which prescribes a recognition threshold and measurement attribute for financial statement recognition. The application of income tax law is inherently complex; laws and regulation in this area are voluminous and often ambiguous. As such, the Company is required to make many subjective assumptions and judgments regarding income tax exposures. Interpretations and guidance related to income tax laws and regulation change over time. It is possible that changes in the Company’s subjective assumptions and judgments could materially affect amounts recognized in the consolidated balance sheets and statements of income. Additional information related to the Company’s uncertain tax positions is provided in Note 4, Income Taxes, in the Notes to the Financial Statements.

RECENT PRONOUNCEMENTS OF THE FINANCIAL ACCOUNTING STANDARDS BOARD
See Note 17, Recently Issued Accounting Standards, in the Notes to Financial Statements for information regarding recently issued accounting standards.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by this item with respect to market risk is set forth in Item 7, Management’s Discussion and Analysis of Financial Condition and Results of Operations under the heading “Outlook” and in Note 8, Financial Instruments and Risk Management, in the Notes to Financial Statements.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

ENERGEN CORPORATION
ALABAMA GAS CORPORATION
INDEX TO FINANCIAL STATEMENTS
AND FINANCIAL STATEMENT SCHEDULES

Schedules other than those listed above are omitted because they are not required, not applicable, or the required information is shown in the financial statements or notes thereto.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors and Shareholders of Energen Corporation:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Energen Corporation 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 accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company’s management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management’s Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company’s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP
Birmingham, Alabama
March 3, 2014

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors and Shareholder of Alabama Gas Corporation:

In our opinion, the financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Alabama Gas Corporation at December 31, 2013 and 2012, and the results of its operations and its 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 accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related financial statements. Also in our opinion, the Company maintained, 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). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP
Birmingham, Alabama
March 3, 2014

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CONSOLIDATED STATEMENTS OF INCOME
Energen Corporation

Years ended December 31, (in thousands, except share data)	2013	2012	2011
Operating Revenues			
Oil and gas operations	$1,205,312	$1,089,230	$838,160
Natural gas distribution	533,338	451,589	534,953
Total operating revenues	1,738,650	1,540,819	1,373,113
Operating Expenses			
Cost of gas	215,455	142,228	233,523
Operations and maintenance	562,350	458,084	398,084
Depreciation, depletion and amortization	497,381	385,453	253,757
Taxes, other than income taxes	105,268	86,801	88,351
Accretion expense	6,995	6,339	5,699
Total operating expenses	1,387,449	1,078,905	979,414
Operating Income	351,201	461,914	393,699
Other Income (Expense)			
Interest expense	(69,200)	(65,542)	(44,822)
Other income	16,803	4,285	2,206
Other expense	(375)	(903)	(456)
Total other expense	(52,772)	(62,160)	(43,072)
Income From Continuing Operations Before Income Taxes	298,429	399,754	350,627
Income tax expense	105,282	144,534	126,322
Income From Continuing Operations	193,147	255,220	224,305
Discontinued Operations, net of taxes			
Income (loss) from discontinued operations	7,813	(1,658)	35,319
Gain on disposal of discontinued operations, net	3,594	—	—
Income (Loss) From Discontinued Operations	11,407	(1,658)	35,319
Net Income	$204,554	$253,562	$259,624
Diluted Earnings Per Average Common Share			
Continuing operations	$2.67	$3.53	$3.10
Discontinued operations	0.15	(0.02)	0.49
Net Income	$2.82	$3.51	$3.59
Basic Earnings Per Average Common Share			
Continuing operations	$2.67	$3.54	$3.11
Discontinued operations	0.16	(0.02)	0.49
Net Income	$2.83	$3.52	$3.60
Diluted Average Common Shares Outstanding	72,470,622	72,316,214	72,332,369
Basic Average Common Shares Outstanding	72,317,865	72,119,021	72,055,661

The accompanying Notes to Financial Statements are an integral part of these statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Energen Corporation

Years ended December 31, (in thousands)	2013	2012	2011
Net Income	$204,554	$253,562	$259,624
Other comprehensive income (loss):			
Cash flow hedges:			
Current period change in fair value of commodity derivative instruments, net of tax of ($6,660), $40,720 and $41,399, respectively	(10,866)	66,438	67,547
Reclassification adjustment for commodity derivative instruments, net of tax of ($13,560), ($17,994) and ($8,953), respectively	(22,124)	(29,359)	(14,607)
Current period change in fair value of interest rate swap, net of tax of ($80), ($1,228) and ($507), respectively	(148)	(2,281)	(941)
Reclassification adjustment for interest rate swap, net of tax of $603 and $574, respectively	1,120	1,066	—
Total cash flow hedges	(32,018)	35,864	51,999
Pension and postretirement plans:			
Amortization of net obligation at transition, net of taxes of $112, $100 and $96, respectively	207	186	177
Amortization of prior service cost, net of taxes of $90, $119 and $104, respectively	167	221	194
Amortization of net loss, net of taxes of $4,472, $1,676 and $1,270, respectively	8,306	3,113	2,359
Current period change in fair value of pension and postretirement plans, net of taxes of $6,237, ($9,393), and ($5,699), respectively	11,582	(17,443)	(10,584)
Total pension and postretirement plans	20,262	(13,923)	(7,854)
Comprehensive Income	$192,798	$275,503	$303,769

The accompanying Notes to Financial Statements are an integral part of these statements.

CONSOLIDATED BALANCE SHEETS
Energen Corporation

(in thousands)	December 31, 2013	December 31, 2012
ASSETS		
Current Assets		
Cash and cash equivalents	$5,555	$9,704
Accounts receivable, net of allowance for doubtful accounts of $5,694 and $6,549 at December 31, 2013 and 2012, respectively	257,545	277,900
Inventories		
Storage gas inventory	32,095	32,205
Materials and supplies	16,601	28,291
Liquified natural gas in storage	3,634	3,498
Regulatory assets	2,756	45,515
Income tax receivable	5,765	6,664
Assets held for sale	51,104	—
Deferred income taxes	41,299	8,520
Prepayments and other	10,877	12,823
Total current assets	427,231	425,120
Property, Plant and Equipment		
Oil and gas properties, successful efforts method	6,864,375	6,439,127
Less accumulated depreciation, depletion and amortization	1,776,802	1,765,241
Oil and gas properties, net	5,087,573	4,673,886
Utility plant	1,491,433	1,416,590
Less accumulated depreciation	605,924	573,947
Utility plant, net	885,509	842,643
Other property, net	30,556	25,107
Total property, plant and equipment, net	6,003,638	5,541,636
Other Assets		
Regulatory assets	84,890	110,566
Other postretirement assets	35,351	1,404
Long-term derivative instruments	5,439	40,577
Deferred charges and other	65,663	56,587
Total other assets	191,343	209,134
TOTAL ASSETS	$6,622,212	$6,175,890

The accompanying Notes to Financial Statements are an integral part of these statements.

CONSOLIDATED BALANCE SHEETS
Energen Corporation

(in thousands, except share data)	December 31, 2013	December 31, 2012
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Long-term debt due within one year	$60,000	$50,000
Notes payable to banks	539,000	643,000
Accounts payable	250,756	257,579
Accrued taxes	36,228	30,076
Customer deposits	21,692	24,705
Amounts due customers	16,990	19,718
Accrued wages and benefits	33,884	24,984
Regulatory liabilities	49,006	45,116
Royalty payable	51,519	34,426
Liabilities related to assets held for sale	18,545	—
Other	32,273	30,178
Total current liabilities	1,109,893	1,159,782
Long-term debt	1,343,464	1,103,528
Deferred Credits and Other Liabilities		
Asset retirement obligation	108,533	118,023
Pension liabilities	67,675	110,282
Regulatory liabilities	94,125	80,404
Deferred income taxes	1,013,245	905,601
Long-term derivative instruments	398	11,305
Other	26,860	10,275
Total deferred credits and other liabilities	1,310,836	1,235,890
Commitments and Contingencies		
Shareholders' Equity		
Preferred stock, cumulative, $0.01 par value, 5,000,000 shares authorized	—	—
Common shareholders' equity		
Common stock, $0.01 par value; 150,000,000 shares authorized, 75,574,156 shares issued at December 31, 2013 and 75,067,760 shares issued at December 31, 2012	756	751
Premium on capital stock	520,909	492,108
Capital surplus	2,802	2,802
Retained earnings	2,476,616	2,314,055
Accumulated other comprehensive income (loss), net of tax		
Unrealized gain on hedges, net	13,362	46,352
Pension and postretirement plans	(32,245)	(52,507)
Interest rate swap	(1,184)	(2,156)
Deferred compensation plan	3,259	2,774
Treasury stock, at cost: 2,967,999 shares and 2,998,620 shares at December 31, 2013 and 2012, respectively	(126,256)	(127,489)
Total shareholders' equity	2,858,019	2,676,690
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$6,622,212	$6,175,890

The accompanying Notes to Financial Statements are an integral part of these statements.

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CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
Energen Corporation

(in thousands, except share data)	Common Stock Number of Shares	Par Value	Premium on Capital Stock	Capital Surplus	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Deferred Compensation Plan	Treasury Stock	Total Shareholders' Equity
BALANCE DECEMBER 31, 2010	74,786,376	$748	$468,934	$2,802	$1,880,183	$ (74,397)	$ 3,288	$(127,515)	$2,154,043
Net income					259,624				259,624
Other comprehensive income						44,145			44,145
Purchase of treasury shares, net								(713)	(713)
Shares issued for employee benefit plans	221,036	2	7,235						7,237
Deferred compensation obligation							223	(223)	—
Stock-based compensation			5,763						5,763
Tax benefit from employee stock plans			986						986
Cash dividends - $0.54 per share					(38,922)				(38,922)
BALANCE DECEMBER 31, 2011	75,007,412	750	482,918	2,802	2,100,885	(30,252)	3,511	(128,451)	2,432,163
Net income					253,562				253,562
Other comprehensive income						21,941			21,941
Purchase of treasury shares, net								(277)	(277)
Shares issued for employee benefit plans	60,348	1	2,060						2,061
Deferred compensation obligation							(737)	737	—
Stock-based compensation			6,580					502	7,082
Tax benefit from employee stock			550						550

plans									
Cash dividends - $0.56 per share					(40,392)				(40,392)
BALANCE DECEMBER 31, 2012	75,067,760	751	492,108	2,802	2,314,055	(8,311)	2,774	(127,489)	2,676,690
Net income					204,554				204,554
Other comprehensive loss						(11,756)			(11,756)
Purchase of treasury shares, net								(1,038)	(1,038)
Shares issued for employee benefit plans	506,396	5	18,790						18,795
Deferred compensation obligation							485	(485)	—
Stock-based compensation			6,869					2,756	9,625
Tax benefit from employee stock plans			3,142						3,142
Cash dividends - $0.58 per share					(41,993)				(41,993)
BALANCE DECEMBER 31, 2013	75,574,156	$756	$520,909	$2,802	$2,476,616	$(20,067)	$3,259	$(126,256)	$2,858,019

The accompanying Notes to Financial Statements are an integral part of these statements.

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CONSOLIDATED STATEMENTS OF CASH FLOWS
Energen Corporation

Years ended December 31, (in thousands)	2013	2012	2011
Operating Activities			
Net income	$204,554	$253,562	$259,624
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	527,845	419,598	283,997
Asset impairment	29,794	21,545	—
Accretion expense	8,192	7,534	6,837
Deferred income taxes	83,650	124,399	129,041
Bad debt expense	781	153	2,525
Change in derivative fair value	48,029	(41,819)	36,210
Gain on sale of assets	(46,377)	(529)	(5,994)
Stock-based compensation expense	14,892	6,047	9,011
Exploratory expense	16,008	16,757	10,916
Other, net	23,810	8,597	7,537
Net change in:			
Accounts receivable	4,216	(11,923)	(16,359)
Inventories	11,596	10,018	(14,710)
Accounts payable	(58,859)	(16,392)	12,978
Amounts due customers, including gas supply pass-through	40,542	(57,747)	(2,597)
Income tax receivable	899	679	37,146
Pension and other postretirement benefit contributions	(11,747)	(5,996)	(5,986)
Other current assets and liabilities	29,552	1,254	11,655
Net cash provided by operating activities	927,377	735,737	761,831
Investing Activities			
Additions to property, plant and equipment	(1,195,402)	(1,184,300)	(889,614)
Acquisitions, net of cash acquired	(31,331)	(139,563)	(310,193)
Proceeds from sale of assets	174,824	2,562	7,987
Purchase of short-term investments	(310,000)	—	—
Sale of short-term investments	310,000	—	—
Other, net	(1,701)	(881)	(1,679)
Net cash used in investing activities	(1,053,610)	(1,322,182)	(1,193,499)
Financing Activities			
Payment of dividends on common stock	(41,993)	(40,392)	(38,922)
Issuance of common stock	17,780	1,224	6,415
Issuance of long-term debt	600,000	—	749,952
Reduction of long-term debt	(350,105)	(1,218)	(5,547)
Net change in short-term debt	(104,000)	628,000	(290,000)
Tax benefit on stock compensation	3,142	550	986
Other	(2,740)	(1,556)	(4,334)
Net cash provided by financing activities	122,084	586,608	418,550
Net change in cash and cash equivalents	(4,149)	163	(13,118)
Cash and cash equivalents at beginning of period	9,704	9,541	22,659
Cash and cash equivalents at end of period	$5,555	$9,704	$9,541

The accompanying Notes to Financial Statements are an integral part of these statements.

STATEMENTS OF INCOME
Alabama Gas Corporation

Years ended December 31, (in thousands)	2013	2012	2011
Operating Revenues	$533,338	$451,589	$534,953
Operating Expenses			
Cost of gas	215,455	142,228	233,523
Operations and maintenance	143,138	141,334	139,030
Depreciation and amortization	43,907	42,270	39,916
Income taxes			
Current	19,687	18,966	(1,388)
Deferred	15,000	11,278	28,058
Taxes, other than income taxes	37,070	32,541	36,268
Total operating expenses	474,257	388,617	475,407
Operating Income	59,081	62,972	59,546
Other Income (Expense)			
Allowance for funds used during construction	698	623	807
Other income	14,393	2,382	1,309
Other expense	(1,124)	(291)	(320)
Total other income	13,967	2,714	1,796
Interest Expense			
Interest on long-term debt	13,509	13,744	12,100
Other interest expense	2,140	2,540	2,640
Total interest expense	15,649	16,284	14,740
Net Income	$57,399	$49,402	$46,602

The accompanying Notes to Financial Statements are an integral part of these statements.

BALANCE SHEETS
Alabama Gas Corporation

(in thousands)	December 31, 2013	December 31, 2012
ASSETS		
Property, Plant and Equipment		
Utility plant	$1,491,433	$1,416,590
Less accumulated depreciation	605,924	573,947
Utility plant, net	885,509	842,643
Other property, net	41	42
Current Assets		
Cash	3,032	5,559
Accounts receivable		
Gas	103,301	94,011
Other	5,447	5,117
Affiliated companies	4,662	5,742
Allowance for doubtful accounts	(5,000)	(5,700)
Inventories		
Storage gas inventory	32,095	32,205
Materials and supplies	5,471	5,528
Liquified natural gas in storage	3,634	3,498
Regulatory assets	2,756	45,515
Income tax receivable	3,644	2,762
Deferred income taxes	20,049	18,799
Prepayments and other	4,654	4,451
Total current assets	183,745	217,487
Other Assets		
Regulatory assets	84,890	110,566
Other postretirement assets	26,457	848
Deferred charges and other	17,433	11,290
Total other assets	128,780	122,704
TOTAL ASSETS	$1,198,075	$1,182,876

The accompanying Notes to Financial Statements are an integral part of these statements.

BALANCE SHEETS
Alabama Gas Corporation

(in thousands, except share data)	December 31, 2013	December 31, 2012
LIABILITIES AND CAPITALIZATION		
Capitalization		
Preferred stock, cumulative, $0.01 par value, 120,000 shares authorized	$—	$—
Common shareholder’s equity		
Common stock, $0.01 par value; 3,000,000 shares authorized, 1,972,052 shares issued at December 31, 2013 and 2012, respectively	20	20
Premium on capital stock	31,682	31,682
Capital surplus	2,802	2,802
Retained earnings	350,076	325,999
Total common shareholder’s equity	384,580	360,503
Long-term debt	249,923	250,028
Total capitalization	634,503	610,531
Current Liabilities		
Notes payable to banks	50,000	77,000
Accounts payable	48,653	51,741
Accrued taxes	28,027	24,186
Customer deposits	21,692	24,705
Amounts due customers	16,990	19,718
Accrued wages and benefits	7,682	6,703
Regulatory liabilities	49,006	45,116
Other	10,113	9,018
Total current liabilities	232,163	258,187
Deferred Credits and Other Liabilities		
Deferred income taxes	205,631	189,381
Pension liabilities	20,191	43,611
Regulatory liabilities	94,125	80,404
Other	11,462	762
Total deferred credits and other liabilities	331,409	314,158
Commitments and Contingencies		
TOTAL LIABILITIES AND CAPITALIZATION	$1,198,075	$1,182,876

The accompanying Notes to Financial Statements are an integral part of these statements.

STATEMENTS OF SHAREHOLDER’S EQUITY
Alabama Gas Corporation

(in thousands, except share data)

	Common Stock Number of Shares	Par Value	Premium on Capital Stock	Capital Surplus	Retained Earnings	Total Shareholder’s Equity
Balance December 31, 2010	1,972,052	$20	$31,682	$2,802	$292,815	$327,319
Net income					46,602	46,602
Cash dividends					(29,183)	(29,183)
Balance December 31, 2011	1,972,052	20	31,682	2,802	310,234	344,738
Net income					49,402	49,402
Cash dividends					(33,637)	(33,637)
Balance December 31, 2012	1,972,052	20	31,682	2,802	325,999	360,503
Net income					57,399	57,399
Cash dividends					(33,322)	(33,322)
Balance December 31, 2013	1,972,052	$20	$31,682	$2,802	$350,076	$384,580

The accompanying Notes to Financial Statements are an integral part of these statements.

STATEMENTS OF CASH FLOWS
Alabama Gas Corporation

Years ended December 31, (in thousands)	2013	2012	2011
Operating Activities			
Net income	$57,399	$49,402	$46,602
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	43,907	42,270	39,916
Deferred income taxes	15,000	11,278	28,058
Bad debt expense	774	146	2,457
Gain on sale of assets	(10,889)	—	—
Other, net	14,068	10,667	1,560
Net change in:			
Accounts receivable	(23,955)	(13,528)	4,862
Inventories	31	10,544	(7,371)
Accounts payable	(2,464)	(5,906)	(1,499)
Amounts due customers, including gas supply pass-through	40,542	(57,747)	(2,597)
Income tax receivable	(882)	7,000	553
Pension and other postretirement benefit contributions	(6,070)	(2,725)	(2,811)
Other current assets and liabilities	2,700	(8,654)	(2,802)
Net cash provided by operating activities	130,161	42,747	106,928
Investing Activities			
Additions to property, plant and equipment	(86,037)	(69,860)	(73,447)
Proceeds from sale of assets	13,838	—	—
Other, net	(62)	(3,252)	(2,743)
Net cash used in investing activities	(72,261)	(73,112)	(76,190)
Financing Activities			
Payment of dividends on common stock	(33,322)	(33,637)	(29,183)
Proceeds from issuance of long-term debt	—	—	50,000
Reduction of long-term debt	(105)	(218)	(5,547)
Net change in short-term debt	(27,000)	62,000	(55,000)
Other	—	(38)	(101)
Net cash provided by (used in) financing activities	(60,427)	28,107	(39,831)
Net change in cash and cash equivalents	(2,527)	(2,258)	(9,093)
Cash and cash equivalents at beginning of period	5,559	7,817	16,910
Cash and cash equivalents at end of period	$3,032	$5,559	$7,817

The accompanying Notes to Financial Statements are an integral part of these statements.

NOTES TO FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Energen Corporation (Energen or the Company) is an oil and gas exploration and production company complemented by its legacy natural gas distribution business. Headquartered in Birmingham, Alabama, the Company is engaged in the development, exploration and production of oil and gas in the continental United States (oil and gas operations) and in the purchase, distribution and sale of natural gas principally in central and north Alabama (natural gas distribution). The following is a description of the Company’s significant accounting policies and practices.

A. Principles of Consolidation

The accompanying consolidated financial statements include the accounts of the Company and its subsidiaries, principally Energen Resources Corporation and Alabama Gas Corporation (Alagasco), after elimination of all significant intercompany transactions in consolidation. Certain reclassifications have been made to conform the prior years’ financial statements to the current-year presentation.

B. Oil and Gas Operations

Property and Related Depletion: Energen Resources follows the successful efforts method of accounting for costs incurred in the exploration and development of oil, gas and natural gas liquid reserves. Lease acquisition costs are capitalized initially, and unproved properties are reviewed periodically to determine if there has been impairment of the carrying value, with any such impairment charged to exploration expense currently. All development costs are capitalized. Exploratory drilling costs are capitalized pending determination of proved reserves. If proved reserves are not discovered, the exploratory drilling costs are expensed. Other exploration costs, including geological and geophysical costs, are expensed as incurred. Depreciation, depletion and amortization expense is determined on a field-by-field basis using the units-of-production method based on proved reserves. Anticipated abandonment and restoration costs are capitalized and depreciated using the units-of-production method based on proved developed reserves.

The following table sets forth capitalized exploratory well costs and includes additions pending determination of proved reserves, reclassifications to proved reserves and costs charged to expense during the year:

Years ended December 31, (in thousands)	2013	2012	2011
Capitalized exploratory well costs at beginning of period	$79,791	$70,437	$21,438
Additions pending determination of proved reserves	421,599	406,226	178,005
Reclassifications due to determination of proved reserves	(442,909)	(396,872)	(129,006)
Exploratory well costs charged to expense	(881)	—	—
Capitalized exploratory well costs at end of period	$57,600	$79,791	$70,437

The following table sets forth capitalized exploratory wells costs at year end and includes amounts capitalized for a period greater than one year:

Years ended December 31, (in thousands)	2013	2012	2011
Exploratory wells in progress	$14,794	$77,693	$70,437
Capitalized exploratory well costs for a period of one year or less	42,481	—	—
Capitalized exploratory well costs for a period greater than one year	1,206	2,098	—
Total capitalized exploratory well costs	$58,481	$79,791	$70,437

At December 31, 2013, the Company had 48 gross exploratory wells either drilling or waiting on results from completion and testing. All of these wells are located in the Permian Basin. The Company has one gross well capitalized greater than a year which is pending results from completion and testing. This well is currently waiting on facilities.

Operating Revenues: Energen Resources utilizes the sales method of accounting to recognize oil, gas and natural gas liquids production revenue. Under the sales method, revenues are based on actual sales volumes of commodities sold to purchasers.

Over-production liabilities are established only when it is estimated that a property's over-produced volumes exceed the net share of remaining reserves for such property. Energen Resources had no significant production imbalances at December 31, 2013 and 2012.

Derivative Commodity Instruments: Energen Resources periodically enters into derivative commodity instruments to hedge its exposure to price fluctuations on oil, natural gas and natural gas liquids production. Such instruments may include natural gas and crude oil over-the-counter (OTC) swaps and basis hedges typically with investment and commercial banks and energy-trading firms. All derivative commodity instruments in a gain position are valued on a discounted basis incorporating an estimate of performance risk specific to each related counterparty. Derivative commodity instruments in a loss position are valued on a discounted basis incorporating an estimate of performance risk specific to Energen. All derivative transactions are included in operating activities on the consolidated statements of cash flows.

The current policy of the Company is to not enter into agreements that require the posting of collateral. The Company has a few older agreements, none of which have active positions as of December 31, 2013, which include collateral posting requirements based on the amount of exposure and counterparty credit ratings. The majority of the Company's counterparty agreements include provisions for net settlement of transactions payable on the same date and in the same currency. Most of the agreements include various contractual set-off rights which may be exercised by the non-defaulting party in the event of an early termination due to a default.

Prior to June 30, 2013, the Company utilized cash flow hedge accounting where applicable for its derivative transactions. The effective portion of the gain or loss on the derivative instrument was recognized in other comprehensive income (OCI) as a component of shareholders' equity and subsequently reclassified as operating revenues when the forecasted transaction affects earnings. The ineffective portion of a derivative's change in fair value was required to be recognized in operating revenues immediately. All other derivative transactions not designated as cash flow hedge accounting are accounted for as mark-to-market transactions with gains or losses recognized in operating revenues in the period of change.

Effective March 31, 2013 and June 30, 2013, Energen Resources dedesignated 5,078 thousand barrels (MBbl) and 2,353 MBbl, respectively, of various Permian Basin New York Mercantile Exchange (NYMEX) oil contracts due to lack of correlation. Gains and losses from inception of the hedge to the dedesignation date were frozen and will remain in accumulated other comprehensive income until the forecasted transactions actually occur. Subsequent gains or losses will be accounted for as mark-to-market and recognized immediately through operating revenues.

Effective June 30, 2013, the Company elected to discontinue the use of cash flow hedge accounting and to dedesignate all remaining derivative commodity instruments that were previously designated as cash flow hedges. As a result of discontinuing hedge accounting, any gains or losses from inception of the hedge to June 30, 2013 were frozen and will remain in accumulated other comprehensive income until the forecasted transactions actually occur. Any subsequent gains or losses will be accounted for as mark-to-market and recognized immediately through operating revenues. As a result of the Company's election to discontinue hedge accounting, all derivative transactions entered into subsequent to June 30, 2013 will be accounted for as mark-to-market transactions with gains or losses recognized in operating revenues in the period of change.

Open mark-to-market gains (losses) on derivatives included in operating revenues were as follows:

Years ended December 31, (in thousands)	2013	2012	2011
Mark-to-market gain (loss) on derivatives	$(47,832)	$58,750	$(37,587)

All hedge transactions are pursuant to standing authorizations by the Board of Directors, which do not authorize speculative positions. The Company formally documents all relationships between hedging instruments and hedged items at the inception of the hedge, as well as its risk management objective and strategy for undertaking the hedge. This process includes specific identification of the hedging instrument and the nature of the risk being hedged.

Long-Lived Assets and Discontinued Operations: The Company reports gains and losses on the sale of certain oil and gas properties and any impairments of properties held-for-sale as discontinued operations, with income or loss from operations of the associated properties reported as income or loss from discontinued operations. The results of operations for certain held-for-sale properties are reclassified and reported as discontinued operations for prior periods. Energen Resources may, in the ordinary course of business, be involved in the sale of developed or undeveloped properties. All assets held-for-sale are reported at the lower of the carrying amount or fair value.

Acquisitions: Energen Resources recognizes all acquisitions at fair value. Energen Resources estimates the fair value of the assets acquired and liabilities assumed as of the acquisition date, the date on which Energen Resources obtained control of the properties for all acquisitions that qualify as business combinations. The fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). Fair value measurements also utilize assumptions of market participants. Energen Resources uses a discounted cash flow model and makes market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. These assumptions represent Level 3 inputs under the fair value hierarchy. Acquisition related costs are expensed as incurred in operations and maintenance (O&M) expense on the consolidated income statements.

C. Natural Gas Distribution

Regulatory Accounting: Alagasco is subject to regulation by the Alabama Public Service Commission (APSC) with respect to rates, accounting and various other matters. Alagasco capitalizes or defers certain costs or revenues, based on the approvals received from the APSC, to be recovered from or refunded to customers in future periods. These costs or revenues are recorded as regulatory assets or liabilities.

Utility Plant and Depreciation: Property, plant and equipment are stated at cost. The cost of utility plant includes an allowance for funds used during construction. Maintenance is charged for the cost of normal repairs and the renewal or replacement of an item of property which is less than a retirement unit. Gains and losses on all dispositions of land are recognized at time of disposal. When property which represents a retirement unit is replaced or removed, the cost of such property is credited to utility plant and is charged to the accumulated reserve for depreciation. The estimated net removal costs on certain gas distribution assets are charged through depreciation and recognized as a regulatory liability in accordance with regulatory accounting. Depreciation is provided using the composite method of depreciation on a straight-line basis over the estimated useful lives of utility property at rates approved by the APSC. On June 28, 2010, the APSC approved a reduction in depreciation rates, effective June 1, 2010, for Alagasco with the revised prospective composite depreciation rate approximating 3.1 percent. Related to the lower depreciation rates, Alagasco refunded to eligible customers approximately $25.6 million of refundable negative salvage costs through a one-time bill credit in July 2010. Refunds of negative salvage costs to customers through lower tariff rates were $16.3 million, $14.2 million, $22.2 million and $2.7 million for the years ended December 31, 2013, 2012 and 2011 and in December 2010, respectively. Alagasco anticipates refunding approximately $15.8 million of refundable negative salvage costs through lower tariff rates over the next twelve months. An additional estimated $39.7 million of refundable negative salvage costs will be refunded to eligible customers on a declining basis through lower tariff rates over a five year period beginning January 1, 2015. The total amount refundable to customers is subject to adjustments over the remaining five year period for charges made to the Enhanced Stability Reserve (ESR) and other APSC approved charges. The refunds as of December 2013 and the remaining amount refundable over the entire nine year period are due to a re-estimation of future removal costs provided for through the prior depreciation rates. The re-estimation was primarily the result of Alagasco’s actual removal cost experience, combined with technology improvements and Alagasco’s system efficiency improvements, during the five years prior to the approval of the reduction in depreciation rates. Approved depreciation rates averaged approximately 3.1 percent, 3.2 percent and 3.1 percent in the years ended December 31, 2013, 2012 and 2011, respectively.

Inventories: Inventories, which consist primarily of gas stored underground, are stated at average cost. Liquified natural gas is stated at base cost.

Operating Revenue and Gas Costs: Alagasco records natural gas distribution revenues in accordance with its tariff established by the APSC. The margin and gas costs on service delivered to cycle customers but not yet billed are recorded in current assets as accounts receivable with a corresponding regulatory liability. Gas imbalances are settled on a monthly basis. Alagasco had no material gas imbalances at December 31, 2013 and 2012.

Derivative Commodity Instruments: In prior years, Alagasco entered into cash flow derivative commodity instruments to hedge its exposure to price fluctuations on its gas supply pursuant to standing authorizations by the Board of Directors, which do not authorize speculative positions. Alagasco recognizes all derivatives at fair value as either assets or liabilities on the balance sheet. Any realized gains or losses are passed through to customers using the mechanisms of the Gas Supply Adjustment (GSA) rider in accordance with Alagasco's APSC approved tariff and are recognized as a regulatory asset or regulatory liability. All derivative commodity instruments in a gain position are valued on a discounted basis incorporating an estimate of performance risk specific to each related counterparty. Derivative commodity instruments in a loss position are valued on a discounted basis incorporating an estimate of performance risk specific to Alagasco.

Taxes on Revenues: The collection and payment of revenue taxes such as utility license taxes and fees, franchise fees and taxes imposed by other governmental authorities are reported on a gross basis. These amounts are included in taxes, other than income taxes on the consolidated statements of income as follows:

Years ended December 31, (in thousands)	2013	2012	2011
Taxes on revenues	$25,870	$21,479	$25,268

The collection and payment of utility gross receipts tax is presented on a net basis.

D. Fair Value Measurements

The carrying values of cash and cash equivalents, accounts payable and receivable, derivative commodity instruments, pension and postretirement plan assets and liabilities and other current assets and liabilities approximate fair value. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). All assets and liabilities are required to be classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Assessing the significance of a particular input may require judgment considering factors specific to the asset or liability, and may affect the valuation of the asset or liability and its placement within the fair value hierarchy. The fair value hierarchy that prioritizes the inputs used to measure fair value is defined as follows:

Level 1 - Unadjusted quoted prices in active markets for identical assets or liabilities;

Level 2 - Pricing inputs other than quoted prices in active markets included within Level 1, which are either directly or indirectly observable through correlation with market data as of the reporting date;

Level 3 - Pricing that requires inputs that are both significant and unobservable to the calculation of the fair value measure. The fair value measure represents estimates of the assumption that market value participants would use in pricing the asset or liability. Unobservable inputs are developed based on the best available information and subject to cost-benefit constraints.

Derivative commodity instruments are OTC derivatives valued using market transactions and other market evidence whenever possible, including market-based inputs to models and broker or dealer quotations. These OTC derivative contracts trade in less liquid markets with limited pricing information as compared to markets with actively traded, unadjusted quoted prices; accordingly, the determination of fair value is inherently more difficult. OTC derivatives for which the Company is able to substantiate fair value through directly observable market prices are classified within Level 2 of the fair value hierarchy. These Level 2 fair values consist of swaps priced in reference to NYMEX natural gas and oil futures. OTC derivatives valued using unobservable market prices have been classified within Level 3 of the fair value hierarchy. These Level 3 fair values include basin specific, basis and natural gas liquids swaps. The Company considers frequency of pricing and variability in pricing between sources in determining whether a market is considered active. While the Company does not have access to the specific assumptions used in its counterparties' valuation models, the Company maintains communications with its counterparties and discusses pricing practices. Further, the Company corroborates the fair value of its transactions by comparison of market-based price sources.

Pension and postretirement plan assets include mutual and comingled funds and limited partnerships. Plan assets were classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The determination and classification of fair value requires judgment and may affect the valuation of fair value assets and their placement within the fair value hierarchy. Level 1 and Level 2 fair values use market transactions and other market evidence whenever possible and consist primarily of equities, fixed income and mutual funds. Level 3 fair values used unobservable market prices primarily associated with certain alternative investments and a limited partnership.

E. Income Taxes

The Company uses the liability method of accounting for income taxes. Under this method, a deferred tax asset or liability is recognized for the estimated future tax effects attributable to temporary differences between the financial statement basis and the tax basis of assets and liabilities as well as tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the period of the change. The Company and its subsidiaries file a consolidated federal income tax return. Consolidated federal income taxes are charged to appropriate subsidiaries using the separate return method.

F. Accounts Receivable and Allowance for Doubtful Accounts

Trade accounts receivable are recorded at the invoiced amounts and do not bear interest. The allowance for doubtful accounts is the Company's best estimate of the amount of probable credit losses in the existing accounts receivable. The Company determines the allowance based on historical experience and in consideration of current market conditions. Account balances are charged against the allowance when it is anticipated the receivable will not be recovered.

G. Cash and Cash Equivalents

Cash and cash equivalents consist of cash in banks and investments readily convertible into cash, which have original maturities within three months at the date of acquisition. Cash equivalents are stated at cost, which approximates fair value.

H. Short-term Investments

All highly liquid financial instruments with maturities greater than three months and less than one year at the date of purchase are considered to be short-term investments. As of December 31, 2013 and 2012, Energen had no short-term investments.

I. Earnings Per Share (EPS)

The Company's basic earnings per share amounts have been computed based on the weighted average number of common shares outstanding. Diluted earnings per share amounts reflect the assumed issuance of common shares for all potentially dilutive securities.

J. Stock-Based Compensation

The Company measures all share-based compensation awards at fair value at the date of grant and expenses the awards over the requisite vesting period. Forfeitures are estimated at the time of grant and revised, if necessary, in subsequent periods if the actual forfeitures differ from those estimates. The Company recognizes all stock-based compensation expense in the period of grant, subject to certain vesting requirements, for retirement eligible employees. The Company utilizes the long-form method of calculating the available pool of windfall tax benefit. For the years ended December 31, 2013, 2012 and 2011, the Company recognized an excess tax benefit of $3.1 million, $0.6 million and $1.0 million, respectively, related to its stock-based compensation.

K. Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. The major estimates and assumptions identified by management include, but are not limited to, physical quantities of oil and gas reserves, periodic assessments of oil and gas properties for impairment, an assumption that regulatory accounting will continue as the applicable accounting standard for the Company's regulated operations, the Company's obligations under its employee pension and compensation plans, the valuation of derivative financial instruments, the allowance for doubtful accounts, tax contingency reserves, legal contingency reserves, asset retirement obligations, self insurance reserves and regulatory assets and liabilities. Due to the inherent uncertainty involved in making estimates, actual results reported in future periods may differ from the estimates.

L. Employee Benefit Plans

Energen has two defined benefit non-contributory qualified pension plans. These plans cover substantially all employees. Pension benefits for the majority of the Company's employees are based on years of service and final earnings; one plan is based on years of service and flat dollar amounts. The Company also has nonqualified supplemental pension plans covering certain officers of the Company. In addition to providing pension benefits, the Company provides certain postretirement health care and life insurance benefits for all employees hired prior to January 1, 2010. The Company continues to provide these benefits to certain non-salaried employees. These postretirement healthcare and life insurance benefits are available upon reaching normal retirement age while working for the Company. The projected unit credit actuarial method was used to determine the normal cost and actuarial liability.

For retirement plans and other postretirement plans, certain financial assumptions are used in determining the Company's projected benefit obligation. These assumptions are examined periodically by the Company, and any required changes are reflected in the subsequent determination of projected benefit obligations.

Measurement: The Company calculates periodic expense for defined benefit pension plans and other postretirement benefit plans on an actuarial basis and the net funded status of benefit plans is recognized as an asset or liability in its statement of financial position with changes in the funded status recognized through comprehensive income. For pension plans, the benefit obligation is the projected benefit obligation; for other postretirement plans, the benefit obligation is the accumulated postretirement benefit obligation. Alagasco recognizes a regulatory asset for the portion of the obligation to be recovered in rates in future periods and a regulatory liability for the portion of the plan obligation to be provided through rates in the future. The Company measures the funded status of its employee benefit plans as of the date of its year-end statement of financial position.

Discount Rate: In selecting each discount rate, consideration was given to Moody's Aa corporate bond rates, along with a yield curve applied to payments the Company expects to make out of its retirement plans. The yield curve is comprised of a broad base of Aa bonds with maturities between zero and thirty years. The discount rate for each plan was developed as the level equivalent rate that would produce the same present value as that using spot rates aligned with the projected benefit payments.

Long-Term Rate of Return: The assumed rate of return on assets is the weighted average of expected long-term asset assumptions. The Company considered past performance and current expectations for assets held by the plans as well as the expected long-term allocation of plan assets.

Other Significant Assumptions: The estimated weighted average rate of increase in the compensation level for pay related plans is another assumption used in calculation of the net periodic pension cost.

M. Environmental Costs

Environmental compliance costs, including ongoing maintenance, monitoring and similar costs, are expensed as incurred. Environmental remediation costs are accrued when remedial efforts are probable and the cost can be reasonably estimated. As more fully described in Note 2, Regulatory Matters, and as currently approved, the ESR provides deferred treatment and recovery for extraordinary O&M expenses related to environmental response costs.

2. REGULATORY MATTERS

Alagasco is subject to regulation by the APSC which established the Rate Stabilization and Equalization (RSE) rate-setting process in 1983. Alagasco's RSE order had an original term extending through December 31, 2014. On December 20, 2013, the APSC issued a final written order modifying RSE effective January 1, 2014 as follows. The term of the order is extended through September 30, 2018. The term will continue beyond September 30, 2018, unless the APSC enters an order to the contrary in a manner consistent with law. In the event of unforeseen circumstances, whether physical or economic, of the nature of force majeure and including a change in control the APSC and Alagasco will consult in good faith with respect to modifications, if any. Alagasco's allowed range of return on average common equity will be 10.5 percent to 10.95 percent with an adjusting point of 10.8 percent. Alagasco is eligible to receive a performance-based adjustment of 5 basis points to the return on equity adjusting point, based on meeting certain customer satisfaction criteria. The equity upon which a return will be permitted cannot exceed 56.5 percent of total capitalization, subject to certain adjustments. The inflation-based Cost Control Mechanism (CCM) will be adjusted to allow annual increases to O&M expense using the June Consumer Price Index For All Urban Consumers (Index Range) each rate year plus or minus 1.75 percent and from 2007 actual expenses, adjusted for inflation using the Index Range. Alagasco is on a September 30 fiscal year for rate-setting purposes (rate year) and reports on a calendar year for Securities and Exchange Commission reporting purposes.

Alagasco's allowed range of return on average common equity is 13.15 percent to 13.65 percent through December 31, 2013. Under RSE, the APSC conducts quarterly reviews to determine whether Alagasco's return on average common equity at the end of the rate year will be within the allowed range of return. Reductions in rates can be made quarterly to bring the projected return within the allowed range; increases, however, are allowed only once each rate year, effective December 1, and cannot exceed 4 percent of prior-year revenues. During the years ended December 31, 2013, 2012 and 2011, Alagasco had net pre-tax reductions in revenues of $10.6 million, $6.3 million and $6.7 million, respectively, to bring the return on average equity to midpoint within the allowed range of return. Under the provisions of RSE, a $10.3 million annual increase, $7.8 million annual increase and $13.0

million annual increase in revenues became effective December 1, 2013, 2012, and 2011, respectively. On January 1, 2014 an $8.5 million decrease in revenues became effective as a result of the December 20, 2013 RSE modification.

RSE limits the utility's equity upon which a return was permitted to 55 percent of total capitalization, subject to certain adjustments through December 31, 2013. Currently, under the inflation-based CCM established by the APSC, if the percentage change in O&M expense on an aggregate basis falls within a range of 0.75 points above or below the percentage change in the September Index Range on a rate year basis, no adjustment was required. If the change in O&M expense on an aggregate basis exceeds the Index Range, three-quarters of the difference was returned to customers. To the extent the change is less than the Index Range, the utility benefits by one-half of the difference through future rate adjustments. The O&M expense base for measurement purposes will be set at the prior year's actual O&M expense amount unless Alagasco exceeds the top of the Index Range in two successive years, in which case the base for the following year will be set at the top of the Index Range. Certain items that fluctuate based on situations demonstrated to be beyond Alagasco's control may be excluded from the CCM calculation. Alagasco's O&M expense fell within the Index Range for the rate years ended September 30, 2013, 2012 and 2011.

Alagasco's rate schedules for natural gas distribution charges contain a GSA rider, established in 1993, which permits the pass-through to customers of changes in the cost of gas supply. Alagasco's tariff provides a temperature adjustment mechanism, also included in the GSA, that is designed to moderate the impact of departures from normal temperatures on Alagasco's earnings. The temperature adjustment applies primarily to residential, small commercial and small industrial customers. Other non-temperature weather related conditions that may affect customer usage are not included in the temperature adjustment.

The APSC approved an Enhanced Stability Reserve in 1998 which was subsequently modified and expanded in 2010. As currently approved, the ESR provides deferred treatment and recovery for the following: (1) extraordinary O&M expenses related to environmental response costs; (2) extraordinary O&M expenses related to self insurance costs that exceed $1 million per occurrence; (3) extraordinary O&M expenses, other than environmental response costs and self insurance costs, resulting from a single force majeure event or multiple force majeure events greater than $275,000 and $412,500, respectively, during a rate year; and (4) negative individual large commercial and industrial customer budget revenue variances that exceed $350,000 during a rate year.
Charges to the ESR are subject to certain limitations which may disallow deferred treatment and which proscribe the timing of recovery. Funding to the ESR is provided as a reduction to the refundable negative salvage balance over its nine year term beginning December 1, 2010. Subsequent to the nine year period and subject to APSC authorization, Alagasco anticipates recovering underfunded ESR balances over a five year amortization period with an annual limitation of $660,000. Amounts in excess of this limitation are deferred for recovery in future years.

The excess of total acquisition costs over book value of net assets of acquired municipal gas distribution systems is included in utility plant and is being amortized through Alagasco's rate-setting mechanism on a straight-line basis with a weighted average remaining life of approximately 13 years. At December 31, 2013 and 2012, the net unamortized acquisition adjustments were $3.2 million and $3.8 million, respectively.

3. LONG-TERM DEBT AND NOTES PAYABLE

Long-term debt consisted of the following:

(in thousands)	December 31, 2013	December 31, 2012
Energen Corporation:		
Medium-term Notes, Series A and B, interest ranging from 7.125% to 7.6%, for notes due July 24, 2017 to February 15, 2028	$154,000	$154,000
5% Notes	—	50,000
4.625% Notes, due September 1, 2021	400,000	400,000
Senior Term Loans, (floating rate interest LIBOR plus 1.625%; 1.792% at December 31, 2013), due March 31, 2014 to December 17, 2017	600,000	—
Senior Term Loans, (floating rate interest LIBOR plus 1.375%)	—	300,000
Alabama Gas Corporation:		
5.20% Notes, due January 15, 2020	40,000	40,000
5.70% Notes, due January 15, 2035	34,923	35,028
5.368% Notes, due December 1, 2015	80,000	80,000
5.90% Notes, due January 15, 2037	45,000	45,000
3.86% Notes, due December 21, 2021	50,000	50,000
Total	1,403,923	1,154,028
Less amounts due within one year	60,000	50,000
Less unamortized debt discount	459	500
Total	$1,343,464	$1,103,528

The aggregate maturities of Energen's long-term debt for the next five years are as follows:

Years ending December 31, (in thousands)

2014	2015	2016	2017	2018
$60,000	$140,000	$60,000	$439,000	—

The aggregate maturities of Alagasco's long-term debt for the next five years are as follows:

Years ending December 31, (in thousands)

2014	2015	2016	2017	2018
—	$80,000	—	—	—

In December 2013, the Company issued $600 million in Senior Term Loans (Senior Term Loans) with a floating interest rate due March 31, 2014 through December 17, 2017. The Company used the long-term debt proceeds to repay the Senior Term Loans of $300 million issued in November 2011 and to repay short-term obligations under its syndicated credit facility.

At December 31, 2013, the Company had interest rate swap agreements with a notional of $200 million. The interest rate swaps exchange a variable interest rate for a fixed interest rate of 2.6675 percent. The fair value of the Company's interest rate swap was a $1.8 million and a $3.3 million liability at December 31, 2013 and 2012, respectively, and is classified as a Level 2 fair value liability. The fair value of the Company's interest rate swap is recognized on a gross basis on the consolidated balance sheet.

The long-term debt and short-term debt agreements of Energen and Alagasco contain financial and nonfinancial covenants including routine matters such as timely payment of principal and interest, maintenance of corporate existence and restrictions on liens.

Although none of the agreements have covenants or events of default based on credit ratings, the interest rates applicable to the Senior Term Loans and the Energen and Alagasco syndicated credit facilities discussed below may adjust based on credit rating changes. All of the Company's debt is unsecured.

Under Energen's Indenture dated September 1, 1996 with The Bank of New York as Trustee, a cross default provision provides that any debt default of more than $10 million by Energen, Alagasco or Energen Resources will constitute an event of default by Energen. Under Alagasco's Indenture dated November 1, 1993 with The Bank of New York as Trustee, a cross default provision provides that any debt default by Alagasco of more than $10 million will constitute an event of default by Alagasco. Neither Indenture includes a restriction on the payment of dividends.

Energen and Alagasco Credit Facilities: On October 30, 2012, Energen and Alagasco entered into $1.25 billion and $100 million, respectively, five-year syndicated unsecured credit facilities (syndicated credit facilities) with domestic and foreign lenders. Borrowings under these credit facilities are subject to the execution of individual note agreements each with maturity dates of less than one year. Accordingly, outstanding amounts due under these credit facilities are classified as short term obligations in the accompanying consolidated financial statements. Alagasco has been authorized by the APSC to borrow up to $200 million at any one time under the short-term credit facilities.

Energen's obligations under the $1.25 billion syndicated credit facility are unconditionally guaranteed by Energen Resources. The financial covenants of the Energen credit facility limit Energen to a maximum consolidated debt to capitalization ratio of no more than 65 percent as of the end of any fiscal quarter. Energen may not pay dividends during an event of default or if the payment would result in an event of default.

Similarly, the financial covenants of the Alagasco credit facility limit Alagasco to a maximum consolidated debt to capitalization ratio of no more than 65 percent as of the end of any fiscal quarter. Alagasco may not pay dividends during an event of default or if the payment would result in an event of default.

Under the Energen credit facility, a cross default provision provides that any debt default of more than $50 million by Energen, Alagasco or Energen Resources will constitute an event of default by Energen. Under Alagasco's credit facility, a cross default provision provides that any debt default by Alagasco of more than $50 million will constitute an event of default by Alagasco.

Upon an uncured event of default under either of the credit facilities, all amounts owing under the defaulted credit facility, if any, depending on the nature of the event of default will automatically, or may upon notice by the administrative agent or the requisite lenders thereunder, become immediately due and payable and the lenders may terminate their commitments under the defaulted facility. Energen and Alagasco were in compliance with the terms of their respective credit facilities as of December 31, 2013.

The following is a summary of information relating to the credit facilities:

(in thousands)	December 31, 2013		December 31, 2012	
Energen outstanding	$489,000		$566,000	
Alagasco outstanding	50,000		77,000	
Notes payable to banks	539,000		643,000	
Available for borrowings	811,000		707,000	
Total	$1,350,000		$1,350,000	
Energen maximum amount outstanding at any month-end	$901,000		$643,000	
Energen average daily amount outstanding	$804,895		$331,068	
Energen weighted average interest rates based on:				
Average daily amount outstanding	1.38	%	1.82	%
Amount outstanding at year-end	1.32	%	1.35	%

Alagasco maximum amount outstanding at any month-end	$75,000	$77,000
Alagasco average daily amount outstanding	$35,027	$21,254
Alagasco weighted average interest rates based on:		
Average daily amount outstanding	1.12 %	1.44 %
Amount outstanding at year-end	1.26 %	1.11 %

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Energen’s total interest expense was $69.2 million, $65.5 million and $44.8 million for the years ended December 31, 2013, 2012 and 2011, respectively. Energen’s total interest expense for the years ended December 31, 2013 and 2012 included capitalized interest expense of $0.2 million and $0.5 million. Total interest expense for Alagasco was $15.6 million, $16.3 million and $14.7 million for the years ended December 31, 2013, 2012 and 2011, respectively. At December 31, 2013, Energen and Alagasco paid commitment fees on the unused portion of available credit facilities ranging from 15 to 25 basis points per annum.

4. INCOME TAXES

The components of Energen’s income taxes consisted of the following:

Years ended December 31, (in thousands)	2013	2012	2011
Taxes estimated to be payable currently:			
Federal	$23,342	$16,295	$11,595
State	2,516	3,125	5,065
Total current	25,858	19,420	16,660
Taxes deferred:			
Federal	85,950	119,053	125,622
State	(2,300)	5,346	3,419
Total deferred	83,650	124,399	129,041
Total income tax expense	$109,508	$143,819	$145,701

The components of Energen’s income taxes consisted of the following:

Years ended December 31, (in thousands)	2013	2012	2011
Income tax expense from continuing operations	$105,282	$144,534	$126,322
Income tax expense (benefit) from discontinued operations	2,215	(715)	19,379
Income tax expense from gain on disposal of discontinued operations	2,011	—	—
Total income tax expense	$109,508	$143,819	$145,701

The components of Alagasco’s income taxes consisted of the following:

Years ended December 31, (in thousands)	2013	2012	2011
Taxes estimated to be payable currently:			
Federal	$17,495	$18,227	$(1,280)
State	2,192	739	(108)
Total current	19,687	18,966	(1,388)
Taxes deferred:			
Federal	13,252	9,066	24,938
State	1,748	2,212	3,120
Total deferred	15,000	11,278	28,058
Total income tax expense	$34,687	$30,244	$26,670

Temporary differences and carryforwards which gave rise to Energen's deferred tax assets and liabilities were as follows:

(in thousands)	December 31, 2013		December 31, 2012	
	Current	Noncurrent	Current	Noncurrent
Deferred tax assets:				
Unbilled and deferred revenue	$12,547	$—	$10,137	$—
Allowance for doubtful accounts	2,066	—	2,408	—
Insurance and other accruals	4,851	—	3,821	—
Compensation accruals	15,405	—	13,116	—
Inventories	1,260	—	1,664	—
Other comprehensive income	—	15,350	—	19,158
Gas supply adjustment related accruals	698	—	969	—
Derivative instruments	10,769	—	—	—
State net operating losses and other carryforwards	—	4,577	—	3,577
Other	1,219	1	1,340	25
Total deferred tax assets	48,815	19,928	33,455	22,760
Valuation allowance	(299)	(2,674)	(268)	(2,793)
Total deferred tax assets	48,516	17,254	33,187	19,967
Deferred tax liabilities:				
Depreciation and basis differences	—	1,008,026	—	898,625
Pension and other costs	—	15,379	—	20,143
Derivative instruments	—	2,048	4,272	3,162
Other comprehensive income	5,540	—	18,133	—
Other	1,677	5,046	2,262	3,638
Total deferred tax liabilities	7,217	1,030,499	24,667	925,568
Net deferred tax assets (liabilities)	$41,299	$(1,013,245)	$8,520	$(905,601)

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Temporary differences and carryforwards which gave rise to Alagasco's deferred tax assets and liabilities were as follows:

(in thousands)	December 31, 2013		December 31, 2012	
	Current	Noncurrent	Current	Noncurrent
Deferred tax assets:				
Unbilled and deferred revenue	$12,547	$—	$10,137	$—
Allowance for doubtful accounts	1,815	—	2,155	—
Insurance accruals	1,769	—	1,856	—
Compensation accruals	2,480	—	2,645	—
Inventories	1,260	—	1,664	—
Gas supply adjustment related accruals	698	—	969	—
Other	984	1	774	2
Total deferred tax assets	21,553	1	20,200	2
Deferred tax liabilities:				
Depreciation and basis differences	—	186,601	—	167,329
Pension and other costs	—	19,031	—	22,054
Other	1,504	—	1,401	—
Total deferred tax liabilities	1,504	205,632	1,401	189,383
Net deferred tax assets (liabilities)	$20,049	$(205,631)	$18,799	$(189,381)

The Company files a consolidated federal income tax return with all of its subsidiaries. The Company has a noncurrent deferred tax asset of $1.6 million relating to Energen Resources' $35.0 million state net operating loss carryforward which will expire beginning in 2027. Energen Resources anticipates generating adequate future taxable income to fully realize this benefit. The Company has a full valuation allowance recorded against a noncurrent deferred tax asset of $3.0 million arising from certain state net operating loss and charitable contribution carryforwards. The Company intends to fully reserve this asset until it is determined that it is more likely than not that the asset can be realized through future taxable income in the respective state taxing jurisdictions. No other valuation allowance with respect to deferred taxes is deemed necessary as the Company anticipates generating adequate future taxable income to realize the benefits of all remaining deferred tax assets on the consolidated balance sheets.

In accordance with Accounting Standards Codification 740-30-25-7, the Company has not recognized a deferred tax liability for the difference between the book basis and the tax basis in the stock of its subsidiaries. The unrecorded gross outside basis difference for Alagasco exceeds the recorded inside asset basis difference by approximately $37.0 million and would result in an additional deferred tax liability of $14.0 million.

Total income tax expense from continuing operations for the Company differed from the amount which would have been provided by applying the statutory federal income tax rate of 35 percent to earnings before taxes as illustrated below:

Years ended December 31, (in thousands)	2013	2012	2011
Income tax expense at statutory federal income tax rate	$104,450	$139,914	$122,719
Increase (decrease) resulting from:			
State income taxes, net of federal income tax benefit	3,799	4,755	8,341
Impact of state law changes	(1,966)	—	(2,059)
Qualified Section 199 production activities deduction	—	(61)	(495)
401(k) stock dividend deduction	(449)	(514)	(532)
Other, net	(552)	440	(1,652)
Total income tax expense	$105,282	$144,534	$126,322

Effective income tax rate (%)	35.28	36.16	36.03

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Total income tax expense for Alagasco differed from the amount which would have been provided by applying the statutory federal income tax rate of 35 percent to earnings before taxes as illustrated below:

Years ended December 31, (in thousands)	2013	2012	2011
Income tax expense at statutory federal income tax rate	$32,230	$27,876	$25,645
Increase (decrease) resulting from:			
State income taxes, net of federal income tax benefit	2,588	2,238	2,059
Reversal of tax reserves from audit settlements, net	—	—	(1,365)
Other, net	(131)	130	331
Total income tax expense	$34,687	$30,244	$26,670
Effective income tax rate (%)	37.67	37.97	36.40

A reconciliation of Energen's beginning and ending amount of unrecognized tax benefits is as follows:

(in thousands)	
Balance as of December 31, 2010	$24,590
Additions based on tax positions related to the current year	3,644
Additions for tax positions of prior years	2,324
Reductions for tax positions of prior years	(39)
Lapse of statute of limitations	(1,482)
Settlements	(18,444)
Balance as of December 31, 2011	10,593
Additions based on tax positions related to the current year	3,731
Additions for tax positions of prior years	269
Reductions for tax positions of prior years	(446)
Lapse of statute of limitations	(1,592)
Balance as of December 31, 2012	12,555
Additions based on tax positions related to the current year	4,546
Additions for tax positions of prior years	366
Reductions for tax positions of prior years	(46)
Lapse of statute of limitations	(1,435)
Balance as of December 31, 2013	$15,986

The reduction for settlements in 2011 are primarily related to Alagasco's tax accounting method change for the recovery of its gas distribution property that was in dispute under an Internal Revenue Service (IRS) examination of the Company's 2007-2008 federal consolidated income tax returns. In September 2010, the IRS made certain assessments primarily related to Alagasco's tax accounting method change for the recovery of its gas distribution property. The Company subsequently filed a petition in United States Tax Court challenging the IRS assessment. During the second quarter of 2011, the Company entered into a settlement agreement with the IRS. Under this settlement, Alagasco was allowed the full repair tax deductions as originally claimed in the 2007 and 2008 federal income tax returns. The Chief Judge of the United States Tax Court signed and entered the Decision putting this settlement agreement into effect on June 16, 2011.

During 2011, the Company had a gross addition of $5.9 million and recognized in its effective income tax rate $2.9 million of income tax expense for additional unrecognized tax benefit liabilities. These liabilities were partially offset by a $1.5 million benefit for the release of the unrecognized income tax benefit liability due to the Company's settlement with the IRS discussed above.

The amount of unrecognized tax benefits at December 31, 2013 that would favorably impact the Company’s effective tax rate, if recognized, is $6.9 million. The Company recognizes potential accrued interest and penalties related to unrecognized tax benefits in income tax expense. During the years ended December 31, 2013, 2012, and 2011, the Company recognized approximately $15,000 of expense, $25,000 of income and $1.4 million of income for interest (net of tax benefit) and penalties, respectively. The Company had approximately $0.2 million and $0.2 million for the payment of interest (net of tax benefit) and penalties accrued at December 31, 2013 and 2012, respectively.

A reconciliation of Alagasco’s beginning and ending amount of unrecognized tax benefits is as follows:

(in thousands)		
Balance as of December 31, 2010	$18,941	
Additions based on tax positions related to the current year	13	
Additions for tax positions of prior years	1	
Reductions for tax positions of prior years (lapse of statute of limitations)	(409	)
Settlements	(18,444	)
Balance as of December 31, 2011	102	
Additions based on tax positions related to the current year	62	
Additions for tax positions of prior years	201	
Reductions for tax positions of prior years (lapse of statute of limitations)	(58	)
Balance as of December 31, 2012	307	
Reductions for tax positions of prior years (lapse of statute of limitations)	(31	)
Balance as of December 31, 2013	$276	

The reduction for settlements in 2011 are primarily related to Alagasco’s tax accounting method change for the recovery of its gas distribution property discussed above. None of Alagasco’s unrecognized tax benefits at December 31, 2013 would impact the Company’s effective tax rate, if recognized. Alagasco recognizes potential accrued interest and penalties related to unrecognized tax benefits in income tax expense. During the years ended December 31, 2013, 2012, and 2011, Alagasco recognized approximately $4,000 of expense, $1,000 of income and $1.4 million of income for interest (net of tax benefit) and penalties, respectively. Alagasco had approximately $8,000 and $4,000 for the payment of interest (net of tax benefit) and penalties accrued at December 31, 2013 and 2012, respectively.

The Company and Alagasco’s tax returns for years 2010-2012 remain open and subject to examination by the IRS and major state taxing jurisdictions. Accordingly, it is reasonably possible that significant changes to the reserve for uncertain tax benefits may occur as a result of various audits and the expiration of the statute of limitations. Although the timing and outcome of tax examinations is highly uncertain, the Company does not expect the change in the unrecognized tax benefit within the next 12 months would have a material impact to the financial statements.

5. EMPLOYEE BENEFIT PLANS

Benefit Obligations: The following table sets forth the combined funded status of the defined qualified and nonqualified supplemental benefit plans along with the postretirement health care and life insurance benefit plans and their reconciliation with the related amounts in the Company's consolidated financial statements:

As of December 31, (in thousands)	2013	2012	2013	2012
	Pension		Postretirement Benefits	
Accumulated benefit obligation	$253,030	$269,101		
Benefit obligation:				
Balance at beginning of period	$323,540	$250,619	$85,785	$88,064
Service cost	14,173	10,527	1,694	1,853
Interest cost	11,239	10,801	3,504	4,248
Actuarial (gain) loss	(28,339)	65,048	(21,681)	(5,413)
Curtailment gain	(4,223)	—	(1,255)	—
Retiree drug subsidy program	—	—	261	360
Benefits paid	(23,036)	(13,455)	(4,726)	(3,327)
Balance at end of period	$293,354	$323,540	$63,582	$85,785
Plan assets:				
Fair value of plan assets at beginning of period	$209,424	$195,659	$87,189	$78,121
Actual return on plan assets	22,977	24,841	14,892	8,778
Employer contributions	10,169	2,379	1,578	3,617
Benefits paid	(23,036)	(13,455)	(4,726)	(3,327)
Fair value of plan assets at end of period	$219,534	$209,424	$98,933	$87,189
Funded status of plans	$(73,820)	$(114,116)	$35,351	$1,404
Noncurrent assets	$—	$—	$35,351	$1,404
Current liabilities	(6,145)	(3,834)	—	—
Noncurrent liabilities	(67,675)	(110,282)	—	—
Net asset (liability) recognized	$(73,820)	$(114,116)	$35,351	$1,404
Amounts recognized to accumulated other comprehensive income:				
Prior service costs, net of taxes	$323	$528	$—	$—
Net actuarial (gain) loss, net of taxes	37,479	52,472	(5,584)	(715)
Transition obligation, net of taxes	—	—	27	222
Total accumulated other comprehensive income (loss)	$37,802	$53,000	$(5,557)	$(493)

Alagasco recognized a regulatory asset of $58.2 million and $89.5 million as of December 31, 2013 and 2012, respectively, for the portion of the pension plan obligation to be recovered through rates in future periods. Alagasco also recognized a regulatory liability of $26.2 million and $1.2 million as of December 31, 2013 and 2012, respectively, for the portion of the postretirement health care and life insurance benefit obligation to be refunded through rates in future periods.

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Other investment assets designated for payment of the nonqualified supplemental retirement plans were as follows:

	December 31, 2013			
(in thousands)	Level 1	Level 2	Level 3	Total
Insurance contracts	$—	$14,805	$—	$14,805
United States equities	5,579	—	—	5,579
Global equities	2,338	—	—	2,338
Fixed income	—	11,039	—	11,039
Total	$7,917	$25,844	$—	$33,761

	December 31, 2012			
(in thousands)	Level 1	Level 2	Level 3	Total
Insurance contracts	$—	$7,399	$5,600	$12,999
United States equities	4,741	—	—	4,741
Global equities	2,109	—	—	2,109
Fixed income	—	10,219	—	10,219
Total	$6,850	$17,618	$5,600	$30,068

While intended for payment of the nonqualified supplemental retirement plan benefits, these assets remain subject to the claims of the Company's creditors and are not recognized in the funded status of the plan. These assets are recorded at fair value and included in deferred charges and other in the consolidated balance sheets.

The following is a reconciliation of insurance contracts in Level 3 of the fair value hierarchy:

Years ended December 31, (in thousands)	2013	2012	2011
Balance at beginning of period	$5,600	$5,332	$5,069
Unrealized gains relating to instruments held at the reporting date	—	268	263
Transfer out of Level 3	(5,600)	—	—
Balance at end of period	$—	$5,600	$5,332

Changes in Fair Value Levels: The availability of observable market data is monitored to assess the appropriate classification for financial instruments within the fair value hierarchy. Changes in economic conditions or model-based valuation techniques may require the transfer of financial instruments from one fair value level to another. In such instances, the transfer is reported at the beginning of the reporting period. For the year ended December 31, 2013, except for the transfer out of Level 3 noted below, there were no significant transfers in or out of Levels 1, 2, or 3.

Transfer of Insurance Contracts: The insurance contracts consist of multiple contracts with two insurance companies and are accounted for at fair value at the contracts' cash surrender values. During 2013, the Company determined that its insurance contracts meet the requirements to be categorized as a Level 2 fair value measurement.

The components of net periodic benefit cost were as follows:

Years ended December 31, (in thousands)	2013	2012	2011
Pension Plans			
Components of net periodic benefit cost:			
Service cost	$14,173	$10,527	$9,173
Interest cost	11,239	10,801	10,960
Expected long-term return on assets	(14,731)	(14,093)	(15,471)
Prior service cost amortization	490	517	496
Actuarial loss amortization	13,979	8,603	6,435
Termination benefit charge	—	—	414
Settlement charge	1,373	—	—
Net periodic expense	$26,523	$16,355	$12,007
Postretirement Benefit Plans			
Components of net periodic benefit cost:			
Service cost	$1,694	$1,853	$1,769
Interest cost	3,504	4,248	4,443
Expected long-term return on assets	(5,024)	(4,438)	(4,418)
Actuarial (gain) loss amortization	(120)	37	—
Transition obligation amortization	1,296	1,917	1,917
Curtailment gain	(1,229)	—	—
Net periodic expense	$121	$3,617	$3,711

Other changes in plan assets and projected benefit obligations recognized in other comprehensive income were as follows:

Years ended December 31, (in thousands)	2013	2012	2011
Pension Plans			
Net actuarial (gain) loss experienced during the year	$(14,138)	$28,748	$14,312
Net actuarial loss recognized as expense	(8,934)	(4,908)	(3,755)
Prior service cost recognized as expense	(311)	(340)	(298)
Total recognized in other comprehensive income (loss)	(23,383)	23,500	10,259
Postretirement Benefit Plans			
Net actuarial (gain) loss experienced during the year	$(8,057)	$(1,787)	$2,111
Net actuarial gain recognized as expense	550	—	—
Transition obligation recognized as expense	(283)	(294)	(286)
Total recognized in other comprehensive income (loss)	$(7,790)	$(2,081)	$1,825

Net retirement expense for Alagasco was $12.1 million, $7.8 million and $5.2 million for the years ended December 31, 2013, 2012 and 2011, respectively. In conjunction with the sale of its Black Warrior Basin coalbed methane properties in Alabama, the Company recognized a curtailment gain of $1.2 million in the fourth quarter of 2013. In the first quarter of 2013, the Company incurred a settlement charge of $0.5 million for the payment of lump sums from the nonqualified supplemental retirement plans, of which $0.1 million was expensed and $0.4 million was recognized as a pension and postretirement asset in regulatory assets at Alagasco. In the third quarter of 2013, the Company incurred a settlement charge of $64,000 for the payment of lump sums from the nonqualified supplemental retirement plans, of which $18,000 was expensed and $46,000 was recognized as a pension and postretirement asset in regulatory assets at Alagasco. In the fourth quarter of 2013, the Company incurred a settlement charge of $0.8 million for the payment of lump sums from a defined benefit pension plan. In the first quarter of 2011, the Company recognized a termination benefit charge of $0.4 million to provide for early retirement of certain non-highly compensated

employees. Net periodic postretirement benefit cost for Alagasco was $0.8 million, $2.7 million and $2.8 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Estimated amounts to be amortized from accumulated other comprehensive income into pension cost during 2014 are as follows:

(in thousands)	
Amortization of prior service cost	$314
Amortization of net actuarial loss	$5,422

Estimated amounts to be amortized from accumulated other comprehensive income into postretirement benefit cost during 2014 are as follows:

(in thousands)	
Amortization of net transition obligation	$42
Amortization of net actuarial gain	$(593)

The Company has a long-term disability plan covering most employees. The Company had expense for the years ended December 31, 2013, 2012 and 2011 of $0.6 million, $0.7 million and $0.5 million, respectively.

Assumptions: The weighted average rate assumptions to determine net periodic benefit costs were as follows:

Years ended December 31,	2013	2012	2011
Pension Plans			
Discount rate	3.63%	4.52%	4.89%
Expected long-term return on plan assets	7.00%	7.00%	7.25%
Rate of compensation increase for pay-related plans	3.71%	3.59%	3.75%
Postretirement Benefit Plans			
Discount rate	4.26%	4.95%	5.45%
Expected long-term return on plan assets	7.00%	7.00%	7.25%
Rate of compensation increase	3.70%	3.55%	3.61%

The weighted average rate assumptions used to determine the projected benefit obligations at the measurement date were as follows:

Years ended December 31,	2013	2012
Pension Plans		
Discount rate	4.31%	3.47%
Rate of compensation increase for pay-related plans	3.63%	3.71%
Postretirement Benefit Plans		
Discount rate	4.95%	4.15%
Rate of compensation increase for pay-related plans	3.60%	3.70%

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The assumed post-65 health care cost trend rates used to determine the postretirement benefit obligation at the measurement date were as follows:

As of December 31,	2013	2012
Health care cost trend rate assumed for next year	6.50%	6.75%
Rate to which the cost trend rate is assumed to decline	5.00%	5.00%
Year that rate reaches ultimate rate	2020	2020

Assumed health care cost trend rates used in determining the accumulated postretirement benefit obligation have an effect on the amounts reported. For example, revising the weighted average health care cost trend rate by 1 percentage point would have the following effects:

(in thousands)	1-Percentage Point Decrease	1-Percentage Point Increase
Effect on total of service and interest cost	$(280)	$336
Effect on net postretirement benefit obligation	$(764)	$759

Investment Strategy: The Company employs a total return investment approach whereby a mix of equities and fixed income investments are used to maximize the long-term return of plan assets with a prudent level of risk. Risk tolerance is established through consideration of plan liabilities, plan funded status, corporate financial condition and market conditions.

The Company has developed an investment strategy that focuses on asset allocation, diversification and quality guidelines. The investment goals of the Company are to obtain an adequate level of return to meet future obligations of the plan by providing above average risk-adjusted returns with a risk exposure in the mid-range of comparable funds. Investment managers are retained by the Company to manage separate pools of assets. Funds are allocated to such managers in order to achieve an appropriate, diversified, and balanced asset mix. Comparative market and peer group benchmarks are utilized to ensure that investment managers are performing satisfactorily.

The Company seeks to maintain an appropriate level of diversification to minimize the risk of large losses in a single asset class. Accordingly, plan assets for the pension plans and the postretirement health care and life insurance benefit plan do not have a concentration of assets in a single entity, industry, country, commodity or class of investment fund.

The Company’s weighted average plan asset allocations by asset category were as follows:

	Pension			Postretirement Benefits		
As of December 31,	Target	2013	2012	Target	2013	2012
Asset category:						
Equity securities	41%	34%	41%	60%	61%	60%
Debt securities	38%	28%	38%	40%	39%	40%
Other	21%	38%	21%	—%	—%	—%
Total	100%	100%	100%	100%	100%	100%

Equity securities for pension and postretirement benefits do not include the Company’s common stock.

Plan assets included in the funded status of the pension plans were as follows:

	December 31, 2013			
(in thousands)	Level 1	Level 2	Level 3	Total
United States equities	$34,117	$8,080	$—	$42,197
Global equities	20,153	13,256	—	33,409
Fixed income	—	61,121	—	61,121
Alternative investments	—	37,292	—	37,292
Cash and cash equivalents	5,970	39,545	—	45,515
Total	$60,240	$159,294	$—	$219,534

	December 31, 2012			
(in thousands)	Level 1	Level 2	Level 3	Total
United States equities	$41,907	$9,072	$—	$50,979
Global equities	23,782	10,697	—	34,479
Fixed income	—	78,806	—	78,806
Alternative investments	—	27,659	14,500	42,159
Cash and cash equivalents	—	3,001	—	3,001
Total	$65,689	$129,235	$14,500	$209,424

United States equities consist of mutual and commingled funds with varying strategies. Such strategies include stock investments across market capitalizations and investment styles. Global equities consist of mutual funds and a limited partnership that invest in United States and non-United States securities broadly diversified across mostly developed markets but with some tactical exposure to emerging markets. Fixed income securities consist of mutual funds and separate accounts. Fixed income securities are well diversified with allocations to investment grade and non-investment grade issues and issues that provide both intermediate and longer duration exposure. Alternative investments consist of limited partnerships and commingled and mutual funds with varying investment strategies. Alternative investments are meant to serve as a risk reducer at the total portfolio level as they provide asset class exposures not found elsewhere in the portfolio.

The following is a reconciliation of plan assets in Level 3 of the fair value hierarchy:

Years ended December 31, (in thousands)	2013	2012	2011
Balance at beginning of period	$14,500	$17,399	$26,841
Unrealized gains (losses)	—	992	(752)
Unrealized gains relating to instruments held at the reporting date	—	242	635
Settlements	—	(4,948)	(9,604)
Purchases	—	815	279
Transfer out of Level 3	(14,500)	—	—
Balance at end of period	$—	$14,500	$17,399

Changes in Fair Value Levels: The availability of observable market data is monitored to assess the appropriate classification for financial instruments within the fair value hierarchy. Changes in economic conditions or model-based valuation techniques may require the transfer of financial instruments from one fair value level to another. In such instances, the transfer is reported at the beginning of the cumulative reporting period. For the year ended December 31, 2013, except for the transfers out of Level 3 noted below, there were no significant transfers in or out of Levels 1, 2, or 3.

Transfer of Alternative Investments: The alternative investments consist of three investments that are measured at net asset value (NAV). NAV per share serves as an estimate for the fair value of an investment as long as certain requirements are met. During 2013, the Company determined that its alternative investments meet those requirements.

Plan assets included in the funded status of the postretirement benefit plans were as follows:

	December 31, 2013		
(in thousands)	Level 1	Level 2	Total
United States equities	$43,054	$—	$43,054
Global equities	17,048	—	17,048
Fixed income	—	38,831	38,831
Total	$60,102	$38,831	$98,933

	December 31, 2012		
(in thousands)	Level 1	Level 2	Total
United States equities	$37,482	$—	$37,482
Global equities	15,049	—	15,049
Fixed income	—	34,658	34,658
Total	$52,531	$34,658	$87,189

The Company had no Level 3 postretirement benefit plan assets. United States equities consists of mutual funds with varying strategies. These funds invest largely in medium to large capitalized companies with exposure blending growth, market-oriented and value styles. Additional fund investments include small capitalization companies, and certain of these funds utilize tax-sensitive management approaches. Global equities are mutual funds that invest in non-United States securities broadly diversified across most developed markets with exposure blending growth, market-oriented and value styles. Fixed income securities are high-quality short-duration securities including investment-grade market sectors with tactical investments in non-investment grade sectors.

Cash Flows: There are no required contributions to the qualified pension plans during 2014. Additionally, it is not anticipated that the funded status of the qualified pension plans will fall below statutory thresholds requiring accelerated funding or constraints on benefit levels or plan administration. The Company made a discretionary contribution of $3 million to the qualified pension plans in January 2014. During 2014, the Company may make additional discretionary contributions to the qualified pension plans depending on the amount and timing of employee retirements and market conditions. The Company expects to make benefit payments of approximately $6.1 million during 2014 to retirees with respect to the nonqualified supplemental retirement plans.

The following benefit payments, which reflect expected future service, as appropriate, are anticipated to be paid as follows. In addition, the following benefits reflect the expected prescription drug subsidy related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Act). The Act includes a prescription drug benefit under Medicare Part D as well as a federal subsidy which began in 2007:

(in thousands)	Pension Benefits	Postretirement Benefits	Postretirement Benefits – Prescription Drug Subsidy
2014	$66,816	$4,156	$(212)
2015	$16,572	$4,219	$(218)
2016	$18,174	$4,286	$(224)
2017	$22,167	$4,362	$(227)
2018	$28,374	$4,426	$(231)
2019-2023	$134,584	$22,319	$(1,202)

In March 2010, The Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 (collectively, Health Care Reform) was signed into law. The impact of the legislation has been estimated and is first reflected in the December 31, 2011 measurement of the post retirement benefit obligation. Energen has applied and been approved for the Early Retiree Reinsurance Program (ERRP). Energen is currently evaluating the application of the ERRP receipts, and therefore, the post retirement benefit obligations have not been reduced to reflect actual or expected receipts under the program.

6. COMMON STOCK PLANS

Energen Employee Savings Plan (ESP): A majority of Company employees are eligible to participate in the ESP by electing to contribute a portion of their compensation to the ESP. The Company may match a percentage of the contributions and make these contributions in Company common stock or in funds for the purchase of Company common stock. Employees may diversify 100 percent of their ESP Company stock account into other ESP investment options. The ESP also contains employee stock ownership plan provisions. At December 31, 2013, total shares reserved for issuance equaled 1,080,108. Expense associated with Company contributions to the ESP was $8.0 million, $7.8 million and $6.8 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Stock Incentive Plan: The Stock Incentive Plan provided for the grant of incentive stock options and non-qualified stock options to officers and key employees. The Stock Incentive Plan also provided for the grant of performance share awards and restricted stock. The Company has typically funded options, restricted stock obligations and performance share obligations through original issue shares and restricted stock through treasury shares. Under the Stock Incentive Plan, 8,600,000 shares of Company common stock were reserved for issuance with 2,921,392 remaining for issuance as of December 31, 2013.

Performance Share Awards: The Stock Incentive Plan provided for the grant of performance share awards, with each unit equal to the market value of one share of common stock, to eligible employees based on predetermined Company performance criteria at the end of an award period. The Stock Incentive Plan provided that payment of earned performance share awards be made in the form of Company common stock.

No performance share awards were granted in 2012 or 2011. A summary of performance share award activity as of December 31, 2013, and transactions during the year ended December 31, 2013 is presented below:

	Stock Incentive Plan	
	Shares	Weighted Average Price
Nonvested at December 31, 2012	—	$—
Granted (two-year vesting period)	86,221	61.14
Granted (three-year vesting period)	82,606	62.96
Forfeited	(8,008)	60.03
Nonvested at December 31, 2013	160,819	$62.13

The Company recorded expense of $4.0 million for the year ended December 31, 2013 for performance share awards with a related deferred income tax benefit of $1.5 million. During the years ended December 31, 2012 and 2011, the Company recorded no expense for performance share awards. As of December 31, 2013, there was $5.5 million of total unrecognized compensation cost related to performance share awards. These awards have a remaining weighted average requisite service period of 1.49 years.

Stock Options: The Stock Incentive Plan provided for the grant of incentive stock options, non-qualified stock options, or a combination thereof to officers and key employees. Options granted under the Stock Incentive Plan provided for the purchase of Company common stock at not less than the fair market value on the date the option is granted. The sale or transfer of the shares is limited during certain periods. All outstanding options are incentive or non-qualified, vest within three years from date of grant, and expire 10 years from the grant date.

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A summary of stock option activity as of December 31, 2013, and transactions during the years ended December 31, 2013, 2012 and 2011 are presented below:

	Stock Incentive Plan	
	Shares	Weighted Average Exercise Price
Outstanding at December 31, 2010	1,276,043	$40.16
Granted	293,978	54.99
Exercised	(227,405)	32.33
Forfeited	(4,375)	35.35
Outstanding at December 31, 2011	1,338,241	44.77
Granted	371,040	54.11
Exercised	(58,471)	24.55
Forfeited	(2,335)	46.45
Outstanding at December 31, 2012	1,648,475	47.58
Granted	137,762	49.22
Exercised	(590,119)	40.92
Forfeited	(5,074)	51.85
Outstanding at December 31, 2013	1,191,044	$51.06
Exercisable at December 31, 2011	677,753	$43.72
Exercisable at December 31, 2012	987,733	$43.75
Exercisable at December 31, 2013	713,445	$49.80
Remaining reserved for issuance at December 31, 2013	2,921,392	—

The Company uses the Black-Scholes pricing model to calculate the fair values of the options awarded. For purposes of this valuation the following assumptions were used to derive the fair values:

Grant date	10/15/2013	1/24/2013	1/25/2012	1/26/2011
Awards granted	3,686	134,076	371,040	293,978
Fair market value of stock option at grant	$30.53	$16.66	$18.79	$19.65
Expected life of award	5.8 years	5.8 years	5.8 years	5.8 years
Risk-free interest rate	1.79%	1.01%	1.07%	2.45%
Annualized volatility rate	40.6%	40.3%	39.6%	37.8%
Dividend yield	0.7%	1.2%	1.0%	1.0%

The Company recorded stock option expense of $3.6 million, $7.0 million and $5.6 million during the years ended December 31, 2013, 2012 and 2011, respectively, with a related deferred tax benefit of $1.4 million, $2.6 million and $2.1 million, respectively.

The total intrinsic value of stock options exercised during the year ended December 31, 2013, was $15.7 million. During the year ended December 31, 2013, the Company received cash of $17.8 million from the exercise of stock options. Total intrinsic value for outstanding options as of December 31, 2013, was $23.5 million and $14.9 million for exercisable options. The fair value of options vested for the year ended December 31, 2013 was $5.8 million. As of December 31, 2013, there was $0.5 million of unrecognized compensation cost related to outstanding nonvested stock options.

The following table summarizes options outstanding as of December 31, 2013:

Stock Incentive Plan

Range of Exercise Prices	Shares	Weighted Average Remaining Contractual Life
$46.45	59,330	3.00 years
$60.56	99,965	4.00 years
$29.79	78,222	5.00 years
$46.69	203,469	6.00 years
$54.99	266,166	7.00 years
$54.11	349,754	8.00 years
$48.36	130,452	9.00 years
$80.48	3,686	9.83 years
$29.79-$80.48	1,191,044	6.77 years

The weighted average remaining contractual life of currently exercisable stock options is 5.89 years as of December 31, 2013.

Restricted Stock: In addition, the Stock Incentive Plan provided for the grant of restricted stock which have been valued based on the quoted market price of the Company's common stock at the date of grant. Restricted stock awards have a three year vesting period. A summary of restricted stock activity as of December 31, 2013, and transactions during the years ended December 31, 2013, 2012 and 2011 is presented below:

	Stock Incentive Plan	
	Shares	Weighted Average Price
Nonvested at December 31, 2010	24,150	$35.49
Vested	(14,875)	30.81
Nonvested at December 31, 2011	9,275	42.99
Granted	11,115	45.24
Vested	(9,275)	42.97
Nonvested at December 31, 2012	11,115	45.24
Granted	52,650	52.34
Forfeited	(1,247)	48.36
Nonvested at December 31, 2013	62,518	$51.16

The Company recorded expense of $2.0 million, $0.1 million and $0.1 million for the years ended December 31, 2013, 2012 and 2011, respectively, related to restricted stock, with a related deferred income tax benefit of $746,000, $31,000 and $47,000, respectively. As of December 31, 2013, there was $1.2 million of total unrecognized compensation cost related to nonvested restricted stock awards recorded in premium on capital stock. These awards have a remaining requisite service period of 2.05 years.

Stock Appreciation Rights Plan: The Energen Stock Appreciation Rights Plan provided for the payment of cash incentives measured by the long-term appreciation of Company stock. Officers of the Company are not eligible to participate in this Plan. These awards are liability awards which settle in cash and are re-measured each reporting period until settlement. These awards have a three year requisite service period.

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A summary of stock appreciation rights activity as of December 31, 2013, and transactions during the years ended December 31, 2013, 2012 and 2011 are presented below:

	Stock Appreciation Rights Plan	
	Shares	Weighted Average Exercise Price
Outstanding at December 31, 2010	656,340	$38.30
Granted	189,984	54.99
Exercised/forfeited	(69,106)	41.21
Outstanding at December 31, 2011	777,218	42.00
Exercised/forfeited	(124,188)	30.90
Outstanding at December 31, 2012	653,030	44.14
Granted	88,000	48.36
Exercised/forfeited	(363,653)	39.66
Outstanding at December 31, 2013	377,377	$49.48

The Company issued the following awards with stock appreciation rights. The Company uses the Black-Scholes pricing model to calculate the fair values of the options awarded. On December 19, 2013, the Company modified certain stock appreciation rights subsequent to the original grant date. For purposes of this valuation the following assumptions were used to derive the fair values as of December 31, 2013:

Grant date	1/24/2013	1/24/2013 (modified)	1/26/2011	1/26/2011 (modified)	1/27/2010
Awards granted	87,069	931	182,199	7,785	171,749
Fair market value of award	$34.66	$27.89	$27.07	$24.21	$30.10
Expected life of award	5.6 years	2.5 years	3.6 years	2.5 years	3.0 years
Risk-free interest rate	2.04%	0.56%	1.06%	0.56%	0.80%
Annualized volatility rate	40.6%	40.6%	40.6%	40.6%	40.6%
Dividend yield	0.8%	0.8%	0.8%	0.8%	0.8%

Grant date	2/13-16/2009	1/28/2009	2/4/2008	2/1/2007
Awards granted	3,292	305,257	67,093	85,906
Fair market value of award	$39.87	$41.18	$18.50	$27.03
Expected life of award	2.5 years	2.5 years	2.0 years	1.5 years
Risk-free interest rate	0.58%	0.58%	0.39%	0.23%
Annualized volatility rate	40.6%	40.6%	40.6%	40.6%
Dividend yield	0.8%	0.8%	0.8%	0.8%

Expense associated with stock appreciation rights of $1.5 million and $4.3 million was recorded for the years ended December 31, 2013 and 2011. Income associated with stock appreciation rights of $1.0 million was recorded for the year ended December 31, 2012. During the year ended December 31, 2013, the total intrinsic value of stock appreciation rights exercised was $8.5 million. During the year ended December 31, 2013, the Company paid $5.8 million in settlement of stock appreciation rights.

Petrotech Incentive Plan: The Energen Resources' Petrotech Incentive Plan provided for the grant of stock equivalent units which may include market conditions. Officers of the Company are not eligible to participate in this Plan. These awards are liability awards which are re-measured each reporting period and settle in cash at completion of the vesting period. Stock equivalent units with service conditions were valued based on the Company's stock price at the end of the period adjusted to remove the present value of future dividends.

A summary of Petrotech unit activity as of December 31, 2013, and transactions during the years ended December 31, 2013, 2012 and 2011 are presented below:

	Petrotech Incentive Plan
	Shares
Outstanding at December 31, 2010	8,205
Granted (three-year vesting period)	6,314
Paid	(1,914)
Forfeited	(1,544)
Outstanding at December 31, 2011	11,061
Granted (three-year vesting period)	102,349
Granted (two-year vesting period)	3,768
Granted (18 month vesting period)	40,822
Paid	(3,281)
Forfeited	(13,476)
Outstanding at December 31, 2012	141,243
Granted (three-year vesting period)	92,418
Granted (17 month vesting period)	2,952
Paid	(36,792)
Forfeited	(26,529)
Outstanding at December 31, 2013	173,292

None of the awards issued included a market condition. Energen Resources recognized expense of $6.2 million, $2.6 million and $0.2 million during 2013, 2012 and 2011, respectively, related to these units.

1997 Deferred Compensation Plan: The 1997 Deferred Compensation Plan allowed officers and non-employee directors to defer certain compensation. Amounts deferred by a participant under the 1997 Deferred Compensation Plan are credited to accounts maintained for a participant in either a stock account or an investment account. The stock account tracks the performance of the Company’s common stock, including reinvestment of dividends. The investment account tracks the performance of certain mutual funds. The Company has funded, and presently plans to continue funding, a trust in a manner that generally tracks participants’ accounts under the 1997 Deferred Compensation Plan. While intended for payment of benefits under the 1997 Deferred Compensation Plan, the trust’s assets remain subject to the claims of the Company’s creditors. Amounts earned under the Deferred Compensation Plan and invested in Company common stock held by the trust have been recorded as treasury stock, along with the related deferred compensation obligation in the consolidated statements of shareholders’ equity. As of December 31, 2013 there were 695,140 shares reserved for issuance from the 1997 Deferred Compensation Plan.

1992 Energen Corporation Directors Stock Plan: In 1992 the Company adopted the Energen Corporation Directors Stock Plan to pay a portion of the compensation of its non-employee directors in shares of Company common stock. Under the Plan, 13,500 shares, 11,120 shares and 12,420 shares were awarded during the years ended December 31, 2013, 2012 and 2011, respectively, leaving 138,284 shares reserved for issuance as of December 31, 2013.

Stock Repurchase Program: By resolution adopted May 25, 1994, and supplemented by resolutions adopted April 26, 2000 and June 24, 2006, the Board authorized the Company to repurchase up to 12,564,400 shares of the Company’s common stock. There were no shares repurchased pursuant to its repurchase authorization for the years ended December 31, 2013, 2012 and 2011. As of December 31, 2013, a total of 8,992,700 shares remain authorized for future repurchase. The Company also from time to time acquires shares in connection with participant elections under the Company’s stock compensation plans. For the years ended December 31, 2013, 2012 and 2011, the Company acquired 14,766 shares, 5,459 shares and 12,867 shares, respectively, in connection with its stock compensation plans.

7. COMMITMENTS AND CONTINGENCIES

Commitments and Agreements: Under various agreements for third party gathering, treatment, transportation or other services, Energen Resources is committed to deliver minimum production volumes or to pay certain costs in the event the minimum quantities are not delivered. These delivery commitments are approximately 7.1 million barrels of oil equivalent (MMBOE) through September 2017.

Energen Resources entered into an agreement which commenced on January 15, 2012 and expires in January 2015 to secure a drilling rig necessary to execute a portion of its drilling plans. In the unlikely event that Energen Resources discontinues use of this drilling rig, Energen Resources' total resulting exposure could be as much as $3.9 million depending on the contractor's ability to remarket the drilling rig.

Certain of Alagasco's long-term contracts associated with the delivery and storage of natural gas include fixed charges of approximately $171 million through September 2024. During the years ended December 31, 2013, 2012 and 2011, Alagasco recognized approximately $50 million, $51 million and $51 million, respectively, of current-year commitments through expense and its regulatory accounts in the accompanying financial statements. Alagasco also is committed to purchase minimum quantities of gas at market-related prices or to pay certain costs in the event the minimum quantities are not taken. These purchase commitments are approximately 134 Bcf through August 2020.

Environmental Matters: Various environmental laws and regulations apply to the operations of Energen Resources and Alagasco. Historically, the cost of environmental compliance has not materially affected the Company's financial position, results of operations or cash flows. New regulations, enforcement policies, claims for damages or other events could result in significant unanticipated costs.

Under oversight of the Site Remediation Section of the Railroad Commission of Texas, the Company is currently in the process of cleanup and remediation of oil and gas wastes in nine reserve pits in Mitchell County, Texas. The Company estimates that the cleanup, remediation and related costs will approximate $2.1 million of which $1.9 million has been incurred and $0.2 million has been reserved.

During January 2014, Energen Resources responded to a General Notice and Information Request from the Environmental Protection Agency (EPA) regarding the Reef Environmental Site in Sylacauga, Talladega County, Alabama. The letter identifies Energen Resources as a potentially responsible party (PRP) under CERCLA for the cleanup of the Site. In 2008, Energen hired a third party to transport approximately 3,000 gallons of non-hazardous wastewater to Reef Environmental for wastewater treatment. Reef Environmental ceased operating its wastewater treatment system in 2010. Due to its one time use of Reef Environmental for a small volume of non-hazardous wastewater, Energen Resources has not accrued a liability for cleanup of the Site.

Alagasco is in the chain of title of nine former manufactured gas plant sites, four of which it still owns, and five former manufactured gas distribution sites, one of which it still owns. Management expects that, should future remediation of the sites be required, Alagasco's share of the remediation costs will not materially affect the financial position of Alagasco. During 2011, a removal action was completed at the Huntsville, Alabama manufactured gas plant site pursuant to an Administrative Settlement Agreement and Order on Consent among the EPA, Alagasco and the current site owner.

In 2012, Alagasco responded to an EPA Request for Information Pursuant to Section 104 of CERCLA relating to the 35th Avenue Superfund Site located in North Birmingham, Jefferson County, Alabama. The Request related to a former site of a manufactured gas distribution facility owned by Alagasco and located in the vicinity of the 35th

Avenue Superfund Site. In September 2013, Alagasco received from the EPA a General Notice Letter and Invitation to Conduct a Removal Action at the 35th Avenue Superfund Site. The letter identifies Alagasco as a PRP under CERCLA for the cleanup of the Site or costs the EPA incurs in cleaning up the Site. The EPA also offered the PRP group the opportunity to conduct Phase I of the proposed removal action which involved removal activities at approximately 50 residences that purportedly exceed certain risk levels for contamination. Alagasco has discussed its designation as a PRP further with the EPA, and Alagasco has requested additional information from the EPA regarding its designation as a PRP. Alagasco has not been provided information at this time that would allow it to determine the extent, if any, of its potential liability with respect to the 35th Avenue Superfund Site and the proposed removal action, and therefore Alagasco has not agreed to undertake the proposed removal activities and no amount has been accrued as of December 31, 2013.

Legal Matters: Energen and its affiliates are, from time to time, parties to various pending or threatened legal proceedings and the Company has accrued a provision for its estimated liability. Certain of these lawsuits include claims for punitive damages in addition to other specified relief. The Company recognizes its liability for contingencies when information available indicates both a loss is probable and the amount of the loss can be reasonably estimated. Based upon information presently available, and in light of available legal and other defenses, contingent liabilities arising from threatened and pending litigation are not considered material in relation to the respective financial positions of Energen and its affiliates. It should be noted, however, that there is uncertainty in the valuation of pending claims and prediction of litigation results.

On December 17, 2013, an incident occurred at a Housing Authority apartment complex in Birmingham, Alabama which resulted in one fatality, personal injuries and property damage. Alagasco is cooperating with the National Transportation and Safety Board which is investigating the incident. Alagasco has been named as a defendant in several lawsuits arising from the incident and additional lawsuits and claims may be filed against Alagasco.

Energen Resources previously disclosed an adverse judgment relating to the ownership of the Company operated Cadenhead 25-1 Well (the Cadenhead Well) in Ward County, Texas. Upon a Motion to Reconsider, the adverse judgment was vacated by the District Court in Ward County, Texas and a Summary Judgment Order dated July 30, 2013 was entered confirming Energen Resources' superior title to the Cadenhead Well and its associated oil and gas leases. The Summary Judgment Order has been appealed by the other party.

New Mexico Audits: During the third quarter of 2010, Energen Resources received preliminary findings from the Taxation and Revenue Department (the Department) of the State of New Mexico relating to its audit, conducted on behalf of the Office of Natural Resources Revenue (ONRR), of federal oil and gas leases in New Mexico. The audit covered periods from January 2004 through December 2008 and included a review of the computation and payment of royalties due on minerals removed from specified U.S. federal leases. The ONRR has proposed certain changes in the method of determining allowable deductions of transportation, fuel and processing costs from royalties due under the terms of the related leases.

As a result of the audit, Energen Resources has been ordered by the ONRR to pay additional royalties on the specified U.S. federal leases in the amount of $142,000 and restructure its accounting for all federal leases in two counties in New Mexico from March 1, 2004, forward. The Company preliminarily estimates that application of the Order to all of the Company's New Mexico federal leases would result in ONRR claims for up to approximately $23 million of additional royalties plus interest and penalties for the period from March 1, 2004, forward. The preliminary findings and subsequent Order (issued April 25, 2011) are contrary to deductions allowed under previous audits, retroactive in application and inconsistent with the Company's understanding of industry practice. The Company is vigorously contesting the Order and has requested additional information from the ONRR and the Department to assist the Company in evaluating the ONRR Order and the Department's findings. Management is unable, at this time, to determine a range of reasonably possible losses as a result of this Order, and no amount has been accrued as of December 31, 2013.

Lease Obligations: Alagasco leases the Company's headquarters building over a 25-year term ending January 31, 2024 and the related lease is accounted for as an operating lease. Under the terms of the lease, Alagasco has a renewal option; the lease does not contain a bargain purchase price or a residual value guarantee. Effective July 1, 2013, Alagasco subleased the Company's headquarters to Energen. Prior to July 2013, approximately 49 percent of the total headquarters lease payments were charged to Energen. As of July 2013, approximately 77 percent of the total headquarters lease payments are charged to Energen due to an increase in office space utilized by Energen. Alagasco recognizes Energen's payment of rent expense in other income with an offset in other expense. These amounts are eliminated on the consolidated statements of income. Alagasco entered into a new lease for the current Alagasco corporate headquarters in July 2013 which is classified as an operating lease. Energen's total lease payments included as operating lease expense were $25.0 million, $20.9 million and $19.1 million for the years ended December 31, 2013, 2012 and 2011, respectively. Minimum future rental payments required after 2013 under leases with initial or remaining noncancelable lease terms in excess of one year are as follows:

Years Ending December 31, (in thousands)					
2014	2015	2016	2017	2018	2019 and thereafter
$5,270	$4,940	$4,391	$3,980	$2,409	$10,637

Alagasco’s total payments related to leases included as operating expense were $2.4 million, $2.1 million and $2.3 million for the years ended December 31, 2013, 2012 and 2011, respectively. These amounts are net of approximately $0.7 million, $1.0 million and $1.0 million of lease expense paid by Energen in 2013, 2012 and 2011, respectively. Minimum future rental payments required after 2013 under leases with initial or remaining noncancelable lease terms in excess of one year are as follows:

Years Ending December 31, (in thousands)

2014	2015	2016	2017	2018	2019 and thereafter
$4,291	$4,062	$3,994	$3,979	$2,409	$10,637

Included in the table above are approximately $16.2 million of payments associated with leasing of the Company's headquarters, which are expected to be reimbursed to Alagasco by Energen through the remaining term of the related lease.

8. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Financial Instruments: The stated value of cash and cash equivalents, short-term investments, trade receivables (net of allowance), and short-term debt approximates fair value due to the short maturity of the instruments. The fair value of Energen's long-term debt, including the current portion, approximates $1,420.7 million and $1,255.8 million and has a carrying value of $1,403.9 million and $1,154.0 million at December 31, 2013 and 2012, respectively. The fair value of Alagasco's fixed-rate long-term debt, including the current portion, approximates $258.8 million and $284.7 million and has a carrying value of $249.9 million and $250.0 million at December 31, 2013 and 2012, respectively. The fair values were based on market prices of similar issues having the same remaining maturities, redemption terms and credit rating. Short-term debt is classified as Level 1 fair value and long-term debt is classified as Level 2 fair value.

Alagasco purchases gas as an agent for certain of its large commercial and industrial customers. Alagasco has, in certain instances, provided commodity-related guarantees to counterparties in order to facilitate these agency purchases. Liabilities existing for gas delivered to customers subject to these guarantees are included in the balance sheet. In the event the customer for whom the guarantee was entered fails to take delivery of the gas, Alagasco can sell such gas for the customer, with the customer liable for any resulting loss. Although the substantial majority of purchases under these guarantees are for the customers' current monthly consumption and are at current market prices, in some instances, the purchases are for an extended term at a fixed price. At December 31, 2013, the fixed price purchases under these guarantees had a maximum term outstanding through October 2014 with an aggregate purchase price of $0.5 million and a market value of $0.6 million.

Finance Receivables: Alagasco finances third-party contractor sales of merchandise including gas furnaces and appliances. At December 31, 2013 and 2012, Alagasco's finance receivable totaled approximately $10.8 million and $10.7 million, respectively. These finance receivables currently have an average balance of approximately $3,000 and with terms of up to 84 months. Financing is available only to qualified customers who meet creditworthiness thresholds for customer payment history and external agency credit reports. Alagasco relies upon ongoing payments as the primary indicator of credit quality during the term of each contract. The allowance for credit losses is recognized using an estimate of write-off percentages based on historical experience applied to an aging of the finance receivable balance. Delinquent accounts are evaluated on a case-by-case basis and, absent evidence of debt repayment after 90 days, are due in full and assigned to a third-party collection agency. The remaining finance receivable is written off approximately 12 months after being assigned to the third-party collection agency. Alagasco had finance receivables past due 90 days or more of $0.4 million and $0.5 million as of December 31, 2013 and 2012, respectively.

The following table sets forth a summary of changes in the allowance for credit losses as follows:

(in thousands)	
Allowance for credit losses as of December 31, 2011	$421
Provision	49
Allowance for credit losses as of December 31, 2012	470

Provision	(47)
Allowance for credit losses as of December 31, 2013	$423

Risk Management: At December 31, 2013, the counterparty agreements under which the Company had active positions did not include collateral posting requirements. The Company is at risk for economic loss based upon the creditworthiness of its counterparties. Energen Resources was in a net gain position with seven of its active counterparties and in a net loss position with the remaining six at December 31, 2013. The two largest counterparty net gain positions at December 31, 2013, Macquarie Bank Limited and J Aron & Company, constituted approximately $8.6 million and $5.3 million of Energen Resources' total net loss on fair value of derivatives.

The following table details the fair values of commodity contracts by business segment on the balance sheets:

(in thousands)	December 31, 2013		
	Oil and Gas Operations	Natural Gas Distribution	Total
Derivative assets or (liabilities) not designated as hedging instruments			
Accounts receivable	36,224	—	36,224
Long-term asset derivative instruments	7,992	—	7,992
Total derivative assets	44,216	—	44,216
Accounts receivable	(18,761)*	—	(18,761)
Long-term asset derivative instruments	(2,553)*	—	(2,553)
Accounts payable	(30,302)	—	(30,302)
Total derivative liabilities	(51,616)	—	(51,616)
Total derivatives not designated	(7,400)	—	(7,400)

(in thousands)	December 31, 2012		
	Oil and Gas Operations	Natural Gas Distribution	Total
Derivative assets or (liabilities) designated as hedging instruments			
Accounts receivable	$87,514	$—	$87,514
Long-term asset derivative instruments	37,954	—	37,954
Total derivative assets	125,468	—	125,468
Accounts receivable	(37,326)*	—	(37,326)
Long-term asset derivative instruments	(6,810)*	—	(6,810)
Long-term liability derivative instruments	(8,726)	—	(8,726)
Total derivative liabilities	(52,862)	—	(52,862)
Total derivatives designated	72,606	—	72,606
Derivative assets or (liabilities) not designated as hedging instruments			
Accounts receivable	14,604	—	14,604
Long-term asset derivative instruments	9,433	—	9,433
Total derivative assets	24,037	—	24,037
Accounts payable	—	(2,593)	(2,593)
Long-term liability derivative instruments	(874)	—	(874)
Total derivative liabilities	(874)	(2,593)	(3,467)
Total derivatives not designated	23,163	(2,593)	20,570
Total derivatives	$95,769	$(2,593)	$93,176

* Amounts classified in accordance with accounting guidance which permits offsetting fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement.

The Company had a net $8.2 million and a net $28.4 million deferred tax liability included in current and noncurrent deferred income taxes on the consolidated balance sheets related to derivative items included in other comprehensive income as of December 31, 2013 and 2012, respectively.

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The following table details the effect of derivative commodity instruments designated as hedging instruments on the financial statements:

Years ended December 31, (in thousands)	Location on Income Statement	2013	2012	2011
Net gain (loss) recognized in OCI on derivative (effective portion), net of tax of ($6,660), $40,720 and $41,399	—	$(10,866)	$66,438	$67,547
Gain reclassified from accumulated OCI into income (effective portion)	Operating revenues	$34,293	$52,694	$26,326
Gain (loss) recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	Operating revenues	$835	$(5,340)	$(2,767)

The following table details the effect of open and closed derivative commodity instruments not designated as hedging instruments on the income statement:

Years ended December 31, (in thousands)	Location on Income Statement	2013	2012	2011
Gain (loss) recognized in income on derivative	Operating revenues	$(73,980)	$61,841	$(37,587)

As of December 31, 2013, $13.4 million of deferred net gains on derivative instruments recorded in accumulated other comprehensive income, net of tax, are expected to be reclassified and reported in earnings as operating revenues during the next twelve-month period. As of December 31, 2013, the Company had 51.8 billion cubic feet (Bcf) and 6.0 Bcf of natural gas hedges which expire during 2014 and 2015, respectively, that are considered mark-to-market transactions. The Company had 9.8 million barrels (MMBbl) and 5.8 MMBbl of oil hedges which expire during 2014 and 2015, respectively, that are considered mark-to-market transactions. The Company had 1.9 million gallons (MMgal) of natural gas liquid hedges which expire during 2014 that are considered mark-to-market transactions. During 2013, the Company discontinued hedge accounting and reclassified gains of $4.5 million after-tax from other comprehensive income into operating revenues when Energen Resources determined it was probable certain forecasted volumes would not occur due to certain properties being held for sale or sold.

As of December 31, 2013, Energen Resources entered into the following transactions for 2014 and subsequent years:

Production Period	Total Hedged Volumes		Average Contract Price	Description
Natural Gas				
2014	10.6	Bcf	$4.55 Mcf	NYMEX Swaps
	31.4	Bcf	$4.60 Mcf	Basin Specific Swaps - San Juan
	9.7	Bcf	$3.81 Mcf	Basin Specific Swaps - Permian
2015	6.0	Bcf	$4.07 Mcf	Basin Specific Swaps - San Juan
Oil				
2014	9,796	MBbl	$92.64 Bbl	NYMEX Swaps
2015	5,760	MBbl	$88.85 Bbl	NYMEX Swaps

As of December 31, 2013, the maximum term over which Energen Resources has hedged exposures to the variability of cash flows is through December 31, 2015. Alagasco has not entered into any cash flow derivative transactions on its gas supply since 2010.

The following sets forth derivative assets and liabilities that were measured at fair value on a recurring basis:

	December 31, 2013		
(in thousands)	Level 2*	Level 3*	Total
Current assets	$(1,658)	$19,121	$17,463
Noncurrent assets	4,383	1,056	5,439
Current liabilities	(28,414)	(1,888)	(30,302)
Net derivative asset (liability)	$(25,689)	$18,289	$(7,400)

	December 31, 2012		
(in thousands)	Level 2*	Level 3*	Total
Current assets	$(3,629)	$68,421	$64,792
Noncurrent assets	18,899	21,678	40,577
Current liabilities	(2,593)	—	(2,593)
Noncurrent liabilities	(8,520)	(1,080)	(9,600)
Net derivative asset	$4,157	$89,019	$93,176

* Amounts classified in accordance with accounting guidance which permits offsetting fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement.

As of December 31, 2013, Alagasco had no derivative instruments. As of December 31, 2012, Alagasco had $2.6 million of derivative instruments which were classified as Level 2 fair values and are included in the above table as current liabilities, respectively. Alagasco had no derivative instruments classified as Level 3 fair values as of December 31, 2013 and 2012.

The Company has prepared a sensitivity analysis to evaluate the hypothetical effect that changes in the prices used to estimate fair value would have on the fair value of its derivative instruments. The Company estimates that a 10 percent increase or decrease in commodity prices would result in an approximate $19 million change in the fair value of open Level 3 derivative contracts. The resulting impact upon the results of operations would be an approximate $19 million associated with open Level 3 mark-to-market derivative contracts. Liquidity requirements to meet the obligation would not be significantly impacted as gains and losses on the derivative contracts would be similarly offset by sales at the spot market price.

The table below sets forth a summary of changes in the fair value of the Company’s Level 3 derivative commodity instruments as follows:

Years ended December 31, (in thousands)	2013	2012	2011
Balance at beginning of period	$89,019	$65,801	$42,755
Realized gains	55,210	63,720	52,716
Unrealized gains (losses) relating to instruments held at the reporting date*	(71,367)	22,160	23,980
Settlements during period	(54,573)	(62,662)	(53,650)
Balance at end of period	$18,289	$89,019	$65,801

*Includes $7.6 million in mark-to-market losses, $19.9 million in mark-to-market gains and $5.2 million in mark-to-market losses for the years ended December 31, 2013, 2012 and 2011, respectively.

The tables below set forth quantitative information about the Company's Level 3 fair value measurements of derivative commodity instruments as follows:

(in thousands)	Fair Value as of December 31, 2013	Valuation Technique*	Unobservable Input*	Range
Natural Gas Basis - San Juan				
2014	$18,159	Discounted Cash Flow	Forward Basis	($0.17 - $0.20) Mcf
2015	$1,056	Discounted Cash Flow	Forward Basis	($0.26) Mcf
Natural Gas Basis - Permian				
2014	$(1,948)	Discounted Cash Flow	Forward Basis	($0.18 - $0.20) Mcf
Natural Gas Liquids				
2014	$1,022	Discounted Cash Flow	Forward Price	$0.80 - $0.81 Gal

*Discounted cash flow represents an income approach in calculating fair value including the referenced unobservable input and a discount reflecting credit quality of the counterparty.

The tables below set forth information about the offsetting of derivative assets and liabilities as follows:

	December 31, 2013					
				Gross Amounts Not Offset in the Balance Sheets		
(in thousands)	Gross Amounts Recognized	Gross Amounts Offset in the Balance Sheets	Net Amount Presented in the Balance Sheets	Financial Instruments	Cash Collateral Received	Net Amount
Derivative assets	$44,215	$(21,313)	$22,902	$—	$—	$22,902
Derivative liabilities	$51,615	$(21,313)	$30,302	$—	$—	$30,302

	December 31, 2012					
				Gross Amounts Not Offset in the Balance Sheets		
(in thousands)	Gross Amounts Recognized	Gross Amounts Offset in the Balance Sheets	Net Amount Presented in the Balance Sheets	Financial Instruments	Cash Collateral Received	Net Amount
Derivative assets	$149,504	$(44,135)	$105,369	$—	$—	$105,369
Derivative liabilities	$56,328	$(44,135)	$12,193	$—	$—	$12,193

Concentration of Credit Risk: Revenues and related accounts receivable from oil and gas operations primarily are generated from the sale of produced oil and natural gas to energy marketing companies. Such sales are typically made on an unsecured credit basis with payment due the month following delivery. This concentration of sales to the energy marketing industry has the potential to affect the Company's overall exposure to credit risk, either positively or negatively, in that the Company's oil and gas purchasers may be affected similarly by changes in economic, industry or other conditions. Energen Resources considers the credit quality of its purchasers and, in certain instances, may require credit assurances such as a deposit, letter of credit or parent guarantee. The two largest oil and gas purchasers accounted for approximately 35 percent and 12 percent of Energen Resources' accounts receivable for commodity sales as of December 31, 2013. Energen Resources' other purchasers each accounted for less than 9 percent of these accounts receivable as of December 31, 2013. During the year ended December 31, 2013, Plains Marketing, LP, accounted for approximately 25 percent of consolidated total operating revenues. All other oil and gas purchasers each accounted for less than 10 percent of consolidated total operating revenues for the year ended December 31, 2013.

Natural gas distribution operating revenues and related accounts receivable are generated from state-regulated utility natural gas sales and transportation to approximately 422,000 residential, commercial and industrial customers located in central and north Alabama. A change in economic conditions may affect the ability of customers to meet their obligations; however, the Company believes that its provision for possible losses on uncollectible accounts receivable is adequate for its credit loss exposure.

9. RECONCILIATION OF EARNINGS PER SHARE

Years ended December 31, (in thousands, except per share amounts)	2013			2012			2011		
	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic EPS	$204,554	72,318	$2.83	$253,562	72,119	$3.52	$259,624	72,056	$3.60
Effect of dilutive securities									
Stock options		112			196			270	
Non-vested restricted stock		20			1			6	
Performance share awards		21			—			—	
Diluted EPS	$204,554	72,471	$2.82	$253,562	72,316	$3.51	$259,624	72,332	$3.59

The Company had the following shares that were excluded from the computation of diluted EPS, as their effect was non-dilutive.

Years ended December 31, (in thousands)	2013	2012	2011
Stock options	134,138	849,583	293,978
Non-vested restricted stock	6,529	—	—
Performance share awards	4,121	—	—

10. ASSET RETIREMENT OBLIGATIONS

The Company recognizes a liability for the fair value of asset retirement obligations (ARO) in the period incurred. Subsequent to initial measurement, liabilities are accreted to their present value and capitalized costs are depreciated over the estimated useful life of the related assets. Upon settlement of the liability, the Company may recognize a gain or loss for differences between estimated and actual settlement costs. The ARO fair value liability is recognized on a discounted basis incorporating an estimate of performance risk specific to the Company. Revisions in estimates to the ARO result from revisions to the estimated timing or amount of the underlying cash flows. In 2013, 2012 and 2011, Energen Resources recognized amounts representing expected future costs associated with site reclamation, facilities dismantlement, and plug and abandonment of wells as follows:

(in thousands)		
Balance as of December 31, 2010	$97,415	
Liabilities incurred	4,627	
Liabilities settled	(1,539	)
Accretion expense (including discontinued operations of $1,138)	6,837	
Balance as of December 31, 2011	107,340	
Liabilities incurred	3,994	
Liabilities settled	(845	)
Accretion expense (including discontinued operations of $1,195)	7,534	
Balance as of December 31, 2012	118,023	
Liabilities incurred	2,772	
Liabilities settled	(5,525	)
Accretion expense (including discontinued operations of $1,197)	8,192	

Reclassification associated with held for sale properties*	(14,929)
Balance as of December 31, 2013	$108,533

* Asset retirement obligation associated with North Louisiana/East Texas properties are included as liabilities related to assets held for sale in current liabilities on the balance sheet.

The Company recognizes conditional obligations if such obligations can be reasonably estimated and a legal requirement to perform an asset retirement activity exists. Alagasco accrues removal costs on certain gas distribution assets over the useful lives of its property, plant and equipment through depreciation expense in accordance with rates approved by the APSC. Alagasco recorded a conditional asset retirement obligation, on a discounted basis, of $27.5 million and $24.9 million to purge and cap its gas pipelines upon abandonment and to remediate other related obligations, as a regulatory liability as of December 31, 2013 and 2012, respectively. Regulatory assets for rate recovery of accumulated asset removal costs of $4.6 million and $3.3 million as of December 31, 2013 and 2012, respectively, are included as regulatory assets in noncurrent assets on the balance sheets. The costs associated with asset retirement obligations are either currently being recovered in rates or are probable of recovery in future rates.

11. SUPPLEMENTAL CASH FLOW INFORMATION

Supplemental information concerning Energen's cash flow activities was as follows:

Years ended December 31, (in thousands)	2013	2012	2011
Interest paid, net of amount capitalized	$65,143	$61,379	$33,601
Income taxes paid	$25,081	$17,170	$9,432
Noncash investing activities:			
Accrued development, exploration costs and other capital	$99,128	$120,024	$72,030
Capitalized depreciation	$66	$80	$93
Capitalized asset retirement obligations costs	$3,574	$4,409	$4,927
Allowance for funds used during construction	$698	$623	$807
Capital lease obligations	$—	$5,072	$—
Noncash financing activities:			
Issuance of common stock for employee benefit plans	$1,015	$838	$822
Treasury stock acquired in connection with tax withholdings	$977	$277	$713

Supplemental information concerning Alagasco's cash flow activities was as follows:

Years ended December 31, (in thousands)	2013	2012	2011
Interest paid, net of amount capitalized	$13,465	$13,513	$12,385
Income taxes paid	$23,138	$16,796	$5,143
Interest expense (revenue) on affiliated company debt, net	$(18)	$295	$376
Noncash investing activities:			
Accrued property, plant and equipment costs	$5,505	$3,536	$2,229
Capitalized depreciation	$66	$80	$93
Capitalized asset retirement obligations costs	$802	$415	$300
Allowance for funds used during construction	$698	$623	$807

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12. ACQUISITION AND DISPOSITION OF PROPERTIES

In August 2013, Alagasco recorded a pre-tax gain of $10.9 million related to the sale of its Metro Operations Center which is located in Birmingham, Alabama, and has been in service since the 1940's. The Company received approximately $13.8 million pre-tax in cash from the sale of this property. During the third quarter of 2013, the gain on the sale was recognized in other income and a related reduction in revenues was recognized to defer the gain as a regulatory liability pending review by the APSC. In conjunction with the receipt of the rate order from the APSC on December 20, 2013, Alagasco recognized the deferred revenues from this sale in the fourth quarter of 2013. Effective upon the sale of the Metro Operations Center, Alagasco leased the facility from the purchaser for a period of approximately 20 months.

During 2013, Energen also completed a total of approximately $31.3 million in various purchases of unproved leasehold properties.

On February 21, 2012, Energen Resources entered into a definitive agreement with BHP Billiton (BHP) to buy a 50 percent undivided interest in three existing wells in Reeves County, Texas, from Energen Resources for approximately $18 million. Following the purchase of the wells, BHP completed two of the wells and earned a 50 percent undivided interest in 4,829 net acres. The agreement also included the option for BHP to purchase from Energen Resources a 50 percent undivided interest in 51,720 net acres in the Permian Basin. On May 1, 2012, BHP elected not to exercise the option.

On February 14, 2012, Energen completed the purchase of certain properties in the Permian Basin for a cash purchase price of $68 million. This purchase had an effective date of December 1, 2011. Energen acquired total proved reserves of approximately 8.2 MMBOE. Of the proved reserves acquired, an estimated 81 percent are undeveloped. Approximately 64 percent of the proved reserves are oil, 22 percent are natural gas liquids and natural gas comprises the remaining 14 percent. Energen Resources used its credit facilities and internally generated cash flows to finance the acquisition. Pro forma financial information for this acquisition is not presented because it would not be materially different from the information presented in the consolidated statements of income.

The following table summarizes the consideration paid and the amounts of the assets acquired and liabilities assumed recognized as of February 14, 2012 (including the effects of closing adjustments).

(in thousands)	
Consideration given	
Cash (net)	$67,615
Recognized amounts of identifiable assets acquired and liabilities assumed	
Proved properties	$65,581
Unproved leasehold properties	911
Accounts receivable	1,358
Accounts payable	(25)
Asset retirement obligation	(210)
Total identifiable net assets	$67,615

Included in the Company's consolidated results of operations for the year ended December 31, 2012, were $11.7 million of operating revenues and $3.1 million in operating income resulting from the operation of the properties acquired above.

In December 2012, Energen completed the purchase of liquids-rich properties in the Permian Basin for a cash purchase price of approximately $18.7 million. During 2012, Energen also completed a total of approximately $18 million in various purchases of unproved leasehold properties.

On December 27, 2011, Energen completed the purchase of certain properties in the Permian Basin for a cash purchase price of $60 million. This purchase had an effective date of July 1, 2011. Energen acquired total proved reserves of approximately 3.4 MMBOE. Of the proved reserves acquired, an estimated 77 percent are undeveloped. Approximately 61 percent of the proved reserves are oil, 24 percent are natural gas liquids and natural gas comprises the remaining 15 percent. Energen Resources used its credit facilities and internally generated cash flows to finance the acquisition. Pro forma financial information for this acquisition is not presented because it would not be materially different from the information presented in the consolidated statements of income.

The following table summarizes the consideration paid and the amounts of the assets acquired and liabilities assumed recognized as of December 27, 2011 (including the effects of closing adjustments).

(in thousands)	
Consideration given	
Cash (net)	$60,017
Recognized amounts of identifiable assets acquired and liabilities assumed	
Proved properties	$36,068
Unproved leasehold properties	23,686
Accounts receivable	680
Accounts payable	(244)
Asset retirement obligation	(173)
Total identifiable net assets	$60,017

The impact to operating revenues and operating income from this acquisition was not material for the year ended December 31, 2011.

On November 16, 2011, Energen completed the purchase of certain properties in the Permian Basin for a cash purchase price of $162 million. This purchase had an effective date of August 1, 2011. Energen acquired total proved reserves of approximately 13.6 MMBOE. Of the proved reserves acquired, an estimated 76 percent are undeveloped. Approximately 59 percent of the proved reserves are oil, 25 percent are natural gas liquids and natural gas comprises the remaining 16 percent. Energen Resources used its credit facilities and internally generated cash flows to finance the acquisition. Pro forma financial information for this acquisition is not presented because it would not be materially different from the information presented in the consolidated statements of income.

The following table summarizes the consideration paid and the amounts of the assets acquired and liabilities assumed recognized as of November 16, 2011 (including the effects of closing adjustments).

(in thousands)	
Consideration given	
Cash (net)	$161,967
Recognized amounts of identifiable assets acquired and liabilities assumed	
Proved properties	$151,544
Unproved leasehold properties	7,883
Accounts receivable	3,070
Accounts payable	(388)
Asset retirement obligation	(142)
Total identifiable net assets	$161,967

The impact to operating revenues and operating income from this acquisition was not material for the year ended December 31, 2011.

In July 2011, Energen completed the purchase of properties in the Permian Basin for a cash purchase price of approximately $20 million. In April 2011, Energen completed the purchase of unproved leasehold properties for a cash purchase price of approximately $37 million covering an estimated 11,000 net acres in the Permian Basin.

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13. DISCONTINUED OPERATIONS

In October 2013, Energen Resources completed the sale of its Black Warrior Basin coalbed methane properties in Alabama for $160 million (subject to closing adjustments). The Company recorded a pre-tax gain on the sale of approximately $35 million in the fourth quarter of 2013 which is reflected in gain on disposal of discontinued operations in the year ended December 31, 2013. The sale had an effective date of July 1, 2013, and the proceeds from the sale were used to repay short-term obligations. The property was classified as held-for-sale and reflected in discontinued operations during the third quarter of 2013. At December 31, 2012, proved reserves associated with Energen's Black Warrior Basin properties totaled 97 Bcf of natural gas.

In January 2014, Energen Resources signed a purchase and sale agreement on its North Louisiana/East Texas natural gas and oil properties for $31.5 million (subject to closing adjustments). The Company expects to complete the sale in the first quarter of 2014 and will use the proceeds to repay short-term obligations. During the third quarter of 2013, Energen Resources classified these natural gas and oil properties as held-for-sale and reflected the associated operating results in discontinued operations. Energen Resources recognized a non-cash impairment writedown on these properties in the third and fourth quarters of $24.6 million pre-tax and $5.2 million pre-tax, respectively, to adjust the carrying amount of these properties to their fair value based on an estimate of the selling price of the properties. The non-cash impairment writedowns are reflected in gain on disposal of discontinued operations in the year ended December 31, 2013. Significant assumptions in valuing the proved reserves included the reserve quantities, anticipated operating costs, anticipated production taxes, future expected natural gas prices and basis differentials, anticipated production declines, and a discount rate of 10 percent commensurate with the risk of the underlying cash flow estimates. The impairment writedowns are classified as Level 3 fair value. At December 31, 2013, proved reserves associated with Energen's North Louisiana/East Texas properties totaled 23 Bcf of natural gas and 91 MBbl of oil.

The following table details held-for-sale properties by major classes of assets and liabilities:

(in thousands)	December 31, 2013		
	Black Warrior Basin	North Louisiana/East Texas	Total
Accounts receivable	$2,829	$1,272	$4,101
Inventories	—	68	68
Oil and gas properties	—	348,379	348,379
Less accumulated depreciation, depletion and amortization	—	(301,609)	(301,609)
Other property, net	—	165	165
Total assets held-for-sale	2,829	48,275	51,104
Accounts payable	(1,732)	(11)	(1,743)
Royalty payable	(550)	(869)	(1,419)
Other current liabilities	(379)	(21)	(400)
Other long-term liabilities	—	(14,983)	(14,983)
Total liabilities held-for-sale	(2,661)	(15,884)	(18,545)
Total held-for-sale properties	$168	$32,391	$32,559

During the first quarter of 2012, Energen Resources recognized a non-cash impairment writedown on certain properties in East Texas of $21.5 million pre-tax to adjust the carrying amount of these properties to their fair value based on expected future discounted cash flows. This non-cash impairment writedown is reflected in loss from discontinued operations for the year ended December 31, 2012. The impairment was caused by the impact of lower future natural gas prices. This impairment writedown is classified as Level 3 fair value.

Gains and losses on the sale of certain oil and gas properties and any impairments of properties held-for-sale are reported as discontinued operations, with income or loss from operations of the associated properties reported as income or loss from discontinued operations. Accordingly, the results of operations for certain held-for-sale properties were reclassified and reported as discontinued operations for all prior periods presented. Energen Resources may, in the ordinary course of business, be involved in the sale of developed or undeveloped properties. All assets held-for-sale are reported at the lower of the carrying amount or fair value.

Years ended December 31, (in thousands, except per share data)	2013	2012	2011
Oil and gas revenues	$60,191	$76,350	$110,366
Pretax income (loss) from discontinued operations	$10,028	$(2,373)	$54,698
Income tax expense (benefit)	2,215	(715)	19,379
Income (Loss) From Discontinued Operations	$7,813	$(1,658)	$35,319
Gain on disposal of discontinued operations, net	$5,605	$—	$—
Income tax expense	2,011	—	—
Gain on Disposal of Discontinued Operations, net	$3,594	$—	$—
Total Income (Loss) From Discontinued Operations	$11,407	$(1,658)	$35,319
Diluted Earnings Per Average Common Share			
Income (Loss) from Discontinued Operations	$0.10	$(0.02)	$0.49
Gain on Disposal of Discontinued Operations, net	0.05	—	—
Total Income (Loss) From Discontinued Operations	$0.15	$(0.02)	$0.49
Basic Earnings Per Average Common Share			
Income (Loss) from Discontinued Operations	$0.11	$(0.02)	$0.49
Gain on Disposal of Discontinued Operations, net	0.05	—	—
Total Income (Loss) From Discontinued Operations	$0.16	$(0.02)	$0.49

14. REGULATORY ASSETS AND LIABILITIES

The following table details regulatory assets and liabilities on the consolidated balance sheets:

(in thousands)	December 31, 2013		December 31, 2012	
	Current	Noncurrent	Current	Noncurrent
Regulatory assets:				
Pension assets	$325	$58,243	$170	$90,708
Accretion and depreciation for asset retirement obligation	—	18,046	—	16,536
Risk management activities	—	—	2,593	—
Rate recovery of asset removal costs, net	—	4,601	—	3,322
Enhanced stability reserve	—	4,000	—	—
Gas supply adjustment	2,406	—	42,726	—
Other	25	—	26	—
Total regulatory assets	$2,756	$84,890	$45,515	$110,566
Regulatory liabilities:				
RSE adjustment	$4,690	$—	$1,740	$—
Unbilled service margin	28,504	—	25,078	—
Postretirement liabilities	—	26,197	—	1,237
Refundable negative salvage	15,779	39,663	18,265	53,467
Asset retirement obligation	—	27,528	—	24,930
Other	33	737	33	770
Total regulatory liabilities	$49,006	$94,125	$45,116	$80,404

As described in Note 2, Regulatory Matters, Alagasco’s rates are established under the RSE rate-setting process and are based on average equity for the period. Alagasco’s rates are not adjusted to exclude a return on its investment in regulatory assets during the recovery period.

15. TRANSACTIONS WITH RELATED PARTIES

The Company allocates certain corporate costs to Energen Resources and Alagasco based on the nature of the expense to be allocated using various factors including, but not limited to, total assets, earnings, or number of employees. The Company’s cash management program seeks to minimize borrowing from outside sources through inter-company lending. Under this program, Alagasco may borrow from but does not lend to affiliates. Alagasco had net trade receivables from affiliates of $4.7 million and $5.7 million at December 31, 2013 and 2012, respectively. Interest income and expense between affiliates is calculated monthly based on the market weighted average interest rate. Alagasco had $18,000 in affiliated company interest revenue during the year ended December 31, 2013. Alagasco had $0.3 million and $0.4 million in affiliated company interest expense during the years ended December 31, 2012 and 2011, respectively.

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16. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The following table provides changes in the components of accumulated other comprehensive income (loss), net of the related income tax effects.

(in thousands)	Cash Flow Hedges	Pension and Postretirement Plans	Total
Balance as of December 31, 2012	$44,196	$(52,507)	$(8,311)
Other comprehensive income (loss) before reclassifications	(11,014)	11,582	568
Amounts reclassified from accumulated other comprehensive income (loss)	(21,004)	8,680	(12,324)
Change in accumulated other comprehensive income (loss)	(32,018)	20,262	(11,756)
Balance as of December 31, 2013	$12,178	$(32,245)	$(20,067)

The following table provides details of the reclassifications out of accumulated other comprehensive income (loss).

(in thousands)	Year ended December 31, 2013 Amounts Reclassified	Line Item Where Presented
Gains and (losses) on cash flow hedges:		
Commodity contracts	$35,684	Operating revenues
Interest rate swap	(1,723)	Interest expense
Total cash flow hedges	33,961	
Income tax expense	(12,957)	
Net of tax	21,004	
Pension and postretirement plans:		
Transition obligation	(319)	Operations and maintenance
Prior service cost	(257)	Operations and maintenance
Actuarial losses*	(12,357)	Operations and maintenance
Actuarial losses on settlement charges*	(421)	Regulatory asset
Total pension and postretirement plans	(13,354)	
Income tax expense	4,674	
Net of tax	(8,680)	
Total reclassifications for the period	$12,324	

* In the first quarter of 2013, the Company incurred a settlement charge of $0.5 million for the payment of lump sums from the nonqualified supplemental retirement plans, of which $0.1 million is recognized in actuarial losses above and $0.4 million is recognized as a regulatory asset at Alagasco and reported in actuarial losses on settlement charges above. In the third quarter of 2013, the Company incurred a settlement charge of $64,000 for the payment of lump sums from the nonqualified supplemental retirement plans, of which $18,000 is recognized in actuarial losses above and $46,000 is recognized as a regulatory asset at Alagasco and reported in actuarial losses on settlement charges above.

17. RECENTLY ISSUED ACCOUNTING STANDARDS

In December 2011, the FASB issued Accounting Standard Update (ASU) No. 2011-11, Disclosures about Offsetting Assets and Liabilities. The amendments in this update require an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. The amendment is effective for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. In January 2013, the FASB issued Accounting Standard Update (ASU) No. 2013-01, Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities. The effective date and transition of the disclosure requirement in ASU No. 2011-11 remained

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unchanged. The adoption of this standard did not have a material impact on the consolidated financial statements of the Company. The additional disclosures are included in Note 8, Financial Instruments.

In February 2013, the FASB issued ASU No. 2013-02, Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income. This update requires companies to include reclassification adjustments for items that are reclassified from other comprehensive income to net income in a single note or on the face of the financial statements. The amendment was effective for annual and interim reporting periods beginning after December 15, 2012. The adoption of this standard did not have a material impact on the consolidated financial statements of the Company. The additional disclosures are included in Note 16, Accumulated Other Comprehensive Income (Loss).

18. SUMMARIZED QUARTERLY FINANCIAL DATA (Unaudited)

The Company's business is seasonal in character. The following data summarizes quarterly operating results.

	Year ended December 31, 2013			
(in thousands, except per share amounts)	First	Second	Third	Fourth
Operating revenues as originally reported	$492,679	$490,057	$320,406	$472,733
Discontinued operations*	(18,663)	(18,562)	—	—
Adjusted operating revenues	$474,016	$471,495	$320,406	$472,733
Operating income (loss) as originally reported	$105,336	$146,304	$(4,052)	$110,630
Discontinued operations*	(3,146)	(3,871)	—	—
Adjusted operating income (loss)	$102,190	$142,433	$(4,052)	$110,630
Income (loss) from continuing operations	$54,694	$80,614	$(5,486)	$63,325
Net income (loss)	$56,692	$83,067	$(19,298)	$84,093
Diluted earnings per average common share				
Continuing operations	$0.76	$1.11	$(0.08)	$0.87
Net income (loss)	$0.78	$1.15	$(0.27)	$1.15
Basic earnings per average common share				
Continuing operations	$0.76	$1.12	$(0.08)	$0.87
Net income (loss)	$0.79	$1.15	$(0.27)	$1.16

* As discussed in Note 13, Discontinued Operations, during the fourth quarter of 2013, the Company completed the sale of its Black Warrior Basin coalbed methane properties in Alabama. The property was classified as held-for-sale and reflected in discontinued operations during the third quarter of 2013. Also, during the third quarter of 2013, the Company classified its North Louisiana/East Texas natural gas and oil properties as held-for-sale and reflected the associated operating results in discontinued operations.

	Year ended December 31, 2012			
(in thousands, except per share amounts)	First	Second	Third	Fourth
Operating revenues as originally reported	$418,444	$470,355	$295,324	$433,046
Discontinued operations	(20,255)	(18,451)	(18,895)	(18,749)
Adjusted operating revenues	$398,189	$451,904	$276,429	$414,297
Operating income as originally reported	$104,170	$220,598	$19,458	$115,166
Discontinued operations	16,324	(4,751)	(5,494)	(3,557)
Adjusted operating income	$120,494	$215,847	$13,964	$111,609
Income (loss) from continuing operations	$67,868	$128,305	$(1,505)	$60,552
Net income	$57,406	$131,287	$2,046	$62,823
Diluted earnings per average common share				
Continuing operations	$0.94	$1.77	$(0.02)	$0.84
Net income	$0.79	$1.82	$0.03	$0.87
Basic earnings per average common share				
Continuing operations	$0.94	$1.78	$(0.02)	$0.84
Net income	$0.80	$1.82	$0.03	$0.87

Alagasco’s business is seasonal in character and influenced by weather conditions. The following data summarizes Alagasco’s quarterly operating results.

	Year ended December 31, 2013			
(in thousands)	First	Second	Third	Fourth
Operating revenues	$237,685	$104,514	$48,368	$142,771
Operating income (loss)	$79,293	$2,219	$(22,544)	$34,800
Net income (loss)	$47,222	$(704)	$(8,961)	$19,842

	Year ended December 31, 2012			
(in thousands)	First	Second	Third	Fourth
Operating revenues	$194,487	$70,887	$61,809	$124,406
Operating income (loss)	$78,560	$4,448	$(12,743)	$22,951
Net income (loss)	$46,918	$326	$(10,039)	$12,197

19. OIL AND GAS OPERATIONS (Unaudited)

Capitalized Costs: The following table sets forth capitalized costs:

(in thousands)	December 31, 2013	December 31, 2012
Proved	$7,043,779	$6,241,148
Unproved	168,975	197,979
Total capitalized costs	7,212,754	6,439,127
Accumulated depreciation, depletion and amortization	2,078,411	1,765,241
Capitalized costs, net	$5,134,343	$4,673,886

Costs Incurred: The following table sets forth costs incurred in property acquisition, exploration and development activities and includes both capitalized costs and costs charged to expense during the year:

Years ended December 31, (in thousands)	2013	2012	2011
Property acquisition:			
Proved	$4,661	$79,862	$214,993
Unproved	26,820	58,634	91,888
Exploration	435,636	419,284	190,854
Development	655,353	749,256	623,775
Total costs incurred	$1,122,470	$1,307,036	$1,121,510

Results of Operations From Producing Activities: The following table sets forth results of the Company's oil and gas operations from producing activities:

Years ended December 31, (in thousands)	2013	2012	2011
Gross revenues*	$1,206,293	$1,090,948	$834,700
Production (lifting costs)	351,541	278,193	226,361
Exploration expense	27,942	19,356	12,967
Depreciation, depletion and amortization	449,700	339,569	210,532
Accretion expense	6,995	6,339	5,699
Income tax expense	128,773	160,551	134,564
Results of operations from producing activities	$241,342	$286,940	$244,577

* The years ended December 31, 2013, 2012 and 2011 gross revenues include a pre-tax non-cash mark-to-market loss on derivatives of $47.8 million, a pre-tax non-cash mark-to-market gain on derivatives of $58.8 million and a pre-tax non-cash mark-to-market loss on derivatives of $37.6 million, respectively.

Oil and Gas Operations: The calculation of proved reserves is made pursuant to rules prescribed by the SEC. Such rules, in part, require that proved categories of reserves be disclosed. Reserves and associated values were calculated using twelve-month average prices and current costs for the years ended December 31, 2013, 2012 and 2011. Changes to prices and costs could have a significant effect on the disclosed amount of reserves and their associated values. In addition, the estimation of reserves inherently requires the use of geologic and engineering estimates which are subject to revision as reservoirs are produced and developed and as additional information is available. Accordingly, the amount of actual future production may vary significantly from the amount of reserves disclosed. The proved reserves are located onshore in the United States of America.

Estimates of physical quantities of oil and gas proved reserves were determined by Company engineers. Ryder Scott Company, L.P. (Ryder Scott) and T. Scott Hickman and Associates, Inc. (T. Scott Hickman), independent oil and gas reservoir engineers, have audited the estimates of proved reserves of natural gas, oil and natural gas liquids that the Company has attributed to its net interests in oil and gas properties as of December 31, 2013. Ryder Scott audited the reserve estimates for coalbed methane in the San Juan basins and substantially all of the Permian Basin reserves. T. Scott Hickman audited the reserves for the North Louisiana and East Texas regions and the conventional reserves in the San Juan Basin. The independent reservoir engineers have issued reports covering approximately 98 percent of the Company's ending proved reserves indicating that in their judgment the estimates are reasonable in the aggregate.

Year ended December 31, 2013	Gas MMcf	Oil MBbl	NGL MBbl	Total MMBOE
Proved reserves at beginning of period	809,128	155,348	56,155	346.4
Revisions of previous estimates	18,465	(680)	2,211	4.6
Purchases	282	142	56	0.2
Extensions and discoveries	50,568	20,517	7,823	36.8
Production	(70,506)	(10,378)	(3,233)	(25.4)
Sales	(88,212)	(79)	(1)	(14.8)
Proved reserves at end of period	719,725	164,870	63,011	347.8
Proved developed reserves at end of period	623,305	113,795	42,087	259.8
Proved undeveloped reserves at end of period	96,420	51,075	20,924	88.0
Year ended December 31, 2012	Gas MMcf	Oil MBbl	NGL MBbl	Total MMBOE
Proved reserves at beginning of period	957,368	129,578	53,957	343.1
Revisions of previous estimates	(143,704)	(8,546)	(9,557)	(42.1)
Purchases	10,656	7,950	2,569	12.4
Extensions and discoveries	61,170	35,132	11,759	57.1
Production	(76,362)	(8,766)	(2,573)	(24.1)
Proved reserves at end of period	809,128	155,348	56,155	346.4
Proved developed reserves at end of period	708,657	105,976	36,440	260.5
Proved undeveloped reserves at end of period	100,471	49,372	19,715	85.9
Year ended December 31, 2011	Gas MMcf	Oil MBbl	NGL MBbl	Total MMBOE
Proved reserves at beginning of period	954,387	103,262	40,601	302.9
Revisions of previous estimates	(12,823)	(4,513)	841	(5.8)
Purchases	19,362	12,583	5,055	20.8
Extensions and discoveries	68,160	24,564	9,637	45.6
Production	(71,718)	(6,318)	(2,177)	(20.4)
Proved reserves at end of period	957,368	129,578	53,957	343.1
Proved developed reserves at end of period	788,812	83,899	33,154	248.5
Proved undeveloped reserves at end of period	168,556	45,679	20,803	94.6

2013 Activities: Energen Resources had upward reserve revisions during 2013 which totaled 4.6 MMBOE including approximately 7 MMBOE related to changes in year-end pricing and downward revisions of approximately 5.3 MMBOE of proved undeveloped reserves of which 4.6 MMBOE are expected to be drilled beyond five years with the remainder no longer expected to be drilled. The San Juan Basin upward reserve revisions of 2.2 MMBOE including 5.9 MMBOE related to changes in year-end pricing and downward revisions of approximately 4.6 MMBOE of proved undeveloped reserves that are expected to be drilled beyond five years. Net upward reserve revisions of 1.2 MMBOE in the Permian Basin were due to improved well performance in certain Wolfberry wells and approximately 0.4 MMBOE related to changes in the year-end pricing and downward revisions of approximately 0.7 MMBOE of proved undeveloped reserves that are no longer expected to be drilled.

Energen Resources purchased 0.2 MMBOE of reserves during 2013 primarily related to the acquisitions of oil properties in the Permian Basin.

During 2013, Energen Resources had extensions and discoveries of 36.8 MMBOE of which 45 percent were proved undeveloped reserves and 55 percent were proved developed reserves. Extension drilling resulted in 21.6 MMBOE of discoveries with exploratory drilling providing 15.2 MMBOE of discoveries. The San Juan Basin added 2.3 MMBOE of reserves through 30 pay adds. The Permian Basin added 34.4 MMBOE of reserves primarily through the drilling or identification of 262 well locations.

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During 2013, Energen Resources had sales of 14.8 MMBOE primarily due to the sale of the Black Warrior Basin coalbed methane properties.

2012 Activities: Energen Resources had downward reserve revisions during 2012 which totaled 42.1 MMBOE. The Black Warrior Basin had downward reserve revisions totaling 5.1 MMBOE of which approximately 5.9 MMBOE related to estimated negative price related revisions partially offset by better well performance. The San Juan Basin downward reserve revisions of 19.7 MMBOE included 22.5 MMBOE in negative price related revisions partially offset by better well performance, lower operating costs and lower fuel usage. Downward reserve revisions of 15.8 MMBOE in the Permian Basin were primarily due to lower than anticipated performance in certain development wells along with 1.0 MMBOE of estimated negative price related revisions.

Energen Resources purchased 12.4 MMBOE of reserves during 2012 primarily related to the acquisitions of oil properties in the Permian Basin.

During 2012, Energen Resources had extensions and discoveries of 57.1 MMBOE of which 59 percent were proved undeveloped reserves and 41 percent were proved developed reserves. Extension drilling resulted in 45.6 MMBOE of discoveries with exploratory drilling providing 11.5 MMBOE of discoveries. The San Juan Basin added 0.9 MMBOE of reserves through the drilling or identification of 6 well locations. The Permian Basin added 56.1 MMBOE of reserves primarily through the drilling or identification of 422 well locations.

2011 Activities: Energen Resources had downward reserve revisions during 2011 which totaled 5.8 MMBOE. The Black Warrior Basin had downward reserve revisions totaling 0.3 MMBOE of which approximately 0.7 MMBOE related to estimated negative price related revisions partially offset by other positive revisions of 0.4 MMBOE. The San Juan Basin downward reserve revisions of 2.6 MMBOE included 3.9 MMBOE in negative performance related revisions partially offset by 1.3 MMBOE related to estimated positive price related revisions. Downward reserve revisions of 3.1 MMBOE in the Permian Basin were primarily due to lower than anticipated injection response in certain waterflood units and other performance related adjustments. These downward revisions were partially offset by 1.4 MMBOE of estimated positive price related revisions.

Energen Resources purchased 20.8 MMBOE of reserves during 2011 primarily related to the acquisitions of oil properties in the Permian Basin.

During 2011, Energen Resources had extensions and discoveries of 45.6 MMBOE of which 69 percent were proved undeveloped reserves and 31 percent were proved developed reserves. Extension drilling resulted in 41.1 MMBOE of discoveries with exploratory drilling providing 4.5 MMBOE of discoveries. The San Juan Basin added 5.9 MMBOE of reserves through the drilling or identification of 53 well locations. The Permian Basin added 39.6 MMBOE of reserves primarily through the drilling or identification of 395 well locations.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves: The standardized measure of discounted future net cash flows is not intended, nor should it be interpreted, to present the fair market value of the Company’s crude oil and natural gas reserves. An estimate of fair market value would take into consideration factors such as, but not limited to, the recovery of reserves not presently classified as proved reserves, anticipated future changes in prices and costs, and a discount factor more representative of the time value of money and the risks inherent in reserve estimates. At December 31, 2013, 2012 and 2011, the Company had a deferred hedging gain of $21.6 million, a deferred hedging gain of $74.8 million and a deferred hedging gain of $15 million, respectively, all of which are excluded from the calculation of standardized measure of future net cash flows.

Years ended December 31, (in thousands)	2013	2012	2011
Future gross revenues	$19,509,305	$17,735,363	$18,196,229

Future production costs	6,136,709	5,715,248	5,823,395
Future development costs	1,896,602	1,892,600	1,539,072
Future income tax expense	3,209,697	2,809,411	3,326,382
Future net cash flows	8,266,297	7,318,104	7,507,380
Discount at 10% per annum	4,248,456	3,618,785	3,878,217
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$4,017,841	$3,699,319	$3,629,163

The following are the principal sources of changes in the standardized measure of discounted future net cash flows:

Years ended December 31, (in thousands)	2013	2012	2011
Balance at beginning of year	$3,699,319	$3,629,163	$2,467,136
Revisions to reserves proved in prior years:			
Net changes in prices, production costs and future development costs	566,838	(922,792)	707,411
Net changes due to revisions in quantity estimates	(81,762)	(383,755)	(80,004)
Development costs incurred, previously estimated	299,432	472,603	392,720
Accretion of discount	369,932	362,916	246,714
Changes in timing and other	(179,502)	(317,244)	(25,937)
Total revisions	974,938	(788,272)	1,240,904
New field discoveries and extensions, net of future production and development costs	376,326	1,025,419	755,977
Sales of oil and gas produced, net of production costs	(1,014,593)	(812,781)	(763,171)
Purchases	4,690	189,755	232,768
Sales	(24,876)	—	—
Net change in income taxes	2,037	456,035	(304,451)
Net change in standardized measure of discounted future net cash flows	318,522	70,156	1,162,027
Balance at end of year	$4,017,841	$3,699,319	$3,629,163

20. INDUSTRY SEGMENT INFORMATION

The Company is principally engaged in two business segments: the development, exploration and production of oil and gas in the continental United States (oil and gas operations) and the purchase, distribution and sale of natural gas in central and north Alabama (natural gas distribution). The accounting policies of the segments are the same as those described in Note 1, Summary of Significant Accounting Policies.

Years ended December 31,(in thousands)	2013	2012	2011
Operating revenues from continuing operations			
Oil and gas operations	$1,205,312	$1,089,230	$838,160
Natural gas distribution	533,338	451,589	534,953
Total	$1,738,650	$1,540,819	$1,373,113
Operating income (loss) from continuing operations			
Oil and gas operations	$257,963	$369,765	$308,561
Natural gas distribution	93,768	93,216	86,216
Eliminations and corporate expenses	(530)	(1,067)	(1,078)
Total	$351,201	$461,914	$393,699
Depreciation, depletion and amortization expense from continuing operations			
Oil and gas operations	$453,474	$343,183	$213,841
Natural gas distribution	43,907	42,270	39,916
Total	$497,381	$385,453	$253,757
Interest expense			
Oil and gas operations	$53,981	$49,958	$30,907
Natural gas distribution	15,649	16,284	14,740
Eliminations and other	(430)	(700)	(825)
Total	$69,200	$65,542	$44,822
Income tax expense (benefit) from continuing operations			
Oil and gas operations	$71,290	$115,090	$100,700
Natural gas distribution	34,687	30,244	26,670
Other	(695)	(800)	(1,048)
Total	$105,282	$144,534	$126,322
Capital expenditures			
Oil and gas operations	$1,104,745	$1,291,211	$1,115,452
Natural gas distribution	88,769	71,869	73,984
Total	$1,193,514	$1,363,080	$1,189,436
Identifiable assets			
Oil and gas operations	$5,379,135	$4,975,170	$4,046,242
Natural gas distribution	1,193,413	1,177,134	1,163,959
Eliminations and other	49,664	23,586	27,215
Total	$6,622,212	$6,175,890	$5,237,416
Property, plant and equipment, net			
Oil and gas operations	$5,116,958	$4,697,683	$3,806,787
Natural gas distribution	885,550	842,685	813,471
Other	1,130	1,268	518
Total	$6,003,638	$5,541,636	$4,620,776

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS

Energen Corporation

Years ended December 31, (in thousands)	2013	2012	2011
ALLOWANCE FOR DOUBTFUL ACCOUNTS			
Balance at beginning of year	$6,549	$12,946	$15,048
Additions:			
Charged to income	2,244	1,415	4,269
Recoveries and adjustments	(1,463)	(1,262)	(1,744)
Net additions	781	153	2,525
Less uncollectible accounts written off	(1,636)	(6,550)	(4,627)
Balance at end of year	$5,694	$6,549	$12,946

Alabama Gas Corporation

Years ended December 31, (in thousands)	2013	2012	2011
ALLOWANCE FOR DOUBTFUL ACCOUNTS			
Balance at beginning of year	$5,700	$12,100	$14,200
Additions:			
Charged to income	2,243	1,409	4,202
Recoveries and adjustments	(1,469)	(1,263)	(1,745)
Net additions	774	146	2,457
Less uncollectible accounts written off	(1,474)	(6,546)	(4,557)
Balance at end of year	$5,000	$5,700	$12,100

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

None

ITEM 9A. CONTROLS AND PROCEDURES

Energen Corporation
a. Disclosure Controls and Procedures

Our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934) are designed to provide reasonable assurance of achieving their objectives and, as of the end of the period covered by this report, our chief executive officer and chief financial officer concluded that our disclosure controls and procedures are effective at that reasonable assurance level.

b. Management's Report on Internal Control Over Financial Reporting

Management of Energen Corporation is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Energen Corporation'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 accounting principles generally accepted in the United States of America. Internal control over financial reporting includes those written 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 Energen Corporation;

ii provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of Energen Corporation are being made only in accordance with authorization of management and directors of Energen Corporation; and

iii provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of assets that could have a material effect on the consolidated 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.

Management assessed the effectiveness of Energen Corporation's internal control over financial reporting as of December 31, 2013. Management based this assessment on criteria for effective internal control over financial reporting described in "Internal Control - Integrated Framework" (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management's assessment included an evaluation of the design of Energen Corporation's internal control over financial reporting and testing of the operational effectiveness of its internal control over financial reporting. Management reviewed the results of its assessment with the Audit Committee of our Board of Directors.

Based on this assessment, management determined that, as of December 31, 2013, Energen Corporation maintained effective internal control over financial reporting. The effectiveness of Energen Corporation's 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.

c. Changes in Internal Control Over Financial Reporting

Our chief executive officer and chief financial officer of Energen Corporation have concluded that during the most recent fiscal quarter covered by this report there were no changes in our internal control over financial reporting that materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Alabama Gas Corporation
a. Disclosure Controls and Procedures

Our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934) are designed to provide reasonable assurance of achieving their objectives and, as of the end of the period covered by this report, our chief executive officer and chief financial officer concluded that our disclosure controls and procedures are effective at that reasonable assurance level.

b. Management's Report on Internal Control Over Financial Reporting

Management of Alabama Gas Corporation is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Alabama Gas Corporation'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 accounting principles generally accepted in the United States of America. Internal control over financial reporting includes those written 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 Alabama Gas Corporation;
ii provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of Alabama Gas Corporation are being made only in accordance with authorization of management and directors of Alabama Gas Corporation; and
iii provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of assets that could have a material effect on the consolidated 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.

Management assessed the effectiveness of Alabama Gas Corporation's internal control over financial reporting as of December 31, 2013. Management based this assessment on criteria for effective internal control over financial reporting described in "Internal Control - Integrated Framework" (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management's assessment included an evaluation of the design of Alabama Gas Corporation's internal control over financial reporting and testing of the operational effectiveness of its internal control over financial reporting. Management reviewed the results of its assessment with the Audit Committee of our Board of Directors.

Based on this assessment, management determined that, as of December 31, 2013, Alabama Gas Corporation maintained effective internal control over financial reporting. The effectiveness of Alabama Gas Corporation's 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.

c. Remediation of Material Weakness

Alabama Gas Corporation disclosed in Item 4. Controls and Procedures of our Quarterly Report on Form 10-Q, for the quarter ended September 30, 2013, that we identified a material weakness in our internal control over financial reporting related to failure by Alabama Gas Corporation's principal accounting officer to operate within the Company's code of conduct. 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 our annual or interim financial statements will not be prevented or detected on a timely basis. Due to this weakness, certain controls were overridden resulting in an immaterial understatement of expenses for the quarter ended June 30, 2013 of approximately $76,000. Since the override was identified by management prior to preparation of financial statements for the quarter ended September 30, 2013, it did not result in misstatement for that quarter.

Management, with the participation of the chief executive officer and chief financial officer, took action to remediate the material weakness described above including the following:

- The principal accounting officer who overrode the control has separated from Alabama Gas Corporation

- A qualified successor principal accounting officer has been elected by the Alabama Gas Corporation Board of Directors
- In addition to an ongoing annual training process, the importance of adherence to Alabama Gas Corporation's statement of principles and business conduct guidelines as well as compliance with applicable accounting and reporting principles was reviewed and reinforced with key accounting personnel
- The importance of timely, complete and accurate recording of expenses was reviewed and reinforced with the Alabama Gas Corporation officers

Management has completed the remediation measures described above and, as of December 31, 2013, has concluded that the steps taken have remediated the material weakness.

d. Changes in Internal Control Over Financial Reporting

As described above under "Remediation of Material Weakness", there was a change, during the most recent fiscal quarter, in our internal control over financial reporting that materially affected our internal control over financial reporting.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information regarding the executive officers of Energen is included in Part I. The other information required by Item 10 is incorporated herein by reference from Energen's definitive proxy statement for the Annual Meeting of Shareholders to be held April 23, 2014. The definitive proxy statement will be filed on or about March 21, 2014.

ITEM 11. EXECUTIVE COMPENSATION

The information regarding executive compensation is incorporated herein by reference from Energen's definitive proxy statement for the Annual Meeting of Shareholders to be held April 23, 2014.

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

a. Security Ownership of Certain Beneficial Owners

The information regarding the security ownership of the beneficial owners of more than five percent of Energen's common stock is incorporated herein by reference from Energen's definitive proxy statement for the Annual Meeting of Shareholders to be held April 23, 2014.

b. Security Ownership of Management

The information regarding the security ownership of management is incorporated herein by reference from Energen's definitive proxy statement for the Annual Meeting of Shareholders to be held April 23, 2014.

c. Securities Authorized for Issuance Under Equity Compensation Plans

The following table summarizes information concerning securities authorized for issuance under equity compensation plans as of December 31, 2013:

Plan Category	Number of Securities to be Issued for Outstanding Options and Performance Share Awards	Weighted Average Exercise Price	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans
Equity compensation plans approved by security holders*	1,191,044	$51.06	3,754,816
Equity compensation plans not approved by security holders	—	—	—
Total	1,191,044	$51.06	3,754,816

* These plans include 2,921,392 shares associated with the Company's Stock Incentive Plan, 138,284 shares associated with the 1992 Energen Corporation Directors Stock Plan and 695,140 shares associated with the 1997 Deferred Compensation Plan.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information regarding certain relationships and related transactions, and director independence is incorporated herein by reference from Energen's definitive proxy statement for the Annual Meeting of Shareholders to be held April 23, 2014.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information regarding Principal Accountant Fees and Services is incorporated herein by reference from Energen's definitive proxy statement for the Annual Meeting of Shareholders to be held April 23, 2014.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

a. Documents Filed as Part of This Report

(1) Financial Statements
The consolidated financial statements of Energen and the financial statements of Alagasco are included in Item 8 of this Form 10-K.

(2) Financial Statement Schedules
The financial statement schedules are included in Item 8 of this Form 10-K.

(3) Exhibits
The exhibits listed on the accompanying Index to Exhibits are filed as part of this Form 10-K.

Energen Corporation
Alabama Gas Corporation
INDEX TO EXHIBITS
Item 14(a)(3)

Exhibit Number	Description
*3(a)	Restated Certificate of Incorporation of Energen Corporation (composite, as amended April 29, 2005) which was filed as Exhibit 3(a) to Energen's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2005
*3(b)	Articles of Amendment to Restated Certificate of Incorporation of Energen, designating Series 1998 Junior Participating Preferred Stock (July 27, 1998) which was filed as Exhibit 4(b) to Energen's Post Effective Amendment No. 1 to Registration Statement on Form S-3 (Registration No. 333-00395)
*3(c)	Bylaws of Energen Corporation (as amended through July 23, 2008) which was filed as Exhibit 99.1 to Energen's Current Report on Form 8-K, dated July 25, 2008
*3(d)	Articles of Amendment and Restatement of the Articles of Incorporation of Alabama Gas Corporation, dated September 27, 1995, which was filed as Exhibit 3(i) to the Registrant's Annual Report on Form 10-K for the year ended September 30, 1995
*3(e)	Bylaws of Alabama Gas Corporation (as amended through October 24, 2007) which was filed as Exhibit 3 to Energen's Quarterly Report on Form 10-Q for the period ended October 31, 2007
*4(a)	Form of Indenture between Energen Corporation and The Bank of New York, as Trustee, which was dated as of September 1, 1996 (the "Energen 1996 Indenture"), and which was filed as Exhibit 4(i) to the Registrant's Registration Statement on Form S-3 (Registration No. 333-11239)
*4(a)(i)	Officers' Certificate, dated September 13, 1996, pursuant to Section 301 of the Energen 1996 Indenture setting forth the terms of the Series A Notes which was filed as Exhibit 4(d)(i) to Energen's Annual Report on Form 10-K for the year ended September 30, 2001
*4(a)(ii)	Officers' Certificate, dated July 8, 1997, pursuant to Section 301 of the Energen 1996 Indenture amending the terms of the Series A Notes which was filed as Exhibit 4(d)(ii) to Energen's Annual Report on Form 10-K for the year ended September 30, 2001
*4(a)(iii)	Amended and Restated Officers' Certificate, dated February 27, 1998, setting forth the terms of the Series B Notes which was filed as Exhibit 4(d)(iii) to Energen's Annual Report on Form 10-K for the year ended September 30, 2001
*4(a)(iv)	Officers' Certificate, dated August 5, 2011, pursuant to Section 301 of the Energen 1996 Indenture setting forth the terms of the 4.65 percent Senior Notes due September 1, 2021, which was filed as Exhibit 4.1 to Energen's Current Report on Form 8-K, dated August 5, 2011
*4(b)	Indenture dated as of November 1, 1993, between Alabama Gas Corporation and NationsBank of Georgia, National Association, Trustee, ("Alagasco 1993 Indenture"), which was filed as Exhibit 4(k) to Alabama Gas Corporations' Registration Statement on Form S-3 (Registration No. 33-70466)

*4(b)(i)	Officers' Certificate, dated January 14, 2005, pursuant to Section 301 of the Alabama Gas Corporation 1993 Indenture setting forth the terms of the 5.70 percent Notes due January 15, 2035, which was filed as Exhibit 4.3 to Alabama Gas Corporations' Current Report on Form 8-K filed January 14, 2005
*4(b)(ii)	Officers' Certificate, dated January 14, 2005, pursuant to Section 301 of the Alabama Gas Corporation 1993 Indenture setting forth the terms of the 5.20 percent Notes due January 15, 2020, which was filed as Exhibit 4.4 to Alabama Gas Corporations' Current Report on Form 8-K filed January 14, 2005

*4(b)(iii)	Officers' Certificate, dated November 17, 2005, pursuant to Section 301 of the Alabama Gas Corporation 1993 Indenture setting forth the terms of the 5.368 percent Notes due December 1, 2015, which was filed as Exhibit 4.2 to Alabama Gas Corporations' Current Report on Form 8-K filed November 17, 2005
*4(b)(iv)	Officers' Certificate, dated January 16, 2007, pursuant to Section 301 of the Alabama Gas Corporation 1993 Indenture setting forth the terms of the 5.90 percent Notes due January 15, 2037, which was filed as Exhibit 4.2 to Alabama Gas Corporations' Current Report on Form 8-K filed January 16, 2007
*10(a)	Credit Agreement dated October 30, 2012, by and among Energen Corporation, Energen Resources Corporation, Bank of America, N.A., as Administrative Agent, Swing Line Lender and an L/C Issuer, Wells Fargo Bank, National Association and Regions Bank, and Co-Syndication Agents and L/C Issuers, Compass Bank and U.S. Bank National Association, as Co-Documentation Agents and L/C Issuers, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Wells Fargo Securities LLC, Regions Capital Markets, a division of Regions Bank, Compass Bank and U.S. Bank National Association, as Joint Lead Arrangers and Joint Book Managers, and the lenders party thereto which was filed as Exhibit 10.1 to Energen's Current Report on Form 8-K filed October 31, 2012
*10(b)	Credit Agreement dated December 17, 2013, with respect to a $600 million term loan, by and among Energen Corporation, as Borrower, Energen Resources Corporation, as Guarantor, Bank of America, N.A., as Administrative Agent, Wells Fargo Bank, National Association, Regions Bank, Compass Bank, JPMorgan Chase Bank, N.A. and U.S. Bank National Association, as Co-Syndication Agents, and the lenders party thereto, which was filed as Exhibit 10.1 to Energen's Current Report on Form 8-K filed December 19, 2013
*10(c)	Credit Agreement dated October 30, 2012, by and among Alabama Gas Corporation, Bank of America, N.A., as Administrative Agent, Swing Line Lender and an L/C Issuer, Wells Fargo Bank, National Association and Regions Bank, and Co-Syndication Agents and L/C Issuers, Compass Bank and U.S. Bank National Association, as Co-Documentation Agents and L/C Issuers, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Wells Fargo Securities LLC, Regions Capital Markets, a division of Regions Bank, Compass Bank and U.S. Bank National Association, as Joint Lead Arrangers and Joint Book Managers, and the lenders party thereto which was filed as Exhibit 10.2 to Energen's Current Report on Form 8-K filed October 31, 2012
*10(d)	Note Purchase Agreement, dated December 22, 2011, among Alabama Gas Corporation and the Purchasers thereto (the AIG purchasers) with respect to $25 million 3.86 percent Senior Notes due December 22, 2021, which was filed as Exhibit 10.1 to Alabama Gas Corporation's Current Report on Form 8-K filed December 22, 2011
*10(e)	Note Purchase Agreement, dated December 22, 2011, among Alabama Gas Corporation and the Purchasers thereto (the Prudential purchasers) with respect to $25 million 3.86 percent Senior Notes due December 22, 2021, which was filed as Exhibit 10.2 to Alabama Gas Corporation's Current Report on Form 8-K filed December 22, 2011
*10(f)	Service Agreement Under Rate Schedule CSS (No. SSNG1), between Southern Natural Gas Company and Alabama Gas Corporation, dated as of September 1, 2005, which was filed as Exhibit 10(a) to Energen's Annual Report on Form 10-K for the year ended December 31, 2005
10(g)	Amended Exhibit A, effective January 15, 2014, to Service Agreement Under Rate Schedule CSS (No. SSNG1) between Southern Natural Gas Company and Alabama Gas Corporation dated September 1, 2005

*10(h)	Firm Transportation Service Agreement Under Rate Schedule FT and/or FT-NN (No. FSNG1), between Southern Natural Gas Company and Alabama Gas Corporation dated as of September 1, 2005, which was filed as Exhibit 10(b) to Energen's Annual Report on Form 10-K for the year ended December 31, 2005
10(i)	Amended Exhibit A, effective October 1, 2013, to Firm Transportation Service Agreement (No. FSNG1) between Southern Natural Gas Company and Alabama Gas Corporation
10(j)	Amended Exhibit B, effective November 1, 2013, to Firm Transportation Service Agreement (No. FSNG1) between Southern Natural Gas Company and Alabama Gas Corporation
*10(k)	Form of Service Agreement Under Rate Schedule IT (No. 790420), between Southern Natural Gas Company and Alabama Gas Corporation, which was filed as Exhibit 10(b) to Energen's Annual Report on Form 10-K for the year ended September 30, 1993

*10(l)	Service Agreement between Transcontinental Gas Pipeline Corporation and Transco Energy Marketing Company as Agent for Alabama Gas Corporation, dated August 1, 1991 which was filed as Exhibit 3(e) to Energen's Annual Report on Form 10-K for the year ended December 31, 2003
*10(m)	Amendment to Service Agreement between Transcontinental Gas Pipeline Corporation and Alabama Gas Corporation, dated December 2, 2005, which was filed as Exhibit 10(e) to Energen's Annual Report on Form 10-K for the year ended December 31, 2005
*10(n)	Form of Executive Retirement Supplement Agreement between Energen Corporation and its executive officers (as revised October 2000) which was filed as Exhibit 10(c) to Energen's Annual Report on Form 10-K for the year ended September 30, 2000
10(o)	Form of Amendment to Executive Retirement Supplement Agreement between Energen Corporation and its executive officers, dated December 12, 2007
*10(p)	Form of Severance Compensation Agreement between Energen Corporation and its executive officers which was filed as Exhibit 10.3 to Energen's Current Report on Form 8-K filed December 13, 2012
*10(q)	Energen Corporation Stock Incentive Plan (as amended effective December 11, 2013) which was filed as Exhibit 10.1 to Energen's Current Report on Form 8-K filed December 12, 2013
*10(r)	Form of Stock Option Agreement under the Energen Corporation Stock Incentive Plan which was filed as Exhibit 10(r) to Energen's Annual Report on Form 10-K for the year ended December 31, 2012
*10(s)	Form of Restricted Stock Agreement under the Energen Corporation Stock Incentive Plan which was filed as Exhibit 10(s) to Energen's Annual Report on Form 10-K for the year ended December 31, 2012
*10(t)	Form of Restricted Stock Unit Agreement under the Energen Corporation Stock Incentive Plan which was filed as Exhibit 10.2 to Energen's Current Report on Form 8-K filed December 12, 2013
*10(u)	Form of Performance Share Award under the Energen Corporation Stock Incentive Plan which was filed as Exhibit 10(t) to Energen's Annual Report on Form 10-K for the year ended December 31, 2012
*10(v)	Energen Corporation 1997 Deferred Compensation Plan (as amended December 12, 2012) which was filed as Exhibit 10(u) to Energen's Annual Report on Form 10-K for the year ended December 31, 2013
*10(w)	Energen Corporation Directors Stock Plan (as amended April 28, 2010) which was filed as an attachment to Energen's definitive Proxy Statement on Schedule 14A , filed March 19, 2010
*10(x)	Energen Corporation Annual Incentive Compensation Plan, as amended effective January 1, 2013, which was filed as Exhibit 10.1 to Energen's Current Report on Form 8-K, filed December 13, 2012
21	Subsidiaries of Energen Corporation and Alabama Gas Corporation
23(a)	Consent of Registered Public Accounting Firm (PricewaterhouseCoopers LLP)
23(b)	Consent of Independent Oil and Gas Reservoir Engineers (Ryder Scott Company, L.P.)
23(c)	Consent of Independent Oil and Gas Reservoir Engineers (T. Scott Hickman and Associates, Inc.)

24	Power of Attorney
31(a)	Energen Corporation Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a)
31(b)	Energen Corporation Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a)

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31(c)	Alabama Gas Corporation Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a)
31(d)	Alabama Gas Corporation Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a)
32(a)	Energen Corporation Certification pursuant to 18 U.S.C. Section 1350
32(b)	Alabama Gas Corporation Certification pursuant to 18 U.S.C. Section 1350
99(a)	Reserve Audit – Ryder Scott & Company, L.P.
99(b)	Reserve Audit – T. Scott Hickman and Associates, Inc.
101	The financial statements and notes thereto from Energen Corporation’s Annual Report on Form 10-K for the year ended December 31, 2013 are formatted in XBRL

*Incorporated by reference

SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities and Exchange Act of 1934, the Registrants have duly caused this report to be signed on their behalf by the undersigned thereunto duly authorized.

ENERGEN CORPORATION
(Registrant)

ALABAMA GAS CORPORATION
(Registrant)

March 3, 2014	By /s/ J.T. McManus, II J.T. McManus, II Chairman, Chief Executive Officer and President of Energen Corporation; Chairman and Chief Executive Officer of Alabama Gas Corporation; Director

SIGNATURES

Pursuant to the requirements of the Securities and Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrants and in the capacities and on the dates indicated:

March 3, 2014	By /s/ J.T. McManus, II J.T. McManus, II Chairman, Chief Executive Officer and President of Energen Corporation; Chairman and Chief Executive Officer of Alabama Gas Corporation; Director
March 3, 2014	By /s/ Charles W. Porter, Jr. Charles W. Porter, Jr. Vice President, Chief Financial Officer and Treasurer of Energen Corporation and Alabama Gas Corporation
March 3, 2014	By /s/ Russell E. Lynch, Jr. Russell E. Lynch, Jr. Vice President and Controller of Energen Corporation
March 3, 2014	By /s/ Leonarda M. DiChiara Leonarda M. DiChiara Vice President and Controller of Alabama Gas Corporation
March 3, 2014	* Kenneth W. Dewey Director
March 3, 2014	* Jay Grinney Director
March 3, 2014	* Frances Powell Hawes Director
March 3, 2014	* Judy M. Merritt Director
	*By /s/ Charles W. Porter, Jr. Charles W. Porter, Jr. Attorney-in-Fact