ALABAMA GAS CORP
Form 10-K
February 28, 2013

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, 2012

( ) 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, 2012:

Energen Corporation	$3,193,878,000

Indicate number of shares outstanding of each of the registrant's classes of common stock as of February 15, 2013:

Energen Corporation	72,222,552 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 27, 2013 (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.

ENERGEN CORPORATION
2012 FORM 10-K ANNUAL REPORT

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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 2012 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, based in Birmingham, Alabama, is a diversified energy holding company engaged in the development, acquisition, exploration and production 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, Governance and Nominations Committee Charter and Finance 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 18, 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 and acquisition 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, San Juan and Black Warrior 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 2012, Energen Resources' proved oil and gas reserves totaled 346.4 million barrels of oil equivalent (MMBOE). Substantially all of these reserves are located in the Permian Basin in west Texas, the San Juan Basin in New Mexico and Colorado and the Black Warrior Basin in Alabama. 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 14 years. Oil, natural gas and natural gas liquids represent approximately 45 percent, 39 percent and 16 percent, respectively, of Energen Resources' proved reserves.

Growth Strategy: Energen operates under a strategy to grow the oil and gas operations of Energen Resources largely through the acquisition and exploitation of proved and high-quality unproved reserves. The company traditionally prefers properties located onshore in North America that offer long-lived reserves and multiple pay-zone opportunities. Energen Resources also conducts exploration activities in and around the basins in which it operates; exploration in other areas is possible if the opportunities complement its core expertise and meet its investment requirements. Following an acquisition, 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 94 percent of its proved reserves at December 31, 2012.

Since the end of fiscal year 1995, Energen Resources has invested approximately $1.9 billion to acquire proved and unproved reserves, $3.7 billion in related development and $1.3 billion in exploration. Energen Resources' capital spending plans for 2013 target a total investment of approximately $905 million, the bulk of which will focus on drilling and related development activities on its existing properties, with approximately 98 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, 2012, the Company's development and exploratory efforts have added 130 MMBOE of proved reserves from the drilling of 1,300 gross development, exploratory and service wells (including 18 sidetrack wells) and 326 well recompletions and pay-adds. In 2012, Energen Resources' successful development and exploratory wells and other activities added approximately 57 MMBOE of proved reserves; the Company drilled 434 gross development, exploratory and service wells (including 3 sidetrack wells), performed some 116 well recompletions and pay-adds, and conducted other operational enhancements. Energen Resources' production totaled 24.1 MMBOE in 2012 and is estimated to total 26.1 MMBOE in 2013, including 24.9 MMBOE of estimated production from proved reserves owned at December 31, 2012.

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

Years ended December 31,	2012	2011	2010
Development:			
Productive	239.9	370.3	210.0
Dry	—	3.3	1.0
Total	239.9	373.6	211.0
Exploratory:			
Productive	74.1	23.3	3.4
Dry	1.1	1.0	5.0
Total	75.2	24.3	8.4

As of December 31, 2012, the Company was participating in the drilling of 8 gross development and 4 gross exploratory wells, with the Company's interest equivalent to 6.9 wells and 3.3 wells, respectively. In addition to the development wells drilled, the Company drilled 47.8, 29.1 and 39.8 net service wells during 2012, 2011 and 2010, respectively.

Productive Wells and Acreage: The following table sets forth the total gross and net productive gas and oil wells as of December 31, 2012, and developed and undeveloped acreage as of the latest practicable date prior to year-end:

	Gross	Net
Oil wells	4,531	2,988
Gas wells	4,402	2,413
Developed acreage	810,862	614,697
Undeveloped acreage	171,723	117,762

There were 10 wells with multiple completions in 2012. All wells and acreage are located onshore in the United States, with the majority of the net undeveloped acreage located in Texas and Colorado.

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. If a derivative is designated as a cash flow hedge, the effectiveness of the hedge, or the degree that the gain (loss) for the hedging instrument offsets the loss (gain) on the hedged item, is measured at each reporting period. The effective portion of the gain or loss on the derivative instrument is recognized in other comprehensive income as a component of equity and subsequently reclassified to operating revenues when the forecasted transaction affects earnings. The ineffective portion of a derivative's change in fair value is required to be recognized in operating revenues immediately.

The Company periodically enters into derivative transactions that do not qualify for cash flow hedge accounting but are considered by management to represent valid economic hedges and are accounted for as mark-to-market transactions. These economic hedges may include, but are not limited to, hedges on estimated future production not yet flowing, basis hedges without a corresponding New York Mercantile Exchange hedge, and hedges on non-operated or other properties for which all of the necessary information to qualify for cash flow hedge accounting is either not readily available or subject to change. Derivatives that do not qualify for hedge treatment or are not designated as cash flow hedges are recorded at fair value with gains or losses recognized in operating revenues in the period of change.

See the Forward-Looking Statements preceding Item I, 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 186 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 2012, Alagasco served an average of 393,467 residential customers and 31,450 commercial, industrial and transportation customers. The Alagasco distribution system includes approximately 11,298 miles of main and more than 11,899 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. RSE’s current extension is for a seven-year period ending December 31, 2014. RSE will continue after December 31, 2014, unless, after notice to the Company and a hearing, the APSC votes to modify or discontinue the RSE methodology. Alagasco is on a September 30 fiscal year for rate-setting purposes (rate year).

Alagasco's allowed range of return on average equity remains 13.15 percent to 13.65 percent throughout the term of the RSE order. 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. RSE limits the utility’s equity upon which a return is permitted to 55 percent of total capitalization, subject to certain adjustments. Under the inflation-based Cost Control Measurement (CCM) established by the APSC, if the percentage change in operations and maintenance (O&M) expense on an aggregate basis falls within a range of 0.75 points above or below the percentage change in the Consumer Price Index For All Urban Consumers (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 the Company 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 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 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, 2012, Alagasco had the following contracts in place for firm natural gas pipeline transportation and storage services:

	December 31, 2012 (Mcfd)
Southern firm transportation	112,933
Southern storage and no notice transportation	231,679
Transco firm transportation	70,000
Various intrastate transportation	20,216

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 2012, 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 2012 declined approximately 0.6 percent from 2011 and reflected a moderation in decline over the five-year trend. Other factors impacting Alagasco's average customer account include recent warmer weather, 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 1% by volume) that can vary by project. The carefully designed, 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.

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 and is the subject of a recent inquiry discussed below. Also discussed below is the recent completion of a removal action at the Huntsville, Alabama manufactured gas plant site. An investigation of the sites does not indicate the present need for other remediation activities and management expects that, should remediation of any such sites be required in the future, Alagasco's share, if any, of such costs will not materially affect the financial position of Alagasco.

In May 2012, Alagasco received from the United States Environmental Protection Agency (EPA) a Request for information Pursuant to Section 104 of CERCLA relating to the EPA's investigation of a site which it refers to as the 35th Avenue Superfund Site in and around Birmingham, Jefferson County, Alabama. The inquiry requests information about a parcel owned by Alagasco and located in the vicinity of the 35th Avenue site. The parcel is the former site of a manufactured gas distribution facility. Alagasco has responded to the inquiry.

In June 2009, Alagasco received a General Notice Letter from the EPA identifying Alagasco as a responsible party for a former manufactured gas plant (MGP) site located in Huntsville, Alabama, and inviting Alagasco to enter an Administrative Settlement Agreement and Order on Consent to perform a removal action at that site. The Huntsville MGP, along with the Huntsville gas distribution system, was sold by Alagasco to the City of Huntsville in 1949. While Alagasco no longer owns the Huntsville site, the Company and the current site owner entered into a Consent Order, and developed and completed during 2011 an action plan for the site. Alagasco has incurred costs associated with the site of approximately $5 million. As of December 31, 2012, the expected remaining costs are not expected to be material to the Company. Alagasco has recorded a corresponding amount, subject to APSC review guidelines, against the refundable negative salvage costs being refunded to customers.

• Employees

The Company has approximately 1,575 employees, of which Alagasco employs 1,087 and Energen Resources employs 488. 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 natural gas, oil 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 Company's credit rating 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 both lenders and the Company. 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 or limit availability of funds to the Company.

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 17, 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 acquisition and development of onshore North American oil and gas properties. Energen Resources maintains district offices in Midland, Texas; Farmington, New Mexico; Arcadia, Louisiana; and Brookwood, Alabama.

The major areas of operations include (1) the Permian Basin, (2) the San Juan Basin, (3) the Black Warrior Basin and (4) North Louisiana/East Texas as highlighted on the above map.

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

	Year ended December 31, 2012 Production Volumes (MBOE)	December 31, 2012 Proved Reserves (MBOE)	December 31, 2012 Reserves-to-Production Ratio
Permian Basin	11,198	225,006	20.09 years
San Juan Basin	9,921	100,910	10.17 years
Black Warrior Basin	2,120	16,165	7.63 years
North Louisiana/East Texas	763	3,394	4.45 years
Other	64	884	13.81 years
Total	24,066	346,359	14.39 years

The following table sets forth proved reserves by area as of December 31, 2012:

	Gas MMcf	Oil MBbl	NGL MBbl
Permian Basin	208,831	154,172	36,028
San Juan Basin	478,592	1,017	20,127
Black Warrior Basin	96,993	—	—
North Louisiana/East Texas	20,055	51	—
Other	4,657	108	—
Total	809,128	155,348	56,155

The following table sets forth proved developed reserves by area as of December 31, 2012:

	Gas MMcf	Oil MBbl	NGL MBbl
Permian Basin	127,443	104,825	17,725
San Juan Basin	459,509	992	18,715
Black Warrior Basin	96,993	—	—
North Louisiana/East Texas	20,055	51	—
Other	4,657	108	—
Total	708,657	105,976	36,440

The following table sets forth proved undeveloped reserves by area as of December 31, 2012:

	Gas MMcf	Oil MBbl	NGL MBbl
Permian Basin	81,388	49,347	18,303
San Juan Basin	19,083	25	1,412
Black Warrior Basin	—	—	—
North Louisiana/East Texas	—	—	—
Total	100,471	49,372	19,715

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

Year ended December 31, 2012	Total MMBOE
Balance at beginning of period	94.6
Undeveloped reserves transferred to developed reserves*	(24.6)
Revisions**	(28.2)
Acquisitions	10.2
Extensions and discoveries	33.9
Balance at end of period	85.9

* Reflects capital expenditures of approximately $443 million during the year ended December 31, 2012 in development of previously proved undeveloped reserves.
** The majority of the revisions relate to the five-year proved undeveloped reserve development rules (8.9 MMBOE) and to well performance (8.8 MMBOE).

Energen Resources files Form EIA-23 with the Department of Energy which reports gross proved reserves, including the working interest and royalty interest share of other owners, for properties operated by the Company. The proved reserves reported in the table above represent our share of proved reserves for all properties, based on our ownership interest in each property. For properties operated by Energen Resources, the difference between the gross proved reserves reported on Form EIA-23 and the gross reserves

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associated with the Company-owned net proved reserves reported in the table above does not exceed five percent. Estimated proved reserves as of December 31, 2012 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 generally used in the Petroleum 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 2012, approximately 99 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:

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

The following table sets forth the total net productive gas and oil wells by area as of December 31, 2012, 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	2,965	160,294	97,211
San Juan Basin	1,454	281,179	20,471
Black Warrior Basin	797	146,529	80
North Louisiana/East Texas	175	20,793	—
Other	10	5,902	—
Total	5,401	614,697	117,762

The net undeveloped acreage largely relates to the recent purchase of oil properties in the Permian Basin.

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 52 billion cubic feet (net) of natural gas through March 2014. The Company expects to fulfill delivery commitments through production of existing proved reserves.

	Gas MMcf
San Juan Basin	42,790
Black Warrior Basin	9,222
Total	52,012

Natural Gas Distribution

The properties of Alagasco consist primarily of its gas distribution system, which includes approximately 11,298 miles of main and more than 11,899 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.

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 specific relief. 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 Energen and its affiliates conduct business in Alabama and other jurisdictions in which the magnitude and frequency of punitive or other damage awards may bear little or no relation to culpability or actual damages, thus making it difficult to predict litigation results.

On November 2, 2011 Energen Resources spudded the Cadenhead 25-1 Well (the Cadenhead Well) in Ward County, Texas. During the drilling phase, Chesapeake Exploration, LLC, notified Energen Resources that it believed it was the owner of the lease from which the Cadenhead Well was producing. Shortly thereafter, Energen Resources filed a declaratory judgment action in the District Court of Ward County, Texas to resolve the title dispute. Energen Resources has a fifty percent working interest in the Cadenhead Well. The Cadenhead Well produced approximately 63 net MBOE in 2012 and is expected to produce approximately 42 net MBOE in 2013. On January 18, 2013, a judgment was entered which was adverse to Energen Resources' claim of ownership. The Company believes the adverse ruling was incorrect, and plans to vigorously pursue all available avenues of appeal.

Other

Various other pending or threatened legal proceedings are in progress currently, and the Company has accrued a provision for the estimated liability. See the 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	54	Chairman, Chief Executive Officer and President of Energen and Chairman and Chief Executive Officer of Alagasco (2)
Charles W. Porter, Jr.	48	Vice President, Chief Financial Officer and Treasurer of Energen and Alagasco (3)
John S. Richardson	55	President and Chief Operating Officer of Energen Resources (4)
Dudley C. Reynolds	59	President and Chief Operating Officer of Alagasco (5)
J. David Woodruff, Jr.	56	Vice President, General Counsel and Secretary of Energen and Alagasco (6)
Russell E. Lynch, Jr.	39	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 became Energen's Director of Financial Accounting in 2007. 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, 2011	63.83	48.62	63.12	0.135
June 30, 2011	65.44	53.79	56.50	0.135
September 30, 2011	62.50	38.84	40.89	0.135
December 31, 2011	53.24	37.22	50.00	0.135
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

Energen's common stock is listed on the New York Stock Exchange under the symbol EGN. On February 15, 2013, there were 5,467 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 $0.58 per share on the Company’s common stock in 2013. 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 securities authorized for issuance under equity compensation plans as of December 31, 2012:

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*	1,648,475	$47.58	4,288,140
Equity compensation plans not approved by security holders	—	—	—
Total	1,648,475	$47.58	4,288,140

* These plans include 3,418,881 shares associated with the Company’s Stock Incentive Plan, 162,904 shares associated with the 1992 Energen Corporation Directors Stock Plan and 706,355 shares associated with the 1997 Deferred Compensation Plan.

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, 2012 through October 31, 2012	943*	$51.55	—	8,992,700
November 1, 2012 through November 30, 2012	—	—	—	8,992,700
December 1, 2012 through December 31, 2012	—	—	—	8,992,700
Total	943	$51.55	—	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, 2007, in the Company and each of the indices. Total shareholder return includes reinvested dividends.

As of December 31,	2007	2008	2009	2010	2011	2012
S&P 500	$100	$63	$80	$92	$94	$109
Energen	$100	$46	$75	$78	$81	$74
S15OILP	$100	$63	$91	$103	$95	$97
S15GASUX	$100	$76	$96	$112	$135	$134

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)	2012	2011	2010	2009	2008
INCOME STATEMENT					
Operating revenues	$1,617,169	$1,483,479	$1,578,534	$1,440,420	$1,568,910
Net income	$253,562	$259,624	$290,807	$256,325	$321,915
Diluted earnings per average common share	$3.51	$3.59	$4.04	$3.57	$4.47
BALANCE SHEET					
Total property, plant and equipment, net	$5,541,636	$4,620,776	$3,719,227	$3,144,469	$2,867,648
Total assets	$6,175,890	$5,237,416	$4,363,560	$3,803,118	$3,775,404
Long-term debt	$1,103,528	$1,153,700	$405,254	$410,786	$561,631
Total shareholders' equity	$2,676,690	$2,432,163	$2,154,043	$1,988,243	$1,913,920
COMMON STOCK DATA					
Cash dividends paid per common share	$0.56	$0.54	$0.52	$0.50	$0.48
Diluted average common shares outstanding (000)	72,316	72,332	72,051	71,885	72,030
Price range:					
High	$58.24	$65.44	$49.94	$48.89	$79.57
Low	$40.13	$37.22	$40.25	$23.18	$23.00
Close	$45.09	$50.00	$48.26	$46.80	$29.33

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SELECTED BUSINESS SEGMENT DATA
Energen Corporation

Years ended December 31, (dollars in thousands)	2012	2011	2010	2009	2008
OIL AND GAS OPERATIONS					
Operating revenues					
Natural gas	$288,979	$386,894	$483,935	$460,370	$536,283
Oil	790,345	467,320	404,625	284,750	292,908
Natural gas liquids	85,938	87,466	65,161	67,254	68,216
Other	318	6,846	5,041	10,172	16,725
Total	$1,165,580	$948,526	$958,762	$822,546	$914,132
Non-cash mark-to-market gains (losses) (included in operating revenues above)					
Natural gas	$(515)	$—	$—	$—	$348
Oil	58,786	(37,473)	(3)	(107)	—
Natural gas liquids	479	(114)	—	—	—
Total	$58,750	$(37,587)	$(3)	$(107)	$348
Production volumes					
Natural gas (MMcf)	76,362	71,718	70,924	72,337	67,573
Oil (MBbl)	8,766	6,318	5,131	4,690	4,114
Natural gas liquids (MMgal)	108.1	91.4	79.0	75.2	70.7
Total production volumes (MBOE)	24,066	20,448	18,832	18,537	17,059
Proved reserves					
Natural gas (MMcf)	809,128	957,368	954,387	897,546	1,038,453
Oil (MBbl)	155,348	129,578	103,262	77,963	62,034
Natural gas liquids (MBbl)	56,155	53,957	40,601	30,257	28,953
Total (MMcfe)	2,078,154	2,058,594	1,817,565	1,546,866	1,584,375
Total (MBOE)	346,359	343,099	302,928	257,811	264,063
Other data					
Lease operating expense					
Lease operating expense and other	$250,497	$202,094	$182,180	$181,777	$174,127
Production taxes	55,878	54,951	42,721	35,652	62,552
Total	$306,375	$257,045	$224,901	$217,429	$236,679
Depreciation, depletion and amortization	$377,328	$244,081	$203,823	$184,089	$139,539
Asset impairment	$21,545	$—	$—	$—	$—
Capital expenditures	$1,291,211	$1,115,452	$717,782	$427,399	$449,571
Exploration expense	$19,363	$13,110	$64,584	$10,234	$9,296
Operating income	$367,243	$363,131	$406,729	$353,645	$482,588
NATURAL GAS DISTRIBUTION					
Operating revenues					
Residential	$277,698	$343,740	$414,870	$398,289	$410,106
Commercial and industrial	115,711	136,469	159,658	161,543	178,395
Transportation	58,857	55,234	57,049	53,856	51,723
Other	(677)	(490)	(11,805)	4,186	14,554
Total	$451,589	$534,953	$619,772	$617,874	$654,778
Gas delivery volumes (MMcf)					
Residential	16,014	21,132	24,463	20,921	21,632
Commercial and industrial	8,372	9,994	10,985	9,934	10,934

Transportation	48,106	44,614	46,479	40,903	46,789
Total	72,492	75,740	81,927	71,758	79,355
Average number of customers					
Residential	393,467	395,766	404,697	409,214	413,151
Commercial, industrial and transportation	31,450	31,840	32,632	33,264	33,911
Total	424,917	427,606	437,329	442,478	447,062

Other data					
Depreciation and amortization	$42,270	$39,916	$44,042	$50,995	$48,874
Capital expenditures	$71,869	$73,984	$93,566	$77,809	$63,320
Operating income	$93,216	$86,216	$88,383	$83,984	$81,956

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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, 2012 totaled $253.6 million, or $3.51 per diluted share compared to the year ended December 31, 2011 net income of $259.6 million, or $3.59 per diluted share. This 2.2 percent decrease in earnings per diluted share (EPS) largely reflected lower prices for natural gas and natural gas liquids, increased depreciation, depletion and amortization (DD&A) expense, a noncash impairment on certain natural gas properties in East Texas of approximately $13.4 million after-tax, higher lease operating expense excluding production taxes, increased interest expense, higher exploration expense and an after-tax gain of $3.6 million on the sale of certain oil properties in the Permian Basin during 2011. Positively affecting net income was the impact of a net 3.6 million barrels of oil equivalent (MMBOE) increase in production volumes from Energen Resources Corporation, Energen's oil and gas subsidiary, 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. For the year ended December 31, 2012, Energen Resources earned $204.1 million, as compared with $213 million in the previous year. Alabama Gas Corporation (Alagasco), Energen's utility subsidiary, generated net income of $49.4 million in the current year as compared with net income in the prior period of $46.6 million. For the year ended December 31, 2010, Energen reported net income of $290.8 million, or $4.04 per diluted share.

During 2011, the Company expanded its risk management program for commodity price exposure to include hedges for production in future years not yet currently flowing. These hedges, while not qualifying as cash flow hedges, are considered valid economic hedges and are accounted for as mark-to-market transactions. The mark-to-market hedges are expected to provide further risk mitigation of future cash flows from operations and to provide support for the Company's planned capital expenditures. Derivatives that do not qualify for hedge treatment or are not designated as cash flow hedges are recorded at fair value with gains and losses recognized in operating revenues. Revenues per unit of production, as discussed under Oil and Gas Operations, include realized prices and the effects of designated cash flow hedges and exclude the impact of the mark-to-market hedges.

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. Lower natural gas and natural gas liquids commodity prices of approximately $90 million after-tax, increased DD&A expense of approximately $86 million after-tax, a noncash impairment on certain natural gas properties in East Texas of approximately $13.4 million after-tax, higher lease operating expense of approximately $31 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 on the $3.6 million sale of certain oil properties were partially offset by increased production volumes of approximately $152 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 $21 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.

2011 vs 2010: Energen Resources' net income totaled $213 million in 2011 as compared with $245.3 million in 2010 primarily due to decreased natural gas commodity prices of approximately $64 million after-tax, an after-tax $23.4

million non-cash mark-to-market loss on derivatives, higher DD&A expense of approximately $25 million after-tax, higher lease operating expense of approximately $12 million after-tax, increased production taxes of approximately $8 million and higher administrative expense of approximately $7 million after-tax. These decreases were partially offset by the impact of greater production volumes of approximately $68 million after-tax, lower exploration expense of approximately $32 million after-tax, higher oil and natural gas liquids commodity prices of approximately $12 million after-tax and the after-tax gain of $3.6 million on the sale of certain oil properties in the Permian Basin.

Alagasco earned net income of $46.6 million in 2011 as compared with net income of $46.9 million in 2010 which primarily reflects the timing of rate recovery under Alagasco's rate-setting mechanisms largely offset by 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 2012, 2011 and 2010 totaled $459.4 million, $448.3 million and $493.4 million, respectively. 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. The decrease in operating income for 2011 is primarily due to significantly lower natural gas commodity prices partially offset by increased production at Energen Resources and higher oil and natural gas liquids commodity prices. During 2012 and 2011, 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 oil and gas operations increased in the current year largely as a result of significantly 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. Revenue per unit of production for natural gas production fell 29.7 percent to $3.79 per thousand cubic feet (Mcf), oil revenue per unit of production increased 4.4 percent to $83.45 per barrel and natural gas liquids revenue per unit of production fell 17.7 percent to $0.79 per gallon during 2012. Production rose 17.7 percent to 24.1 MMBOE during 2012. Natural gas production increased 6.5 percent to 76.4 billion cubic feet (Bcf) while oil volumes rose 38.7 percent to 8,766 thousand barrels (MBbl). Production of natural gas liquids increased 18.3 percent to 108.1 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 mark-to-market hedges.

In 2011, revenues from oil and gas operations decreased largely as a result of significantly lower natural gas commodity prices partially offset by the impact of increased natural gas, oil and natural gas liquids production volumes and higher oil and natural gas liquids commodity prices. Production increased due to increased volumes related to the September 2010 and December 2010 purchases of certain Permian Basin properties and field development partially offset by normal production declines. During 2011, revenue per unit of production for natural gas production fell 21 percent to $5.39 per Mcf, oil revenue per unit of production rose 1.3 percent to $79.90 per barrel and natural gas liquids revenue per unit of production increased 15.7 percent to $0.96 per gallon. Production rose 8.6 percent to 20.4 MMBOE during 2011. Natural gas production increased 1.1 percent to 71.7 Bcf while oil volumes rose 23.1 percent to 6,318 MBbl. Production of natural gas liquids increased 15.7 percent to 91.4 MMgal.

Operating fees from coalbed methane operations are calculated as a percentage of net proceeds on certain properties, as defined by the related operating agreements, and vary with changes in natural gas prices, production volumes and operating expenses.

Years ended December 31, (in thousands, except sales price data)	2012	2011	2010
Operating revenues			
Natural gas	$288,979	$386,894	$483,935
Oil	790,345	467,320	404,625
Natural gas liquids	85,938	87,466	65,161
Operating fees	1,921	3,228	3,650
Other	(1,603)	3,618	1,391
Total operating revenues	$1,165,580	$948,526	$958,762
Non-cash mark-to-market gains (losses) (included in operating revenues above)			
Natural gas	$(515)	$—	$—
Oil	58,786	(37,473)	(3)
Natural gas liquids	479	(114)	—
Total	$58,750	$(37,587)	$(3)
Production volumes			
Natural gas (MMcf)	76,362	71,718	70,924
Oil (MBbl)	8,766	6,318	5,131
Natural gas liquids (MMgal)	108.1	91.4	79.0
Total production volumes (MBOE)	24,066	20,448	18,832
Permian Basin - Spraberry Trend production volumes (included in production volumes above)*			
Natural gas (MMcf)	3,592	1,650	554
Oil (MBbl)	2,134	1,136	447
Natural gas liquids (MMgal)	25.8	14.7	6.3
Total production volumes (MBOE)	3,347	1,762	689
Revenue per unit of production including effects of designated cash flow hedges			
Natural gas (per Mcf)	$3.79	$5.39	$6.82
Oil (per barrel)	$83.45	$79.90	$78.86
Natural gas liquids (per gallon)	$0.79	$0.96	$0.83
Revenue per unit of production excluding effects of all derivative instruments			
Natural gas (per Mcf)	$2.71	$3.93	$4.22
Oil (per barrel)	$87.56	$90.53	$75.06
Natural gas liquids (per gallon)	$0.75	$1.11	$0.86
Average production (lifting) cost (per BOE)	$9.45	$9.08	$8.90
Average production tax (per BOE)	$2.32	$2.69	$2.27
Average DD&A rate (per BOE)	$15.50	$11.75	$10.63

* The Spraberry Trend in the Permian Basin contained 15 percent or more of the Company's total proved reserves as of December 31, 2012

Operations and maintenance (O&M) expense rose $56.5 million in 2012 and decreased $19.6 million in 2011. 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. In 2012, lease operating expense (excluding production taxes) increased $48.4 million largely due to increased water disposal costs (approximately $14.5 million), higher workover and repair expense (approximately $8.4 million), higher ad valorem taxes (approximately $6.4 million), Permian Basin liquids-rich oil 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 $2.5 million), additional electrical costs (approximately $2 million), increased labor costs (approximately $1.6 million), higher environmental compliance expense (approximately $1.1 million) and increased nonoperated costs (approximately $1.1 million) partially offset by decreased other O&M expense (approximately $4 million). During 2011, lease operating expense (excluding

production taxes) increased $19.9 million largely due to additional workover and repair expense (approximately $6.5 million), increased marketing and transportation costs (approximately $2.5 million), the Permian Basin property acquisitions (approximately $2.4 million), higher labor costs (approximately $1.8 million), additional water disposal costs (approximately $1.8 million), higher ad valorem taxes (approximately $1.4 million) and increased chemical usage (approximately $1.2 million). On a per unit basis, the average lease operating expense (excluding production taxes) for 2012 was $10.41 per barrel of oil equivalent (BOE) as compared to $9.88 per BOE in the same period a year ago. Administrative expense rose $1.8 million in 2012 largely due to increased labor costs (approximately $4 million) partially offset by decreased costs from the Company's benefit and performance based compensation plans (approximately $2.5 million). In 2011, administrative expense rose $12 million primarily due to higher labor costs (approximately $4 million), increased costs related to the Company’s performance-based compensation plans (approximately $3.9 million) and increased legal expenses (approximately $3 million). Exploration expense rose $6.3 million during 2012 primarily due to charges incurred of $5.3 million for unproved capitalized leasehold costs. Exploration expense fell $51.5 million during 2011 largely due to charges incurred during 2010 of $39.7 million for unproved capitalized leasehold costs and $15.5 million for well costs, all related to Alabama shale leasehold.

DD&A expense increased $154.8 million in 2012, which includes an impairment writedown on certain properties in East Texas of $21.5 million pre-tax to adjust the carrying amount of certain properties to their fair value based on expected future discounted cash flows, and $40.3 million in 2011. The average DD&A rates were $15.50 per BOE in 2012 (excluding the asset impairment), $11.75 per BOE in 2011 and $10.63 per BOE in 2010. The increase in the 2012 and 2011 per unit DD&A rates, which contributed approximately $64.1 million and $22.9 million, respectively, to the increase in DD&A expense, was primarily due to higher rates resulting from the acquisition of properties and an increase in development costs. Increased production volumes also contributed approximately $90.1 million and $17.2 million to the increase in DD&A expense in 2012 and 2011, respectively.

Energen Resources' expense for taxes other than income taxes primarily reflected production-related taxes. Energen Resources recorded severance taxes of $55.9 million, $55 million and $42.7 million for 2012, 2011 and 2010, respectively. Severance taxes were $0.9 million higher in 2012 resulting from higher production volumes largely offset by lower commodity market prices. Increased production volumes contributed approximately $9.7 million to the increase in severance taxes while decreased commodity market prices lowered severance taxes by approximately $8.8 million. In 2011, severance taxes were $12.2 million higher resulting from increased oil and natural gas liquids commodity market prices and higher production volumes. Higher commodity market prices and the impact of increased production volumes contributed approximately $8.6 million and $3.7 million to the increase in severance taxes, respectively. 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 is allowed to earn a range of return of 13.15 percent to 13.65 percent on average equity throughout the term of the Rate Stabilization and Equalization (RSE) order. RSE limits the utility’s equity upon which a return is permitted to 55 percent of total capitalization, subject to certain adjustments. Given existing economic conditions, Alagasco expects only modest growth in equity as annual dividends are typically paid by the utility.

Under the inflation-based Cost Control Management (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 Consumer Price Index For All Urban Consumers (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 the Company 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 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 rider (GSA). 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 $451.6 million, $535.0 million and $619.8 million in 2012, 2011 and 2010, respectively. Sales revenue in 2012 fell primarily due to decreased customer usage of approximately $53 million and a decline in gas cost of approximately $38 million. In 2012, Alagasco had 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. During the year ended December 31, 2011, Alagasco had 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. In 2012, weather that was 27.1 percent warmer than in the prior year contributed to a 24.2 percent decrease in residential sales volumes and a 16.2 percent decline in commercial and industrial volumes. Transportation volumes rose 7.8 percent. In 2011, sales revenue declined largely due to a decrease in gas costs of approximately $44 million and a decline in customer usage of approximately $39 million. Adjustments from the utility's rate setting mechanisms also partially offset the decrease in revenues as Alagasco had net reduction in revenues of $6.7 million pre-tax in 2011, as discussed above. During the year ended December 31, 2010, Alagasco had a net reduction in revenues of $17.4 million pre-tax to bring the return on average equity to midpoint within the allowed range of return. Weather was 15.4 percent warmer in 2011 than in the prior year. Residential sales volumes declined 13.6 percent while commercial and industrial volumes decreased 9 percent. Transportation volumes fell 4 percent. 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. In 2011, lower gas costs along with decreased gas purchase volumes contributed to a 26.3 percent decrease in cost of gas.

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. O&M expense at the utility rose 7.9 percent in 2011 largely due to increased labor-related costs (approximately $3 million), higher marketing expenses (approximately $2.7 million), increased distribution operation expenses (approximately $1.3 million), increased bad debt expense (approximately $0.9 million) and additional consulting and technology costs (approximately $0.8 million). Alagasco's O&M expense fell within the Index Range for the rate years ended September 30, 2012, 2011 and 2010.

Depreciation expense increased 5.9 percent in 2012 largely due to the extension and replacement of the utility's distribution system and replacement of its support systems. In 2011, depreciation expense decreased 9.4 percent primarily due to revised depreciation rates effective June 1, 2010, partially offset due to the extension and replacement of the utility's distribution system and replacement of its support systems. The revised depreciation rates decreased depreciation expense by approximately $6.8 million for the year ended December 31, 2011 from expense amounts calculated using the prior depreciation rate. 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. 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 3.2 percent, 3.1 percent and 3.6 percent in the years ended December 31, 2012, 2011 and 2010, 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)	2012	2011	2010
Natural gas transportation and sales revenues	$451,589	$534,953	$619,772
Cost of natural gas	(142,228)	(233,523)	(316,988)
Operations and maintenance	(141,334)	(139,030)	(128,830)
Depreciation	(42,270)	(39,916)	(44,042)
Income taxes	(30,244)	(26,670)	(29,875)
Taxes, other than income taxes	(32,541)	(36,268)	(41,529)
Operating income	$62,972	$59,546	$58,508
Natural gas sales volumes (MMcf)			

Residential	16,014	21,132	24,463
Commercial and industrial	8,372	9,994	10,985
Total natural gas sales volumes	24,386	31,126	35,448
Natural gas transportation volumes (MMcf)	48,106	44,614	46,479
Total deliveries (MMcf)	72,492	75,740	81,927

Non-Operating Items
Consolidated: Interest expense rose $20.7 million and $5.6 million in 2012 and 2011, respectively, largely 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 includes $100 million with a floating rate of LIBOR plus 1.375 percent, currently 1.59 percent at December 31, 2012 and $200 million swapped to a fixed rate at 2.4175 percent. These increases in interest expense for 2011 were partially offset by the repayment of $150 million of medium-term notes with an interest rate of 7.625 percent in December 2010. Higher short-term borrowings also contributed to the increase in interest expense for both years. The average daily outstanding balance under credit facilities was $331.1 million in 2012. The average daily outstanding balance under credit facilities was $229.1 million in 2011 as compared to $19.7 million in 2010. Income tax expense decreased in 2012 and 2011 largely due to lower pre-tax income.

FINANCIAL POSITION AND LIQUIDITY
The Company's net cash from operating activities totaled $735.7 million, $761.8 million and $671.0 million in 2012, 2011 and 2010, respectively. 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. 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. 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. Net income increased during 2010 largely due to higher realized commodity prices along with an increase in production volumes at Energen Resources. During 2010, the income tax receivable increased approximately $39.9 million associated with the impact of bonus depreciation and the write-off of Alabama shale leasehold. Working capital needs during 2012, 2011 and 2010 at Alagasco were largely affected by lower gas costs compared to the prior period, 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, combined to create the remaining increases in all years.

The Company made net investments of $1,322.2 million during 2012. 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 (including the effects of closing adjustments). This purchase had an effective date of December 1, 2011. Energen acquired total proved reserves of approximately 8.2 MMBOE. 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) and primarily represented expansion and replacement of its distribution system and replacement of its support facilities and information systems. 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 2010, the Company made net investments of $842.7 million. Energen Resources invested $410.3 million in property acquisitions including approximately $201.9 million of unproved leaseholds, $301.2 million for development costs (excludes approximately $26.6 million of accrued development cost) including approximately $258.2 million to drill 251 net development and service wells and $36.5 million for exploration. In September 2010, Energen Resources completed a purchase of oil properties located in the Permian Basin for a cash price of approximately $188 million adding approximately 18 MMBOE in proved reserves. Energen Resources completed, in December 2010, a purchase of oil properties located in the Permian Basin for a cash price of approximately $74 million. The acquisition added approximately 7.6 MMBOE in proved reserves. Energen Resources also completed in December 2010, the purchase of oil properties with only unproved reserves in the Permian Basin for a cash price of $103 million. Energen Resources had cash proceeds in 2010 of $3.2 million primarily from the sale of certain Permian and Black Warrior basin properties. Utility expenditures in 2010 totaled $92.1 million (excludes approximately $0.5 million of accrued capital cost).

During 2012, the Company added approximately 12 MMBOE of reserves primarily from the Permian Basin oil property acquisitions. Also during 2012, Energen Resources added 57 MMBOE of 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. Energen Resources added approximately 66 MMBOE and 53 MMBOE of reserves in 2011 and 2010, respectively.

The Company provided $586.6 million from net financing activities in 2012 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 2010, the Company provided $118.5 million from financing activities primarily from an increase in short-term debt borrowings partially offset by the payment of current maturities for long-term debt of $150.7 million. 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.

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.

Years ended December 31, (in thousands)	2012	2011	2010
Capital and exploration expenditures for:			
Property acquisitions	$138,496	$306,881	$409,042
Development	748,251	621,550	331,850
Exploration	416,678	188,660	36,455
Other	4,543	9,277	4,103
Total	1,307,968	1,126,368	781,450
Less exploration expenditures charged to income	16,757	10,916	63,668
Net capital expenditures	$1,291,211	$1,115,452	$717,782

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

Years ended December 31, (in thousands)	2012	2011	2010
Capital expenditures for:			
Renewals, replacements, system expansion and other	$50,075	$53,970	$68,774
Support systems and facilities	21,794	20,014	24,792
Total	$71,869	$73,984	$93,566

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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 2013, the Company expects its oil and gas capital spending to total approximately $905 million, including $765 million for existing properties and $130 million for exploration. Included in this $765 million is approximately $487 million for the development of previously identified proved undeveloped reserves.

Capital expenditures by area during 2013 are planned as follows:

Year ended December 31, (in thousands)	2013
Permian Basin	$745,000
San Juan Basin	20,000
Exploration	130,000
Other	10,000
Total	$905,000

Energen anticipates having the following drilling rigs and net wells by area during 2013. The drilling rigs presented below are operated while the net wells include operated and non-operated wells.

	Drilling Rigs	Net Wells
Permian Basin	17 – 19	299

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 and from time to time will pursue acquisitions that meet Energen's acquisition criteria. 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.

Impairment

During the first quarter of 2012, Energen Resources recognized a noncash 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. 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 was caused by the impact of lower future natural gas prices. During the first quarter of 2012, future natural gas price curves shifted significantly lower, especially in the next 5 years. This nonrecurring impairment writedown is classified as Level 3 fair value.

During 2010, Energen Resources incurred write-offs of unproved capitalized leasehold costs associated with its Alabama shale acreage. The non-cash charges totaled $39.7 million pre-tax and were charged to exploration expense, which is included in O&M expense, after the Company determined that the shale acreage was not economically viable. Energen Resources also recorded $15.5 million pre-tax in write-offs of well costs related to Alabama shale leasehold.

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 2012 declined approximately 0.6 percent from 2011 and reflected a moderation in decline over the five-year trend. Other factors impacting Alagasco's average customer account include recent warmer weather, 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 and the underlying current and future economic conditions facing the utility's customer base. During the year ended December 31, 2012, Alagasco reduced the bad debt reserve by approximately $6.4 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 $34 million in 2013 but will vary depending upon the price of natural gas. During 2013, Alagasco plans to invest approximately $75 million in capital expenditures for the normal needs of its distribution and support systems and technology-related projects designed to improve customer service. 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.

Stock Repurchases

Energen periodically considers stock repurchases as a capital investment. Energen may buy shares on the open market or in negotiated purchases. The timing and amounts of any repurchases are subject to changes in market conditions. The Company did not repurchase shares of common stock for this program during 2012, 2011 or 2010. The Company expects any future stock repurchases to be funded through internally generated cash flows or through the utilization of credit facilities. During 2012, the Company had noncash purchases of approximately $0.3 million of Company common stock in conjunction with tax withholdings on its non-qualified deferred compensation plan and other stock compensation plans. The Company utilized internally generated cash flows in payment of the related tax withholdings.

Credit Facilities

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 $1,250 million and $100 million, respectively, five-year syndicated unsecured credit facilities (syndicated credit facilities) with domestic and foreign lenders. These syndicated credit facilities replace Energen's $850 million and Alagasco's $150 million three-year syndicated credit facilities. Energen obligations under the $1,250 million 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, 2012.

Working Capital

At December 31, 2012, the Company reported negative working capital of $734.7 million arising from current liabilities of $1,159.8 million exceeding current assets of $425.1 million. The negative working capital is primarily due to a $628 million increase in borrowing under the syndicated unsecured credit facilities and in support of Energen's 2012 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, and working capital of Alagasco is additionally impacted by the recovery and pass-through of regulatory items and the seasonality of Alagasco's business. Energen's accounts receivable and accounts payable at December 31, 2012 include $64.8 million and $2.6 million, respectively, associated with its derivative financial instruments. Working capital at Alagasco reflects an expected pass-through to rate payers of $18.3

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
Energen and Alagasco's current debt ratings by Standard & Poor's are considered investment grade with a stable outlook. Energen and Alagasco's current debt ratings by Moody's Investor Service are considered investment grade (provisional) with a revised outlook as of January 28, 2013 of "ratings under review down from stable.”

Dividends
Energen expects to pay annual cash dividends of $0.58 per share on the Company’s common stock in 2013. 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, 2012:

	Payments Due before December 31,				
(in thousands)	Total	2013	2014-2015	2016-2017	2018 and Thereafter
Short-term debt	$643,000	$643,000	$—	$—	$—
Long-term debt (1)	1,154,028	50,000	280,000	119,000	705,028
Interest payments on debt	485,393	52,557	95,806	79,146	257,884
Purchase obligations (2)	59,287	36,278	14,279	5,699	3,031
Capital lease obligations	3,577	1,730	1,847	—	—
Operating leases	35,653	5,144	9,342	8,121	13,046
Asset retirement obligations (3)	695,932	11,891	5,274	6,248	672,519
Nonqualified supplemental retirement plans	40,500	3,834	3,841	4,924	27,901
Total contractual cash obligations	$3,117,370	$804,434	$410,389	$223,138	$1,679,409

(1) Long-term cash obligations include $0.5 million of unamortized debt discounts as of December 31, 2012.

(2) Certain of the Company's long-term contracts associated with the delivery and storage of natural gas include fixed charges of $59 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 171 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 33.4 million barrels of oil equivalent (MMBOE) through November 2021.

Energen Resources entered into three agreements which commenced at various dates from November 15, 2011 to January 15, 2012 and expire at various dates through January 2015 to secure drilling rigs necessary to execute a portion of its drilling plans. In the unlikely event that Energen Resources discontinues use of these drilling rigs, Energen Resources' total resulting exposure could be as much as $21.9 million depending on the contractor's ability to remarket the drilling rigs.

There are no required contributions to the qualified pension plans during 2013. 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 $9.0 million to the qualified pension plans in January 2013. No additional discretionary contributions are currently expected to be made to the pension plans by the Company during 2013. The Company expects to make discretionary payments of approximately $1.6 million to postretirement benefit program assets during 2013. 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 $12.6 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 2011, 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, 2012.

OUTLOOK

Oil and Gas Operations: Energen Resources plans to continue to implement its growth strategy with capital spending in 2013. Production in 2013 is estimated to be 26.1 MMBOE, including approximately 24.9 MMBOE of estimated production from proved reserves owned at December 31, 2012. 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)	2013
Permian Basin	14.7
San Juan Basin	9.0
Black Warrior Basin	2.0
North Louisiana/East Texas	0.4
Total	26.1

Production volumes by commodity are expected to be as follows:

Year ended December 31, (MMBOE)	2013
Gas	12.1
Oil	10.6
Natural gas liquids	3.4
Total	26.1

During 2013, Energen Resources expects an annualized decline rate of approximately 12.5 percent for its proved developed producing properties owned at December 31, 2012. During the same period, total production from proved properties is expected to increase approximately 3.4 percent and total production is expected to increase approximately 8.8 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, 2012 of approximately 11.1 percent for the 10 year period 2012 to 2022.

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 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 price exposure to its estimated 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, 2012, 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 twelve of its active counterparties and in a net loss position with the remaining two at December 31, 2012. 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 new 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 in compliance with Alagasco's APSC-approved tariff and are recognized as a regulatory asset or regulatory liability.

Energen Resources entered into the following transactions for 2013 and subsequent years:

Production Period	Total Hedged Volumes		Average Contract Price	Description
Natural Gas				
2013	12.7	Bcf	$4.82 Mcf	NYMEX Swaps
	32.8	Bcf	$4.56 Mcf	Basin Specific Swaps - San Juan
	4.6	Bcf	$3.45 Mcf	Basin Specific Swaps - Permian
2014	10.6	Bcf	$4.55 Mcf	NYMEX Swaps
	25.7	Bcf	$4.72 Mcf	Basin Specific Swaps - San Juan
	9.7	Bcf	$3.81 Mcf	Basin Specific Swaps - Permian
Oil				
2013	8,858	MBbl	$90.95 Bbl	NYMEX Swaps
2014	9,796	MBbl	$92.64 Bbl	NYMEX Swaps
2015	*720	MBbl	$90.10 Bbl	NYMEX Swaps
Oil Basis Differential				
2013	3,592	MBbl	$(3.03) Bbl	WTS/WTI Basis Swaps**
	2,760	MBbl	$(1.01) Bbl	WTI/WTI Basis Swaps***
	*925	MBbl	$(1.00) Bbl	WTI/WTI Basis Swaps***
Natural Gas Liquids				
2013	44.5	MMGal	$1.02 Gal	Liquids Swaps

* Contract entered into subsequent to December 31, 2012
**WTS - West Texas Sour/Midland, WTI - West Texas Intermediate/Cushing
***WTI - West Texas Intermediate/Midland, WTI - West Texas Intermediate/Cushing

Alagasco entered into the following natural gas transactions for 2013:

Production Period	Total Hedged Volumes	Description
2013	1.5 Bcf	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, 2012, Energen Resources was in a net gain position of $95.8 million for derivative contracts and estimates that a 10 percent increase or decrease in the commodities prices would have resulted in an approximate $205 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, 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

	December 31, 2011		
(in thousands)	Level 2*	Level 3*	Total
Current assets	$(14,843)	$36,635	$21,792
Noncurrent assets	(8,382)	39,438	31,056
Current liabilities	(98,468)	(8,822)	(107,290)
Noncurrent liabilities	(32,928)	(1,450)	(34,378)
Net derivative asset (liability)	$(154,621)	$65,801	$(88,820)

* 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, 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. As of December 31, 2011, Alagasco had $56.8 million and $3.1 million of derivative instruments which are classified as Level 2 fair values and are included in the above table as current and noncurrent liabilities, respectively. Alagasco had no derivative instruments classified as Level 3 fair values as of December 31, 2012 and 2011.

Level 3 assets as of December 31, 2012 represent approximately 1.5 percent of total assets and an immaterial amount of total liabilities, respectively. 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 $27.0 million change in the fair value of open Level 3 derivative contracts. The resulting impact upon the results of operations would be an approximate $2.5 million associated with open Level 3 mark-to-market derivative contracts. Cash flow 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. The Company and Alagasco expect their derivatives transactions to qualify for an end-user exception which will exempt 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. If, contrary to current expectations, either the Company or Alagasco is not able to utilize the end-user exception, the Company or Alagasco could be forced to curtail their hedging activities or incur significant expense associated with compliance measures and liquidity requirements. A reduction in the ability to utilize derivatives to hedge risks associated with its business could have a material adverse effect on its business, financial condition, results of operations or cash flows.

Natural Gas Distribution: The extension of RSE in December 2007 provides Alagasco the opportunity to continue earning an allowed return on average equity between 13.15 percent and 13.65 percent through December 31, 2014. Under the terms of that extension, RSE will continue beyond that date, unless, after notice to the Company and a hearing, the APSC votes to modify or discontinue its operation. Alagasco's rate schedules for natural gas distribution charges contain a Gas Supply Adjustment 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. Continued low inflation or the risk of deflation combined with a return to higher gas prices resulting in increased bad debt expense could impact the utility's ability to manage its O&M expense sufficiently for the inflation-based cost control requirements of RSE and may result in an average return on equity lower than the allowed range of return. In addition, 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 Natural Gas and Oil 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. 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, 2012. The independent reservoir engineers have issued reports covering approximately 99 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 2013 depreciation, depletion and amortization expense associated with an assumed downward revision in the reported oil and gas reserve amounts at December 31, 2012:

	Percentage Change in Oil & Gas Reserves From Reported Reserves as of December 31, 2012	
(dollars in thousands)	-5%	-10%
Estimated increase in DD&A expense for the year ended December 31, 2013, net of tax	$13,297	$27,893

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 recognizes all derivatives on the balance sheet and measures all derivatives at fair value. Realized gains and losses from derivatives designated as cash flow hedges are recognized in oil and gas production revenues when the forecasted transaction occurs. Energen Resources also periodically enters into derivative transactions that do not qualify for cash flow hedge accounting but are considered by management to be valid economic hedges. Gains and losses from the change in fair value of derivative instruments that do not qualify for hedge accounting are reported in current period operating revenues, rather than in the period in which the hedge transaction is settled. 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 the 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 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 costs was 4.52 percent for the plans for the year ended December 31, 2012. 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 expense was 7 percent for each of the applicable plans for the year ended December 31, 2012. The estimated weighted average rate of increase in the compensation level for pay related plans was 3.59 percent for the year ended December 31, 2012.

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, 2012:

(in thousands)	Pension Expense	Postretirement Expense
Discount rate change	$1,350	$40
Return on assets	$500	$160
Compensation increase	$745	$—

The weighted average discount rate, return on plan assets and estimated rate of compensation increase used in the 2013 actuarial assumptions are 3.47 percent, 7.00 percent and 3.71 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 15, 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, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 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, 2012, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management’s Report On Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP
Birmingham, Alabama
February 28, 2013

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, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012 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, 2012, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management’s Report On Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP
Birmingham, Alabama
February 28, 2013

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CONSOLIDATED STATEMENTS OF INCOME
Energen Corporation

Years ended December 31, (in thousands, except share data)	2012	2011	2010
Operating Revenues			
Oil and gas operations	$1,165,580	$948,526	$958,762
Natural gas distribution	451,589	534,953	619,772
Total operating revenues	1,617,169	1,483,479	1,578,534
Operating Expenses			
Cost of gas	142,228	233,523	316,988
Operations and maintenance	477,883	419,119	429,165
Depreciation, depletion and amortization	419,598	283,997	247,865
Asset impairment	21,545	—	—
Taxes, other than income taxes	88,989	91,734	84,961
Accretion expense	7,534	6,837	6,178
Total operating expenses	1,157,777	1,035,210	1,085,157
Operating Income	459,392	448,269	493,377
Other Income (Expense)			
Interest expense	(65,556)	(44,822)	(39,222)
Other income	4,448	2,334	4,285
Other expense	(903)	(456)	(643)
Total other expense	(62,011)	(42,944)	(35,580)
Income Before Income Taxes	397,381	405,325	457,797
Income tax expense	143,819	145,701	166,990
Net Income	$253,562	$259,624	$290,807
Diluted Earnings Per Average Common Share	$3.51	$3.59	$4.04
Basic Earnings Per Average Common Share	$3.52	$3.60	$4.05
Diluted Average Common Shares Outstanding	72,316,214	72,332,369	72,050,997
Basic Average Common Shares Outstanding	72,119,021	72,055,661	71,845,463

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)	2012	2011	2010
Net Income	$253,562	$259,624	$290,807
Other comprehensive income (loss):			
Current period change in fair value of commodity derivative instruments, net of tax of $40,720, $41,399 and $19,491, respectively	66,438	67,547	31,801
Reclassification adjustment for commodity derivative instruments, net of tax of ($17,994), ($8,953) and ($76,535), respectively	(29,359)	(14,607)	(124,873)
Pension and postretirement plans:			
Amortization of net obligation at transition, net of taxes of $100, $96 and $98, respectively	186	177	182
Amortization of prior service cost, net of taxes of $119, $104 and $104, respectively	221	194	194
Amortization of net loss, net of taxes of $1,676, $1,270 and $1,152, respectively	3,113	2,359	2,139
Current period change in fair value of pension and postretirement plans, net of taxes of ($9,393), ($5,699), and ($783), respectively	(17,443)	(10,584)	(1,455)
Total pension and postretirement plans	(13,923)	(7,854)	1,060
Current period change in fair value of interest rate swap, net of tax of ($1,228) and ($507), respectively	(2,281)	(941)	—
Reclassification adjustment for interest rate swap, net of tax of $574	1,066	—	—
Comprehensive Income	$275,503	$303,769	$198,795

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

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CONSOLIDATED BALANCE SHEETS
Energen Corporation

(in thousands)	December 31, 2012	December 31, 2011
ASSETS		
Current Assets		
Cash and cash equivalents	$9,704	$9,541
Accounts receivable, net of allowance for doubtful accounts of $6,549 and $12,946 at December 31, 2012 and 2011, respectively	277,900	231,925
Inventories		
Storage gas inventory	32,205	44,047
Materials and supplies	28,291	26,420
Liquified natural gas in storage	3,498	3,545
Regulatory asset	45,515	57,143
Income tax receivable	6,664	7,343
Deferred income taxes	8,520	48,818
Prepayments and other	12,823	15,386
Total current assets	425,120	444,168
Property, Plant and Equipment		
Oil and gas properties, successful efforts method	6,439,127	5,166,368
Less accumulated depreciation, depletion and amortization	1,765,241	1,382,526
Oil and gas properties, net	4,673,886	3,783,842
Utility plant	1,416,590	1,358,266
Less accumulated depreciation	573,947	544,838
Utility plant, net	842,643	813,428
Other property, net	25,107	23,506
Total property, plant and equipment, net	5,541,636	4,620,776
Other Assets		
Regulatory asset	110,566	95,633
Pension and other postretirement assets	1,404	—
Long-term derivative instruments	40,577	31,056
Deferred charges and other	56,587	45,783
Total other assets	209,134	172,472
TOTAL ASSETS	$6,175,890	$5,237,416

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, 2012	December 31, 2011
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Long-term debt due within one year	$50,000	$1,000
Notes payable to banks	643,000	15,000
Accounts payable	257,579	302,048
Accrued taxes	30,076	32,359
Customers' deposits	24,705	23,950
Amounts due customers	19,718	21,065
Accrued wages and benefits	24,984	35,258
Regulatory liability	45,116	58,279
Royalty payable	34,426	22,592
Other	30,178	32,328
Total current liabilities	1,159,782	543,879
Long-term debt	1,103,528	1,153,700
Deferred Credits and Other Liabilities		
Asset retirement obligation	118,023	107,340
Pension and other postretirement liabilities	110,282	62,532
Regulatory liability	80,404	87,234
Deferred income taxes	905,601	806,127
Long-term derivative instruments	11,305	34,663
Other	10,275	9,778
Total deferred credits and other liabilities	1,235,890	1,107,674
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, 75,067,760 shares issued at December 31, 2012 and 75,007,412 shares issued at December 31, 2011	751	750
Premium on capital stock	492,108	482,918
Capital surplus	2,802	2,802
Retained earnings	2,314,055	2,100,885
Accumulated other comprehensive income (loss), net of tax		
Unrealized gain on hedges, net	46,352	9,273
Pension and postretirement plans	(52,507)	(38,584)
Interest rate swap	(2,156)	(941)
Deferred compensation plan	2,774	3,511
Treasury stock, at cost: 2,998,620 shares and 3,036,549 shares at December 31, 2012 and 2011, respectively	(127,489)	(128,451)
Total shareholders' equity	2,676,690	2,432,163
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$6,175,890	$5,237,416

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

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
Energen Corporation

(in thousands, except share data)	Common Stock Number of Shares	Common Stock 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, 2009	74,593,431	$746	$461,661	$2,802	$1,626,753	$ 17,615	$ 3,121	$(124,455)	$1,988,243
Net income					290,807				290,807
Other comprehensive loss						(92,012)			(92,012)
Purchase of treasury shares, net								(2,893)	(2,893)
Shares issued for employee benefit plans	192,945	2	6,449						6,451
Deferred compensation obligation							167	(167)	—
Stock based compensation			(83)						(83)
Tax benefit from employee stock plans			907						907
Cash dividends - $0.52 per share					(37,377)				(37,377)
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
					(38,922)				(38,922)

Cash dividends - $0.54 per share									
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 plans			550						550
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

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

CONSOLIDATED STATEMENTS OF CASH FLOWS
Energen Corporation

Years ended December 31, (in thousands)	2012	2011	2010
Operating Activities			
Net income	$253,562	$259,624	$290,807
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	419,598	283,997	247,865
Asset impairment	21,545	—	—
Accretion expense	7,534	6,837	6,178
Deferred income taxes	124,399	129,041	133,840
Bad debt expense	153	2,525	1,565
Change in derivative fair value	(41,819)	36,210	(819)
Gain on sale of assets	(529)	(5,994)	(2,521)
Other, net	15,681	13,298	(568)
Exploratory expense	16,757	10,916	63,668
Net change in:			
Accounts receivable	(11,923)	(16,359)	(31,939)
Inventories	10,018	(14,710)	4,022
Accounts payable	(16,392)	12,978	18,889
Amounts due customers, including gas supply pass-through	(57,747)	(2,597)	20,751
Income tax receivable	679	37,146	(39,937)
Pension and other postretirement benefit contributions	(5,996)	(5,986)	(42,233)
Other current assets and liabilities	217	14,905	1,454
Net cash provided by operating activities	735,737	761,831	671,022
Investing Activities			
Additions to property, plant and equipment	(1,184,300)	(889,614)	(434,121)
Acquisitions, net of cash acquired	(139,563)	(310,193)	(410,348)
Proceeds from sale of assets	2,562	7,987	3,155
Purchase of short-term investments	—	—	(154,880)
Sale of short-term investments	—	—	154,965
Other, net	(881)	(1,679)	(1,464)
Net cash used in investing activities	(1,322,182)	(1,193,499)	(842,693)
Financing Activities			
Payment of dividends on common stock	(40,392)	(38,922)	(37,377)
Issuance of common stock	1,224	6,415	685
Issuance of long-term debt	—	749,952	—
Reduction of long-term debt	(1,218)	(5,547)	(150,729)
Net change in short-term debt	628,000	(290,000)	305,000
Tax benefit on stock compensation	550	986	907
Other	(1,556)	(4,334)	—
Net cash provided by financing activities	586,608	418,550	118,486
Net change in cash and cash equivalents	163	(13,118)	(53,185)
Cash and cash equivalents at beginning of period	9,541	22,659	75,844
Cash and cash equivalents at end of period	$9,704	$9,541	$22,659

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)	2012	2011	2010
Operating Revenues	$451,589	$534,953	$619,772
Operating Expenses			
Cost of gas	142,228	233,523	316,988
Operations and maintenance	141,334	139,030	128,830
Depreciation and amortization	42,270	39,916	44,042
Income taxes			
Current	18,966	(1,388)	1,014
Deferred	11,278	28,058	28,861
Taxes, other than income taxes	32,541	36,268	41,529
Total operating expenses	388,617	475,407	561,264
Operating Income	62,972	59,546	58,508
Other Income (Expense)			
Allowance for funds used during construction	623	807	808
Other income	2,382	1,309	1,923
Other expense	(291)	(320)	(462)
Total other income	2,714	1,796	2,269
Interest Expense			
Interest on long-term debt	13,744	12,100	11,907
Other interest expense	2,540	2,640	1,987
Total interest expense	16,284	14,740	13,894
Net Income	$49,402	$46,602	$46,883

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

BALANCE SHEETS
Alabama Gas Corporation

(in thousands)	December 31, 2012	December 31, 2011
ASSETS		
Property, Plant and Equipment		
Utility plant	$1,416,590	$1,358,266
Less accumulated depreciation	573,947	544,838
Utility plant, net	842,643	813,428
Other property, net	42	43
Current Assets		
Cash	5,559	7,817
Accounts receivable		
Gas	94,011	96,812
Other	5,117	6,858
Affiliated companies	5,742	2,841
Allowance for doubtful accounts	(5,700)	(12,100)
Inventories		
Storage gas inventory	32,205	44,047
Materials and supplies	5,528	4,183
Liquified natural gas in storage	3,498	3,545
Regulatory asset	45,515	57,143
Income tax receivable	2,762	9,762
Deferred income taxes	18,799	21,986
Prepayments and other	4,451	4,422
Total current assets	217,487	247,316
Other Assets		
Regulatory asset	110,566	95,633
Pension and other postretirement assets	848	—
Deferred charges and other	11,290	10,380
Total other assets	122,704	106,013
TOTAL ASSETS	$1,182,876	$1,166,800

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, 2012	December 31, 2011
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, 2012 and 2011, respectively	20	20
Premium on capital stock	31,682	31,682
Capital surplus	2,802	2,802
Retained earnings	325,999	310,234
Total common shareholder's equity	360,503	344,738
Long-term debt	250,028	250,246
Total capitalization	610,531	594,984
Current Liabilities		
Long-term debt due within one year	—	—
Notes payable to banks	77,000	15,000
Accounts payable	51,741	110,552
Accrued taxes	24,186	26,861
Customers' deposits	24,705	23,950
Amounts due customers	19,718	21,065
Accrued wages and benefits	6,703	12,971
Regulatory liability	45,116	58,279
Other	9,018	9,250
Total current liabilities	258,187	277,928
Deferred Credits and Other Liabilities		
Deferred income taxes	189,381	181,492
Pension and other postretirement liabilities	43,611	21,383
Regulatory liability	80,404	87,234
Long-term derivative instruments	—	3,070
Other	762	709
Total deferred credits and other liabilities	314,158	293,888
Commitments and Contingencies		
TOTAL LIABILITIES AND CAPITALIZATION	$1,182,876	$1,166,800

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	Common Stock Par Value	Premium on Capital Stock	Capital Surplus	Retained Earnings	Total Shareholder's Equity
Balance December 31, 2009	1,972,052	$20	$31,682	$2,802	$283,299	$317,803
Net income					46,883	46,883
Cash dividends					(37,367)	(37,367)
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

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)	2012	2011	2010
Operating Activities			
Net income	$49,402	$46,602	$46,883
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	42,270	39,916	44,042
Deferred income taxes	11,278	28,058	28,861
Bad debt expense	146	2,457	1,561
Other, net	10,667	1,560	(10,958)
Net change in:			
Accounts receivable	(13,528)	4,862	(26,567)
Inventories	10,544	(7,371)	5,854
Accounts payable	(5,906)	(1,499)	2,663
Amounts due customers, including gas supply pass-through	(57,747)	(2,597)	20,751
Income tax receivable	7,000	553	(6,846)
Pension and other postretirement benefit contributions	(2,725)	(2,811)	(26,083)
Other current assets and liabilities	(8,654)	(2,802)	14,273
Net cash provided by operating activities	42,747	106,928	94,434
Investing Activities			
Additions to property, plant and equipment	(69,860)	(73,447)	(92,099)
Other, net	(3,252)	(2,743)	(1,827)
Net cash used in investing activities	(73,112)	(76,190)	(93,926)
Financing Activities			
Payment of dividends on common stock	(33,637)	(29,183)	(37,367)
Proceeds from issuance of long-term debt	—	50,000	—
Reduction of long-term debt	(218)	(5,547)	(729)
Net advances to parent company	—	—	(24,962)
Net change in short-term debt	62,000	(55,000)	70,000
Other	(38)	(101)	—
Net cash provided by (used in) financing activities	28,107	(39,831)	6,942
Net change in cash and cash equivalents	(2,258)	(9,093)	7,450
Cash and cash equivalents at beginning of period	7,817	16,910	9,460
Cash and cash equivalents at end of period	$5,559	$7,817	$16,910

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 a diversified energy holding company engaged primarily in the development, acquisition, 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.

Operating Revenue: 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 material production imbalances at December 31, 2012 and 2011.

Derivative Commodity Instruments: Energen Resources recognizes all derivatives on the balance sheet and measures all derivatives at fair value. If a derivative is designated as a cash flow hedge, the effectiveness of the hedge, or the degree that the gain (loss) for the hedging instrument offsets the loss (gain) on the hedged item, is measured at each reporting period. The effective portion of the gain or loss on the derivative instrument is recognized in other comprehensive income (OCI) as a component of shareholders’ equity and subsequently reclassified to operating revenues when the forecasted transaction affects earnings. The ineffective portion of a derivative's change in fair value is required to be recognized in operating revenues immediately. All derivative transactions are included in operating activities on the consolidated statements of cash flows.

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.

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, 2012, 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.

The Company periodically enters into derivatives that do not qualify for cash flow hedge accounting but are considered by management to represent valid economic hedges and are accounted for as mark-to-market transactions. These economic hedges may include, but are not limited to, hedges on estimated future production not yet flowing, basis hedges without a corresponding

New York Mercantile Exchange (NYMEX) hedge, and hedges on non-operated or other properties for which all of the necessary information to qualify for cash flow hedge accounting is either not readily available or subject to change. Derivatives that do not qualify for hedge treatment or are not designated as cash flow hedges are recorded at fair value 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)	2012	2011	2010
Mark-to-market gain (loss) on derivatives	$58,750	$(37,587)	$(3)

All hedge transactions are pursuant to standing authorizations by the Board of Directors, which do not permit speculative positions. The Company formally documents all relationships between hedging instruments and hedged items at the inception of the cash flow 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 hedge transaction, the nature of the risk being hedged and how the hedging instrument's effectiveness in hedging the exposure to the hedged transaction's variability in cash flows attributable to the hedged risk will be assessed. Both at the inception of the cash flow hedge and on an ongoing basis, the Company assesses whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items. The Company discontinues hedge accounting if a derivative has ceased to be a highly effective hedge.

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 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. In general, 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 $14.2 million, $22.2 million and $2.7 million for the period January through December 2012, January through December 2011 and in December 2010, respectively. Alagasco anticipates refunding approximately $18.3 million of refundable negative salvage costs through lower tariff rates over the next twelve months. An additional estimated $53.5 million of refundable negative salvage costs will be refunded to eligible customers on a declining basis through lower tariff rates over a seven year period beginning January 1, 2013. The total amount refundable to customers is subject to adjustments over the entire nine year period for charges made to the Enhanced Stability Reserve (ESR) and other commission-approved charges. The refunds as of December 2012 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 3.2 percent, 3.1 percent and 3.6 percent in the years ended December 31, 2012, 2011 and 2010, respectively. The revised depreciation rates decreased depreciation expense by approximately $6.8 million and $9.2 million for the years ended December 31, 2011 and 2010, respectively, from expense amounts calculated using the prior depreciation rate.

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, 2012. Alagasco had gas imbalances of $0.5 million at December 31, 2011.

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 as either assets or liabilities on the balance sheet at fair value. 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)	2012	2011	2010
Taxes on revenues	$21,479	$25,268	$30,704

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 over-the-counter 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 New York Mercantile Exchange 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 a limited partnership. 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 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 Equivalents

All highly liquid financial instruments with an original maturity of three months or less at the time of purchase are considered to be cash or cash equivalents.

As of December 31, 2012, the Company and Alagasco revised the presentation of outstanding checks in its financial statements. Previously, the Company and Alagasco reflected outstanding checks as a reduction in cash as of the date the checks cleared the bank as opposed to the date the checks were released for payment. Under the revised presentation, as of December 31, 2011, Energen's cash and accounts payable would have been reduced by $8.0 million and $7.3 million, respectively, while accounts receivable would have increased by $0.7 million. Under the revised presentation, as of December 31, 2011, Alagasco's cash and accounts payable would have been reduced by $6.8 million and $6.1 million, respectively, while accounts receivable would have increased by $0.7 million. The Company and Alagasco considered the impact of this adjustment on the December 31, 2011 balance sheets and statements of cash flows for the year then ended and determined that the amounts were not material. The effect of not revising the presentation of cash balances as of December 31, 2011, but presenting the correct cash balances at December 31, 2012, resulted in a decrease of $8.0 million and $6.8 million to Energen and Alagasco's 2012 operating cash flows, respectively. This adjustment caused no impact to Energen or Alagasco's income statements.

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, 2012 and 2011, 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 for retirement eligible employees. The Company utilizes the long-form method of calculating the available pool of windfall tax benefit. For 2012 and 2011, the Company recognized an excess tax benefit of $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. Substantially all of the Company's employees may become eligible for certain benefits if they reach 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 post retirement 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 operations and maintenance (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. RSE's current extension is for a seven-year period through December 31, 2014. RSE will continue after December 31, 2014, unless, after notice to the Company and a hearing, the APSC votes to modify or discontinue the RSE methodology. 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 throughout the term of the RSE order. 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, 2012, 2011 and 2010, Alagasco had net pre-tax reductions in revenues of $6.3 million, $6.7 million and $17.4 million, respectively, to bring the return on average equity to midpoint within the allowed range of return. Under the provisions of RSE, a $7.8 million annual increase, $13.0 million annual increase and $1.3 million annual decrease in revenues became effective December 1, 2012, 2011, and 2010, respectively.

RSE limits the utility's equity upon which a return is permitted to 55 percent of total capitalization, subject to certain adjustments. Under the inflation-based Cost Control Measurement (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 Consumer Price Index For All Urban Consumers (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 the Company 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. In the rate year ended September 30, 2010, $2.5 million of extraordinary bad debt expense was excluded from the CCM calculation. Alagasco's O&M expense fell within the Index Range for the rate years ended September 30, 2012, 2011 and 2010.

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, 2012 and 2011, the net unamortized acquisition adjustments were $3.8 million and $4.4 million, respectively.

3. LONG-TERM DEBT AND NOTES PAYABLE

Long-term debt consisted of the following:

(in thousands)	December 31, 2012	December 31, 2011
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	$155,000
5% Notes, due October 1, 2013	50,000	50,000
4.625% Notes, due September 1, 2021	400,000	400,000
Senior Term Loans, (floating rate interest LIBOR plus 1.375%; 1.59% at December 31, 2012), due March 31, 2014 to November 29, 2016	300,000	300,000
Alabama Gas Corporation:		
5.20% Notes, due January 15, 2020	40,000	40,000
5.70% Notes, due January 15, 2035	35,028	35,246
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	1,154,028	1,155,246
Less amounts due within one year	50,000	1,000
Less unamortized debt discount	500	546
Total	$1,103,528	$1,153,700

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

Years ending December 31, (in thousands)

2013	2014	2015	2016	2017
$50,000	$100,000	$180,000	$100,000	$19,000

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

Years ending December 31, (in thousands)

2013	2014	2015	2016	2017
—	—	$80,000	—	—

In August 2011, the Company issued $400 million in Senior Notes with an interest rate of 4.625 percent due September 1, 2021. In November 2011, the Company issued $300 million in Senior Term Loans (Senior Term Loans) with a floating interest rate due March 31, 2014 through November 29, 2016. The Company used the long-term debt proceeds to replace short-term obligations, enhance liquidity and to finance the property acquisition program at Energen Resources. In December 2011, Alagasco issued $50 million of long-term debt with an interest rate of 3.86 percent due December 21, 2021 to replace short-term obligations.

In December 2011, the Company entered into interest rate swap agreements for $200 million of the Senior Term Loans. The swap agreements exchange a variable interest rate for a fixed interest rate of 2.4175 percent on $200 million of the principal amount outstanding. The fair value of the Company's interest rate swap was a $3.3 million and a $1.5 million liability at December 31, 2012 and 2011, respectively, and is classified as a Level 2 fair value.

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; however, approximately $4 million of the Company's indebtedness is effectively secured through a sale-leaseback arrangement.

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 $1,250 million and $100 million, respectively, five-year syndicated unsecured credit facilities (syndicated credit facilities) with domestic and foreign lenders. These syndicated credit facilities replace Energen's $850 million and Alagasco's $150 million three-year syndicated credit facilities. 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 $1,250 million 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, 2012.

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

(in thousands)	December 31, 2012	December 31, 2011
Energen outstanding	$566,000	$—
Alagasco outstanding	77,000	15,000
Notes payable to banks	643,000	15,000
Available for borrowings	707,000	1,004,000
Total	$1,350,000	$1,019,000
Energen maximum amount outstanding at any month-end	$643,000	$363,000
Energen average daily amount outstanding	$331,068	$229,094
Energen weighted average interest rates based on:		
Average daily amount outstanding	1.82%	2.04%
Amount outstanding at year-end	1.35%	3.58%
Alagasco maximum amount outstanding at any month-end	$77,000	$70,000
Alagasco average daily amount outstanding	$21,254	$29,268
Alagasco weighted average interest rates based on:		
Average daily amount outstanding	1.44%	1.72%
Amount outstanding at year-end	1.11%	3.58%

Energen's total interest expense was $65.6 million, $44.8 million and $39.2 million for the years ended December 31, 2012, 2011 and 2010, respectively. Energen's total interest expense for the year ended December 31, 2012 included capitalized interest expense of $0.5 million. Total interest expense for Alagasco was $16.3 million, $14.7 million and $13.9 million for the years ended December 31, 2012, 2011 and 2010, respectively.

4. INCOME TAXES

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

Years ended December 31, (in thousands)	2012	2011	2010
Taxes estimated to be payable currently:			
Federal	$16,295	$11,595	$31,920
State	3,125	5,065	1,230
Total current	19,420	16,660	33,150
Taxes deferred:			
Federal	119,053	125,622	121,804
State	5,346	3,419	12,036
Total deferred	124,399	129,041	133,840
Total income tax expense	$143,819	$145,701	$166,990

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

Years ended December 31, (in thousands)	2012	2011	2010
Taxes estimated to be payable currently:			
Federal	$18,227	$(1,280)	$859
State	739	(108)	155
Total current	18,966	(1,388)	1,014
Taxes deferred:			
Federal	9,066	24,938	25,582
State	2,212	3,120	3,279
Total deferred	11,278	28,058	28,861
Total income tax expense	$30,244	$26,670	$29,875

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

(in thousands)	December 31, 2012		December 31, 2011	
	Current	Noncurrent	Current	Noncurrent
Deferred tax assets:				
Unbilled and deferred revenue	$10,137	$—	$9,582	$—
Allowance for doubtful accounts	2,408	—	4,848	—
Insurance accruals	2,021	—	2,562	—
Compensation accruals	13,116	—	11,181	—
Inventories	1,664	—	1,438	—
Other comprehensive income	—	19,158	2,799	12,801
Gas supply adjustment related accruals	969	—	1,196	—
Derivative instruments	—	—	13,167	—
State net operating losses and other carryforwards	—	3,577	987	3,022
Other	3,140	25	2,797	27
Total deferred tax assets	33,455	22,760	50,557	15,850
Valuation allowance	(268)	(2,793)	(270)	(2,752)
Total deferred tax assets	33,187	19,967	50,287	13,098
Deferred tax liabilities:				
Depreciation and basis differences	—	898,625	—	791,073
Pension and other costs	—	20,143	—	25,685
Derivative instruments	4,272	3,162	—	—
Other comprehensive income	18,133	—	—	—
Other	2,262	3,638	1,469	2,467
Total deferred tax liabilities	24,667	925,568	1,469	819,225
Net deferred tax assets (liabilities)	$8,520	$(905,601)	$48,818	$(806,127)

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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, 2012		December 31, 2011	
	Current	Noncurrent	Current	Noncurrent
Deferred tax assets:				
Unbilled and deferred revenue	$10,137	$—	$9,582	$—
Allowance for doubtful accounts	2,155	—	4,575	—
Insurance accruals	1,856	—	2,358	—
Compensation accruals	2,645	—	2,274	—
Inventories	1,664	—	1,438	—
Gas supply adjustment related accruals	969	—	1,196	—
State net operating losses and other carryforwards	—	—	987	—
Other	774	2	924	4
Total deferred tax assets	20,200	2	23,334	4
Deferred tax liabilities:				
Depreciation and basis differences	—	167,329	—	156,121
Pension and other costs	—	22,054	—	25,375
Other	1,401	—	1,348	—
Total deferred tax liabilities	1,401	189,383	1,348	181,496
Net deferred tax assets (liabilities)	$18,799	$(189,381)	$21,986	$(181,492)

The Company files a consolidated federal income tax return with all of its subsidiaries. The Company has a noncurrent deferred tax asset of $0.5 million relating to Energen Resources’ $12.2 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 $3.1 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.

Total income tax expense 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)	2012	2011	2010
Income tax expense at statutory federal income tax rate	$139,083	$141,864	$160,229
Increase (decrease) resulting from:			
State income taxes, net of federal income tax benefit	4,904	5,544	8,398
Qualified Section 199 production activities deduction	(94)	(593)	(1,745)
401(k) stock dividend deduction	(514)	(532)	(565)
Other, net	440	(582)	673
Total income tax expense	$143,819	$145,701	$166,990
Effective income tax rate (%)	36.19	35.95	36.48

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)	2012	2011	2010
Income tax expense at statutory federal income tax rate	$27,876	$25,645	$26,865
Increase (decrease) resulting from:			
State income taxes, net of federal income tax benefit	2,238	2,059	2,157
Reversal of tax reserves from audit settlements, net	—	(1,365)	—
Other, net	130	331	853
Total income tax expense	$30,244	$26,670	$29,875
Effective income tax rate (%)	37.97	36.40	38.92

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

(in thousands)	
Balance as of December 31, 2009	$17,797
Additions based on tax positions related to the current year	1,436
Additions for tax positions of prior years	11,703
Reductions for tax positions of prior years	(3,624)
Lapse of statute of limitations	(1,313)
Settlements	(1,409)
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

The reduction for settlements in 2011 and the increase in the additions for tax positions of prior years in 2010 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 2010, the Company had a gross reduction of $3.6 million and recognized in its effective income tax rate a $2.4 million net benefit associated with the release of an unrecognized income tax benefit liability. The Company reassessed its measurement due to recent developments related to the issue and believed that the full amount of the tax benefit has a greater than 50 percent chance of being fully realized. 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

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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, 2012 that would favorably impact the Company's effective tax rate, if recognized, is $5.1 million. The Company recognizes potential accrued interest and penalties related to unrecognized tax benefits in income tax expense. During the years ended December 31, 2012, 2011, and 2010, the Company recognized approximately $25,000 of income, $1.4 million of income and $0.8 million of expense 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, 2012 and 2011, respectively.

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

(in thousands)		
Balance as of December 31, 2009	$7,621	
Additions based on tax positions related to the current year	9	
Additions for tax positions of prior years	11,645	
Reductions for tax positions of prior years (lapse of statute of limitations)	(90	)
Settlements	(244	)
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	

The reduction for settlements in 2011 and the increase in the additions for tax positions of prior years in 2010 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, 2012 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, 2012, 2011, and 2010, Alagasco recognized approximately $1,000 of income, $1.4 million of income and $1.0 million of expense for interest (net of tax benefit) and penalties, respectively. Alagasco had approximately $4,000 and $5,000 for the payment of interest (net of tax benefit) and penalties accrued at December 31, 2012 and 2011, respectively.

The Company and Alagasco's tax returns for years 2009-2011 remain open to examination by the IRS and major state taxing jurisdictions. The Company and Alagasco have on-going income tax examinations under various U.S. and state tax jurisdictions. Accordingly, it is reasonably possible that significant changes to the reserve for uncertain tax benefits may occur as a result of the completion of various audits and the expiration of statute of limitations. Although the timing and outcome of these 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)	2012	2011	2012	2011
	Pension		Postretirement Benefits	
Accumulated benefit obligation	$269,101	$211,896		
Benefit obligation:				
Balance at beginning of period	$250,619	$233,772	$88,064	$83,748
Service cost	10,527	9,173	1,853	1,769
Interest cost	10,801	10,960	4,248	4,443
Actuarial (gain) loss	65,048	17,024	(5,413)	1,858
Plan amendments	—	(169)	—	—
Termination benefit charge	—	414	—	—
Retiree drug subsidy program	—	—	360	302
Benefits paid	(13,455)	(20,555)	(3,327)	(4,056)
Balance at end of period	$323,540	$250,619	$85,785	$88,064
Plan assets:				
Fair value of plan assets at beginning of period	$195,659	$212,454	$78,121	$80,118
Actual return (loss) on plan assets	24,841	1,485	8,778	(1,653)
Employer contributions	2,379	2,275	3,617	3,712
Benefits paid	(13,455)	(20,555)	(3,327)	(4,056)
Fair value of plan assets at end of period	$209,424	$195,659	$87,189	$78,121
Funded status of plan	$(114,116)	$(54,960)	$1,404	$(9,943)
Noncurrent assets	$—	$—	$1,404	$—
Current liabilities	(3,834)	(2,371)	—	—
Noncurrent liabilities	(110,282)	(52,589)	—	(9,943)
Net asset (liability) recognized	$(114,116)	$(54,960)	$1,404	$(9,943)
Amounts recognized to accumulated other comprehensive income:				
Prior service costs, net of taxes	$528	$749	$—	$—
Net actuarial (gain) loss, net of taxes	52,472	36,976	(715)	451
Transition obligation, net of taxes	—	—	222	408
Total accumulated other comprehensive income (loss)	$53,000	$37,725	$(493)	$859

Alagasco recognized a regulatory asset of $89.5 million and $67.8 million as of December 31, 2012 and 2011, respectively, for the portion of the pension plan obligation to be recovered through rates in future periods. Alagasco also recognized a regulatory liability of $1.2 million as of December 31, 2012 for the portion of the postretirement health care and life insurance benefit obligation to be refunded through rates in future periods. Alagasco recognized a regulatory asset of $8.4 million as of December 31, 2011 for the portion of the postretirement health care and life insurance benefit obligation to be recovered through rates in future periods.

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

	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

	December 31, 2011			
(in thousands)	Level 1	Level 2	Level 3	Total
Insurance contracts	$—	$6,620	$5,332	$11,952
United States equities	4,546	—	—	4,546
Global equities	1,798	—	—	1,798
Fixed income	—	9,454	—	9,454
Total	$6,344	$16,074	$5,332	$27,750

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)	2012	2011
Balance at beginning of period	$5,332	$5,069
Unrealized gains relating to instruments held at the reporting date	268	263
Balance at end of period	$5,600	$5,332

The components of net periodic benefit cost were:

Years ended December 31, (in thousands)	2012	2011	2010
Pension Plans			
Components of net periodic benefit cost:			
Service cost	$10,527	$9,173	$8,574
Interest cost	10,801	10,960	11,365
Expected long-term return on assets	(14,093)	(15,471)	(12,915)
Prior service cost amortization	517	496	496
Actuarial loss amortization	8,603	6,435	5,773
Termination benefit charge	—	414	—
Net periodic expense	$16,355	$12,007	$13,293
Postretirement Benefit Plans			
Components of net periodic benefit cost:			
Service cost	$1,853	$1,769	$2,064
Interest cost	4,248	4,443	4,833
Expected long-term return on assets	(4,438)	(4,418)	(3,986)
Actuarial loss amortization	37	—	—
Transition obligation amortization	1,917	1,917	1,917
Net periodic expense	$3,617	$3,711	$4,828

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

Years ended December 31, (in thousands)	2012	2011	2010
Pension Plans			
Net actuarial loss experienced during the year	$28,748	$14,312	$4,332
Net actuarial loss recognized as expense	(4,908)	(3,755)	(3,290)
Prior service cost recognized as expense	(340)	(298)	(298)
Total recognized in other comprehensive income	23,500	10,259	744
Postretirement Benefit Plans			
Net actuarial (gain) loss experienced during the year	$(1,787)	$2,111	$(2,094)
Transition obligation recognized as expense	(294)	(286)	(280)
Total recognized in other comprehensive income (loss)	$(2,081)	$1,825	$(2,374)

Net retirement expense for Alagasco was $7.8 million, $5.2 million and $6.3 million for the years ended December 31, 2012, 2011 and 2010, respectively. 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 expense for Alagasco was $2.7 million, $2.8 million and $3.6 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Estimated amounts to be amortized from accumulated other comprehensive income into pension cost during 2013 are as follows:

(in thousands)	
Amortization of prior service cost	$313
Amortization of net actuarial loss	$8,591

Estimated amounts to be amortized from accumulated other comprehensive income into benefit cost during 2013 are as follows:

(in thousands)	
Amortization of transition obligation	$264

The Company has a long-term disability plan covering most employees. The Company had expense for the years ended December 31, 2012, 2011 and 2010 of $0.7 million, $0.5 million and $0.4 million, respectively.

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

Years ended December 31,	2012	2011	2010
Pension Plans			
Discount rate	4.52 %	4.89 %	5.49 %
Expected long-term return on plan assets	7.00 %	7.25 %	7.25 %
Rate of compensation increase for pay-related plans	3.59 %	3.75 %	3.95 %
Postretirement Benefit Plans			
Discount rate	4.95 %	5.45 %	5.90 %
Expected long-term return on plan assets	7.00 %	7.25 %	7.25 %
Rate of compensation increase	3.55 %	3.61 %	3.69 %

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

Years ended December 31,	2012	2011
Pension Plans		
Discount rate	3.47 %	4.52 %
Rate of compensation increase for pay-related plans	3.71 %	3.59 %
Postretirement Benefit Plans		
Discount rate	4.15 %	4.95 %
Rate of compensation increase for pay-related plans	3.70 %	3.55 %

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,	2012	2011
Health care cost trend rate assumed for next year	6.75 %	7.00 %
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	$(381)	$456
Effect on net postretirement benefit obligation	$(3,688)	$4,342

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	2012	2011	Target	2012	2011
Asset category:						
Equity securities	41%	41%	39%	60%	60%	60%
Debt securities	38%	38%	40%	40%	40%	40%
Other	21%	21%	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, 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

	December 31, 2011			
(in thousands)	Level 1	Level 2	Level 3	Total
United States equities	$37,009	$8,916	$—	$45,925
Global equities	20,064	4,914	4,352	29,330
Fixed income	—	78,443	—	78,443
Alternative investments	—	26,070	13,047	39,117
Cash and cash equivalents	—	2,844	—	2,844
Total	$57,073	$121,187	$17,399	$195,659

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 asset investments consist of limited partnerships and commingled and mutual funds with varying investment strategies. Alternative assets 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)	2012	2011
Balance at beginning of period	$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
Balance at end of period	$14,500	$17,399

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

	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

	December 31, 2011		
(in thousands)	Level 1	Level 2	Total
United States equities	$33,649	$—	$33,649
Global equities	13,088	—	13,088
Fixed income	—	31,384	31,384
Total	$46,737	$31,384	$78,121

The Company had no Level 3 postretirement benefit plan assets. United States equities consisted 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 2013. 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 $9.0 million to the qualified pension plans in January 2013. No additional discretionary contributions are currently expected to be made to the pension plans by the Company during 2013. The Company expects to make benefit payments of approximately $3.8 million during 2013 to retirees with respect to the nonqualified supplemental retirement plans. The Company expects to make discretionary contributions of $1.6 million to the postretirement health care and life insurance benefit plans during 2013.

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
2013	$20,354	$4,435	$(243)
2014	$20,982	$4,586	$(248)
2015	$21,679	$4,754	$(252)
2016	$23,155	$4,940	$(258)
2017	$28,139	$5,165	$(260)
2018-2022	$166,646	$28,565	$(1,333)

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, 2012, total shares reserved for issuance equaled 1,080,108. Expense associated with Company contributions to the ESP was $7.8 million, $6.8 million and $6.2 million for the years ended December 31, 2012, 2011 and 2010, 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 3,418,881 remaining for issuance as of December 31, 2012.

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, 2011 or 2010. A summary of performance share award activity is presented below:

	Stock Incentive Plan	
	Shares	Weighted Average Price
Nonvested at December 31, 2009	111,143	$43.81
Vested and paid	(111,143)	43.81
Nonvested at December 31, 2010	—	$—

During the years ended December 31, 2012, 2011 and 2010, the Company recorded no expense for performance share awards.

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.

A summary of stock option activity as of December 31, 2012, and transactions during the years ended December 31, 2012, 2011 and 2010 are presented below:

	Stock Incentive Plan	
	Shares	Weighted Average Exercise Price
Outstanding at December 31, 2009	1,107,809	$36.83
Granted	281,110	46.69
Exercised	(111,676)	23.83
Forfeited	(1,200)	13.72
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
Exercisable at December 31, 2010	574,992	$41.16
Exercisable at December 31, 2011	677,753	$43.72
Exercisable at December 31, 2012	987,733	$43.75
Remaining reserved for issuance at December 31, 2012	3,418,881	—

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	1/25/2012	1/26/2011	1/27/2010
Awards granted	371,040	293,978	281,110
Fair market value of stock option at grant	$18.79	$19.65	$16.47
Expected life of award	5.8 years	5.8 years	5.7 years
Risk-free interest rate	1.07%	2.45%	2.76%
Annualized volatility rate	39.6%	37.8%	37.3%
Dividend yield	1.0%	1.0%	1.1%

The Company recorded stock option expense of $7.0 million, $5.6 million and $4.6 million during the years ended December 31, 2012, 2011 and 2010, respectively, with a related deferred tax benefit of $2.6 million, $2.1 million and $1.7 million respectively.

The total intrinsic value of stock options exercised during the year ended December 31, 2012, was $1.1 million. During the year ended December 31, 2012, the Company received cash of $1.5 million from the exercise of stock options and paid $1.8 million in settlement of stock appreciation rights. Total intrinsic value for outstanding options as of December 31, 2012, was $5.7 million and $5.7 million for exercisable options. The fair value of options vested for the year ended December 31, 2012 was $5.1 million. As of December 31, 2012, there was $1.9 million of unrecognized compensation cost related to outstanding nonvested stock options.

The following table summarizes options outstanding as of December 31, 2012:

Stock Incentive Plan

Range of Exercise Prices	Shares	Weighted Average Remaining Contractual Life
$14.86	16,270	.08 years
$21.38	5,560	1.08 years
$46.45	150,710	4.00 years
$55.08	7,260	4.50 years
$60.56	184,565	5.00 years
$29.79	333,232	6.00 years
$43.30	4,750	6.67 years
$46.69	281,110	7.00 years
$54.99	293,978	8.00 years
$54.11	371,040	9.00 years
$14.86-$60.56	1,648,475	6.83 years

The weighted average remaining contractual life of currently exercisable stock options is 5.76 years as of December 31, 2012.

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, 2012, and transactions during the years ended December 31, 2012, 2011 and 2010 is presented below:

	Stock Incentive Plan	
	Shares	Weighted Average Price
Nonvested at December 31, 2009	53,005	$32.66
Vested	(28,855)	30.30
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

The Company recorded expense of $0.1 million, $0.1 million and $0.2 million for the years ended December 31, 2012, 2011 and 2010, respectively, related to restricted stock, with a related deferred income tax benefit of $31,000, $47,000 and $70,000, respectively. As of December 31, 2012, there was $0.5 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 2.96 years.

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2004 Stock Appreciation Rights Plan: The Energen 2004 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.

A summary of stock appreciation rights activity as of December 31, 2012, and transactions during the years ended December 31, 2012, 2011 and 2010 are presented below:

	2004 Stock Appreciation Rights Plan	
	Shares	Weighted Average Exercise Price
Outstanding at December 31, 2009	503,215	$35.46
Granted	171,749	46.69
Exercised/forfeited	(18,624)	37.65
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

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. For purposes of this valuation the following assumptions were used to derive the fair values as of December 31, 2012:

Grant date	1/26/2011	1/27/2010	2/13-16/2009	1/28/2009	2/4/2008	2/1/2007
Awards granted	189,984	171,749	3,292	305,257	67,093	85,906
Fair market value of award	$11.19	$11.93	$17.57	$18.46	$5.80	$9.25
Expected life of award	4.6 years	3.6 years	3.0 years	3.0 years	2.6 years	2.0 years
Risk-free interest rate	0.63%	0.44%	0.37%	0.37%	0.31%	0.26%
Annualized volatility rate	40.4%	40.4%	40.4%	40.4%	40.4%	40.4%
Dividend yield	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%

Income associated with stock appreciation rights of $1.0 million was recorded for the year ended December 31, 2012. Expense associated with stock appreciation rights of $4.3 million and $3.4 million was recorded for the years ended December 31, 2011 and 2010, respectively. During the year ended December 31, 2012, the total intrinsic value of stock appreciation rights exercised was $2.6 million. During the year ended December 31, 2012, the Company paid $1.8 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, 2012, and transactions during the years ended December 31, 2012, 2011 and 2010 are presented below:

	Petrotech Incentive Plan
	Shares
Outstanding at December 31, 2009	32,350
Granted (three-year vesting period)	2,442
Paid	(26,587)
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

None of the awards issued included a market condition. Energen Resources recognized expense of $2.6 million, $0.2 million and $0.2 million during 2012, 2011 and 2010, 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, 2012 there were 701,348 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, 11,120 shares, 12,420 shares and 15,400 shares were awarded during the years ended December 31, 2012, 2011 and 2010, respectively, leaving 151,784 shares reserved for issuance as of December 31, 2012.

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, 2012, 2011 and 2010. As of December 31, 2012, 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, 2012, 2011 and 2010, the Company acquired 5,459 shares, 12,867 shares and 62,794 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 33.4 million barrels of oil equivalent (MMBOE) through November 2021.

Energen Resources entered into three agreements which commenced at various dates from November 15, 2011 to January 15, 2012 and expire at various dates through January 2015 to secure drilling rigs necessary to execute a portion of its drilling plans. In the unlikely event that Energen Resources discontinues use of these drilling rigs, Energen Resources' total resulting exposure could be as much as $21.9 million depending on the contractor's ability to remarket the drilling rigs.

Certain of Alagasco's long-term contracts associated with the delivery and storage of natural gas include fixed charges of approximately $59 million through September 2024. During the years ended December 31, 2012, 2011 and 2010, Alagasco recognized approximately $51 million, $51 million and $52 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 171 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.

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 and is the subject of a recent inquiry discussed below. Also discussed below is the recent completion of a removal action at the Huntsville, Alabama manufactured gas plant site. An investigation of the sites does not indicate the present need for other remediation activities and management expects that, should remediation of any such sites be required in the future, Alagasco's share, if any, of such costs will not materially affect the financial position of Alagasco.

In May 2012, Alagasco received from the United States Environmental Protection Agency (EPA) a Request for information Pursuant to Section 104 of CERCLA relating to the EPA's investigation of a site which it refers to as the 35th Avenue Superfund Site in and around Birmingham, Jefferson County, Alabama. The inquiry requests information about a parcel owned by Alagasco and located in the vicinity of the 35th Avenue site. The parcel is the former site of a manufactured gas distribution facility. Alagasco has responded to the inquiry.

In June 2009, Alagasco received a General Notice Letter from the EPA identifying Alagasco as a responsible party for a former manufactured gas plant (MGP) site located in Huntsville, Alabama, and inviting Alagasco to enter an Administrative Settlement Agreement and Order on Consent to perform a removal action at that site. The Huntsville MGP, along with the Huntsville gas distribution system, was sold by Alagasco to the City of Huntsville in 1949. While Alagasco no longer owns the Huntsville site, the Company and the current site owner entered into a Consent Order, and developed and completed during 2011 an action plan for the site. Alagasco has incurred costs associated with the site of approximately $5 million. As of December 31, 2012, the expected remaining costs are not expected to be material to the Company. Alagasco has recorded a corresponding amount, subject to APSC review guidelines, against the refundable negative salvage costs being refunded to customers.

Legal Matters: 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. 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 Energen and its affiliates conduct business in jurisdictions in which the magnitude and frequency of punitive and other damage awards may bear little or no relation to culpability or actual damages, thus making it difficult to predict litigation results.

Various pending or threatened legal proceedings are in progress currently, and the Company has accrued a provision for estimated liability. This provision was increased by $0.1 million during the year ended December 31, 2012.

On November 2, 2011 Energen Resources spudded the Cadenhead 25-1 Well (the Cadenhead Well) in Ward County, Texas. During the drilling phase, Chesapeake Exploration, LLC, notified Energen Resources that it believed it was the owner of the lease from which the Cadenhead Well was producing. Shortly thereafter, Energen Resources filed a declaratory judgment action in the District Court of Ward County, Texas to resolve the title dispute. Energen Resources has a fifty percent working interest in the Cadenhead Well. The Cadenhead Well produced approximately 63 net MBOE in 2012 and is expected to produce approximately 42 net MBOE in 2013. On January 18, 2013, a judgment was entered which was adverse to Energen Resources' claim of ownership. The Company believes the adverse ruling was incorrect, and plans to vigorously pursue all available avenues of appeal.

New Mexico Audits: During the third quarter of 2011, 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, 2012.

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. Energen's total lease payments included as operating lease expense were $20.9 million, $19.1 million and $18.6 million for the years ended December 31, 2012, 2011 and 2010, respectively. Minimum future rental payments required after 2012 under leases with initial or remaining noncancelable lease terms in excess of one year are as follows:

Years Ending December 31, (in thousands)

2013	2014	2015	2016	2017	2018 and thereafter
$5,144	$4,836	$4,506	$4,141	$3,980	$13,046

Alagasco's total payments related to leases included as operating expense, net of approximately $1.0 million of lease expense paid by Energen each year, were $2.1 million, $2.3 million and $2.1 million for the years ended December 31, 2012, 2011 and 2010, respectively. Minimum future rental payments required after 2012 under leases with initial or remaining noncancelable lease terms in excess of one year are as follows:

Years Ending December 31, (in thousands)

2013	2014	2015	2016	2017	2018 and thereafter
$3,629	$3,858	$3,909	$3,934	$3,980	$13,046

Included in the table above are approximately $17.6 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. Such amounts are subject to intercompany allocations but are not subject to contractual agreements.

Capital Lease Obligations: During the first quarter of 2012, the Company entered into capital leases related to certain equipment. The following is a schedule of future minimum lease payments under capital leases together with the present value of the net minimum lease payments as of December 31, 2012:

(in thousands)	
2013	$1,743
2014	1,743
2015	145
Total minimum lease payments	3,631
Less amount representing interest	54
Total present value of minimum lease payments	$3,577

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 $1,255.8 million and $1,214.9 million and has a carrying value of $1,154.0 million and $1,155.2 million at December 31, 2012 and 2011, respectively. The fair value of Alagasco's fixed-rate long-term debt, including the current portion, approximates $284.7 million and $274.9 million and has a carrying value of $250.0 million and $250.2 million at December 31, 2012 and 2011, 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, 2012, the fixed price purchases under these guarantees had a maximum term outstanding through March 2013 with an aggregate purchase price of $0.3 million and a market value of $0.3 million.

Finance Receivables: Alagasco finances third-party contractor sales of merchandise including gas furnaces and appliances. At December 31, 2012 and 2011, Alagasco’s finance receivable totaled approximately $10.7 million and $10.5 million, respectively. These finance receivables currently have an average balance of approximately $3,000 and with terms of up to 60 months. Financing is available only to qualified customers who meet credit worthiness 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 $0.5 million and $0.4 million as of December 31, 2012 and 2011, 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, 2010	$447
Provision	(26)
Allowance for credit losses as of December 31, 2011	421
Provision	49
Allowance for credit losses as of December 31, 2012	$470

Risk Management: At December 31, 2012, 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 twelve of its active counterparties and in a net loss position with the remaining two at December 31, 2012. The four largest counterparty net gain positions at December 31, 2012, Macquarie Bank Limited, J Aron & Company, BP Corporation North America Inc. and Shell Energy North America (US), L.P., constituted approximately $20.0 million, $16.6 million, $13.6 million and $10.3 million gain, respectively, of Energen Resources' net gain 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, 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

(in thousands)	December 31, 2011		
	Oil and Gas Operations	Natural Gas Distribution	Total
Derivative assets or (liabilities) designated as hedging instruments			
Accounts receivable	$73,636	$—	$73,636
Long-term asset derivative instruments	75,982	—	75,982
Total derivative assets	149,618	—	149,618
Accounts receivable	(48,174)*	—	(48,174)
Long-term asset derivative instruments	(36,341)*	—	(36,341)
Accounts payable	(37,070)	—	(37,070)
Long-term liability derivative instruments	(20,386)	—	(20,386)
Total derivative liabilities	(141,971)	—	(141,971)
Total derivatives designated	7,647	—	7,647
Derivative assets or (liabilities) not designated as hedging instruments			
Accounts receivable	(3,670)*	—	(3,670)
Long-term asset derivative instruments	(8,585)*	—	(8,585)
Total derivative assets	(12,255)	—	(12,255)
Accounts payable	(13,416)	(56,804)	(70,220)
Long-term liability derivative instruments	(10,922)	(3,070)	(13,992)
Total derivative liabilities	(24,338)	(59,874)	(84,212)
Total derivatives not designated	(36,593)	(59,874)	(96,467)
Total derivatives	$(28,946)	$(59,874)	$(88,820)

* 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 $28.4 million and a net $5.7 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, 2012 and 2011, respectively.

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	2012	2011	2010
Net gain recognized in OCI on derivative (effective portion), net of tax of $40.7 million, $41.4 million and $19.5 million	—	$66,438	$67,547	$31,801
Gain reclassified from accumulated OCI into income (effective portion)	Operating revenues	$52,694	$26,326	$200,324
Gain (loss) recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	Operating revenues	$(5,340)	$(2,767)	$1,082

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

Years ended December 31, (in thousands)	Location on Income Statement	2012	2011	2010
Gain (loss) recognized in income on derivative	Operating revenues	$61,841	$(37,587)	$(3)

As of December 31, 2012, $32.7 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. The actual amount that will be reclassified to earnings over the next year could vary materially from this amount due to changes in market conditions. As of December 31, 2012, the Company had 5.6 billion and 9.7 billion cubic feet (Bcf) of natural gas hedges which expire during 2013 and 2014, respectively, that did not meet the definition of a cash flow hedge but are considered by the Company to be economic hedges. The Company had 9.7 million and 5.4 million barrels (MMBbl) of oil and oil basis hedges which expire during 2013 and 2014, respectively, that did not meet the definition of a cash flow hedge but are considered by the Company to be economic hedges. The Company had 1.6 million gallons (MMgal) of natural gas liquid hedges which expire during 2013 that did not meet the definition of a cash flow hedge but are considered by the Company to be economic hedges. During 2011, the Company had a discontinuance of hedge accounting when Energen Resources determined it was probable certain forecasted volumes would not occur, which resulted in $63,000 after-tax gain being recognized into operating revenues during the year ended December 31, 2012.

As of December 31, 2012, Energen Resources entered into the following transactions for 2013 and subsequent years:

Production Period	Total Hedged Volumes		Average Contract Price	Description
Natural Gas				
2013	12.7	Bcf	$4.82 Mcf	NYMEX Swaps
	32.8	Bcf	$4.56 Mcf	Basin Specific Swaps - San Juan
	4.6	Bcf	$3.45 Mcf	Basin Specific Swaps - Permian
2014	10.6	Bcf	$4.55 Mcf	NYMEX Swaps
	25.7	Bcf	$4.72 Mcf	Basin Specific Swaps - San Juan
	9.7	Bcf	$3.81 Mcf	Basin Specific Swaps - Permian
Oil				
2013	8,858	MBbl	$90.95 Bbl	NYMEX Swaps
2014	9,796	MBbl	$92.64 Bbl	NYMEX Swaps
Oil Basis Differential				
2013	3,592	MBbl	$(3.03) Bbl	WTS/WTI Basis Swaps*
	2,760	MBbl	$(1.01) Bbl	WTI/WTI Basis Swaps**
Natural Gas Liquids				
2013	44.5	MMGal	$1.02 Gal	Liquids Swaps

*WTS - West Texas Sour/Midland, WTI - West Texas Intermediate/Cushing
**WTI - West Texas Intermediate/Midland, WTI - West Texas Intermediate/Cushing

Alagasco entered into the following natural gas transactions for 2013:

Production Period	Total Hedged Volumes	Description
2013	1.5 Bcf	NYMEX Swaps

As of December 31, 2012, the maximum term over which Energen Resources and Alagasco has hedged exposures to the variability of cash flows is through December 31, 2014 and March 31, 2013, respectively. Alagasco has not entered into any new 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, 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

	December 31, 2011		
(in thousands)	Level 2*	Level 3*	Total
Current assets	$(14,843)	$36,635	$21,792
Noncurrent assets	(8,382)	39,438	31,056
Current liabilities	(98,468)	(8,822)	(107,290)
Noncurrent liabilities	(32,928)	(1,450)	(34,378)
Net derivative asset (liability)	$(154,621)	$65,801	$(88,820)

* 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, 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. As of December 31, 2011, Alagasco had $56.8 million and $3.1 million of derivative instruments which are classified as Level 2 fair values and are included in the above table as current and noncurrent liabilities, respectively. Alagasco had no derivative instruments classified as Level 3 fair values as of December 31, 2012 and 2011.

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 $27 million change in the fair value of open Level 3 derivative contracts. The resulting impact upon the results of operations would be an approximate $2.5 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)	2012	2011	2010
Balance at beginning of period	$65,801	$42,755	$64,517
Realized gains (losses)	63,720	52,716	111,107
Unrealized gains relating to instruments held at the reporting date*	22,160	23,980	(21,521)
Purchases and settlements during period	(62,662)	(53,650)	(111,348)
Balance at end of period	$89,019	$65,801	$42,755

*Includes $19.9 million in mark-to-market gains and $5.2 million in mark-to-market losses for the years ended December 31, 2012 and 2011, respectively. There were no Level 3 mark-to-market gains or losses for the year ended

December 31, 2010.

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, 2012	Valuation Technique*	Unobservable Input*	Range
Natural Gas Basis - San Juan				
2013	$38,254	Discounted Cash Flow	Forward Basis	($0.15 - $0.16) Mcf
2014	$21,100	Discounted Cash Flow	Forward Basis	($0.13 - $0.17) Mcf
Natural Gas Basis - Permian				
2013	$160	Discounted Cash Flow	Forward Basis	($0.13) Mcf
2014	$(871)	Discounted Cash Flow	Forward Basis	($0.12 - $0.13) Mcf
Oil Basis - WTS/WTI				
2013	$10,338	Discounted Cash Flow	Forward Basis	($5.19) Bbl
Oil Basis - WTI/WTI				
2013	$8,217	Discounted Cash Flow	Forward Basis	($2.92 - $3.62) Bbl
Natural Gas Liquids				
2013	$11,821	Discounted Cash Flow	Forward Price	$0.73 - $0.82 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.

Concentration of Credit Risk: Revenues and related accounts receivable from oil and gas operations primarily are generated from the sale of produced natural gas and oil to natural gas and oil 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 29 percent and 13 percent of Energen Resources’ accounts receivable for commodity sales as of December 31, 2012. Energen Resources’ other purchasers each accounted for less than 9 percent of these accounts receivable as of December 31, 2012. During the year ended December 31, 2012, the two largest oil and gas purchasers accounted for approximately 27 percent and 12 percent of Energen Resources’ total operating revenues.

Natural gas distribution operating revenues and related accounts receivable are generated from state-regulated utility natural gas sales and transportation to approximately 425,000 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)	2012			2011			2010		
	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic EPS	$253,562	72,119	$3.52	$259,624	72,056	$3.60	$290,807	71,845	$4.05
Effect of dilutive securities									
Stock options		196			270			190	
Non-vested restricted stock		1			6			16	
Diluted EPS	$253,562	72,316	$3.51	$259,624	72,332	$3.59	$290,807	72,051	$4.04

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For the years ended December 31, 2012, 2011 and 2010, the Company had 849,583, 293,978 and 479,820 options that were excluded from the computation of diluted EPS, as their effect was non-dilutive. For the years ended December 31, 2012, 2011 and 2011, the Company had no shares of non-restricted stock that were excluded from the computation of diluted EPS.

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 2012, 2011 and 2010, 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 of ARO as of December 31, 2009	$88,298	
Liabilities incurred	4,033	
Liabilities settled	(1,094	)
Accretion expense	6,178	
Balance of ARO as of December 31, 2010	97,415	
Liabilities incurred	4,627	
Liabilities settled	(1,539	)
Accretion expense	6,837	
Balance of ARO as of December 31, 2011	107,340	
Liabilities incurred	3,994	
Liabilities settled	(845	)
Accretion expense	7,534	
Balance of ARO as of December 31, 2012	$118,023	

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 $24.9 million and $20.8 million to purge and cap its gas pipelines upon abandonment as a regulatory liability as of December 31, 2012 and 2011, respectively. Regulatory assets for accumulated asset removal costs of $3.3 million and $1.0 million as of December 31, 2012 and 2011, 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.

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11. SUPPLEMENTAL CASH FLOW INFORMATION

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

Years ended December 31, (in thousands)	2012	2011	2010
Interest paid, net of amount capitalized	$61,379	$33,601	$37,517
Income taxes paid	$17,170	$9,432	$83,894
Noncash investing activities:			
Accrued development, exploration costs and other capital	$120,024	$72,030	$75,167
Capitalized depreciation	$80	$93	$116
Capitalized asset retirement obligations costs	$4,409	$4,927	$4,194
Allowance for funds used during construction	$623	$807	$808
Capital lease obligations	$5,072	$—	$—
Noncash financing activities:			
Issuance of common stock for employee benefit plans	$838	$822	$5,765
Treasury stock acquired in connection with tax withholdings	$277	$713	$2,894

The Company recorded a non-cash adjustment for accretion expense of $7.5 million, $6.8 million and $6.2 million during 2012, 2011 and 2010, respectively.

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

Years ended December 31, (in thousands)	2012	2011	2010
Interest paid, net of amount capitalized	$13,513	$12,385	$11,653
Income taxes paid	$16,796	$5,143	$13,063
Interest on affiliated company debt, net	$295	$376	$274
Noncash investing activities:			
Accrued property, plant and equipment costs	$3,536	$2,229	$2,592
Capitalized depreciation	$80	$93	$116
Capitalized asset retirement obligations costs	$415	$300	$161
Allowance for funds used during construction	$623	$807	$808

12. ACQUISITION AND DISPOSITION OF OIL AND GAS PROPERTIES

During the first quarter of 2012, Energen Resources recognized a noncash 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. 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 was caused by the impact of lower future natural gas prices. During the first quarter of 2012, future natural gas price curves shifted significantly lower, especially in the next 5 years. This nonrecurring impairment writedown is classified as Level 3 fair value.

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.

During 2010, Energen Resources incurred write-offs of unproved capitalized leasehold costs associated with its Alabama shale acreage. The non-cash costs totaled $39.7 million pre-tax and were charged to exploration expense, which is included in O&M expense, after the Company determined that the shale acreage was not economically viable. During the year ended December 31, 2010, Energen Resources also recorded $15.5 million pre-tax in write-offs of well costs related to Alabama shale leasehold.

On December 15, 2010, Energen completed the purchase of certain properties in the Permian Basin for a cash purchase price of $74 million. This purchase had an effective date of December 1, 2010. Energen acquired proved reserves of approximately 7.6 MMBOE. Of the proved reserves acquired, an estimated 92 percent are undeveloped. Approximately 62 percent of the acquisition’s estimated proved reserves are oil, 24 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 December 15, 2010, (including the effects of closing adjustments).

(in thousands)	
Consideration given	
Cash (net)	$73,630
Recognized amounts of identifiable assets acquired and liabilities assumed	
Proved properties	$41,066
Unproved leasehold properties	32,500
Accounts receivable	143
Asset retirement obligation	(79)
Total identifiable net assets	$73,630

The impact to operating revenues and operating income from this acquisition was not material for the year ended December 31, 2010.

On December 9, 2010, Energen completed the asset purchase of certain properties in the Permian Basin from SandRidge Energy, Inc. for a cash purchase price of $103 million (including the effects closing adjustments). This purchase had an effective date of December 9, 2010. Energen acquired no proved reserves related to this acquisition. Energen Resources used its credit facilities and internally generated cash flows to finance the acquisition.

On September 30, 2010, Energen completed the purchase of certain properties in the Permian Basin for a cash price of $188 million. This purchase had an effective date of September 1, 2010. Energen acquired proved reserves of approximately 18 MMBOE. Of the proved reserves acquired, an estimated 89 percent are undeveloped. Approximately 65 percent of the proved reserves are oil, 22 percent are natural gas liquids and natural gas comprises the remaining 13 percent. Energen Resources used its 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 September 30, 2010, (including the effects of closing adjustment).

(in thousands)	
Consideration given	
Cash (net)	$188,314
Recognized amounts of identifiable assets acquired and liabilities assumed	
Proved properties	$151,747
Unproved leasehold properties	35,360
Accounts receivable	1,461
Asset retirement obligation	(142)
Accounts payable	(112)
Total identifiable net assets	$188,314

Included in the Company’s consolidated results of operations for the year ended December 31, 2010, is $5 million of operating revenues and $2.1 million in operating income resulting from the operation of the properties acquired above.

13. REGULATORY ASSETS AND LIABILITIES

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

(in thousands)	December 31, 2012		December 31, 2011	
	Current	Noncurrent	Current	Noncurrent
Regulatory assets:				
Pension and postretirement assets	$170	$90,708	$170	$77,587
Accretion and depreciation for asset retirement obligation	—	16,536	—	13,981
Risk management activities	2,593	—	56,804	3,070
Rate recovery of asset removal costs, net	—	3,322	—	994
Gas supply adjustment	42,726	—	—	—
Other	26	—	169	1
Total regulatory assets	$45,515	$110,566	$57,143	$95,633
Regulatory liabilities:				
RSE adjustment	$1,740	$—	$2,931	$—
Unbilled service margin	25,078	—	22,419	—
Postretirement liabilities	—	1,237	—	—
Gas supply adjustment	—	—	12,626	—
Refundable negative salvage	18,265	53,467	20,269	65,646
Asset retirement obligation	—	24,930	—	20,785
Other	33	770	34	803
Total regulatory liabilities	$45,116	$80,404	$58,279	$87,234

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.

14. 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 $5.7 million and $2.8 million at December 31, 2012 and 2011, respectively. Interest income and expense between affiliates is calculated monthly based on the market weighted average interest rate. Alagasco had $0.3 million, $0.4 million and $0.3 million in affiliated company interest expense during the years ended December 31, 2012, 2011 and 2010, respectively.

15. 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. The Company is currently evaluating the impact of the ASU but does not expect this update to have a material impact on its results of operations. 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 remain unchanged.

In June 2011, the FASB issued ASU No. 2011-05, Presentation of Comprehensive Income. This update requires entities to present the components of net income and other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. The amendments in this update do not change the items that must be reported in other comprehensive income or when an item of other comprehensive income must be reclassified to net income. This amendment was effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. Adoption of this update did not have a material impact on the consolidated financial statements or results of operations.

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 is effective for annual and interim reporting periods beginning after December 15, 2012. The Company is currently evaluating the impact of the ASU but does not expect this update to have a material impact on its consolidated financial statements or results of operations.

In May 2011, the FASB issued ASU No. 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirement in U.S. GAAP and International Financial Reporting Standards (IFRSs). The amendments in this update result in common fair value measurement and disclosure requirements in U.S. GAAP and IFRSs. The amendments are effective during interim and annual periods beginning after December 15, 2011. This standard did not have a material impact on the consolidated condensed financial statements of the Company. The additional fair value disclosures are included in Note 8, Financial Instruments.

16. SUMMARIZED QUARTERLY FINANCIAL DATA (Unaudited)

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

	Year ended December 31, 2012			
(in thousands, except per share amounts)	First	Second	Third	Fourth
Operating revenues	$418,444	$470,355	$295,324	$433,046
Operating income	$104,170	$220,598	$19,458	$115,166
Net income	$57,406	$131,287	$2,046	$62,823
Diluted earnings per average common share	$0.79	$1.82	$0.03	$0.87
Basic earnings per average common share	$0.80	$1.82	$0.03	$0.87

	Year ended December 31, 2011			
(in thousands, except per share amounts)	First	Second	Third	Fourth
Operating revenues	$486,364	$330,399	$378,568	$288,148
Operating income	$159,881	$106,335	$150,412	$31,641
Net income	$94,268	$63,325	$87,599	$14,432
Diluted earnings per average common share	$1.30	$0.87	$1.21	$0.20
Basic earnings per average common share	$1.31	$0.88	$1.22	$0.20

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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, 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

	Year ended December 31, 2011			
(in thousands)	First	Second	Third	Fourth
Operating revenues	$269,572	$86,309	$59,616	$119,456
Operating income (loss)	$75,059	$1,163	$(10,681)	$20,675
Net income (loss)	$44,175	$262	$(9,093)	$11,258

17. OIL AND GAS OPERATIONS (Unaudited)

Capitalized Costs: The following table sets forth capitalized costs:

(in thousands)	December 31, 2012	December 31, 2011
Proved	$6,241,148	$4,927,576
Unproved	197,979	238,792
Total capitalized costs	6,439,127	5,166,368
Accumulated depreciation, depletion and amortization	1,765,241	1,382,526
Capitalized costs, net	$4,673,886	$3,783,842

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)	2012	2011	2010
Property acquisition:			
Proved	$79,862	$214,993	$207,161
Unproved	58,634	91,888	201,881
Exploration	419,284	190,854	37,371
Development	749,256	623,775	332,541
Total costs incurred	$1,307,036	$1,121,510	$778,954

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)	2012	2011	2010
Gross revenues*	$1,167,183	$944,908	$957,371
Production (lifting costs)	306,375	257,045	224,901
Exploration expense	19,363	13,110	64,584
Depreciation, depletion and amortization	394,668	240,232	200,179
Accretion expense	7,534	6,837	6,178
Income tax expense	157,670	154,180	166,750
Results of operations from producing activities	$281,573	$273,504	$294,779

*The years ended December 31, 2012, 2011 and 2010 gross revenues includes a pre-tax non cash mark-to-market gain on derivatives of $58.8 million, a pre-tax non-cash mark-to-market loss on derivatives of $37.6 million and a pre-tax non-cash mark-to-market loss on derivatives of $3,000, 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, 2012, 2011 and 2010. 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, 2012. Ryder Scott audited the reserve estimates for coalbed methane in the Black Warrior and 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 99 percent of the Company's ending proved reserves indicating that in their judgment the estimates are reasonable in the aggregate.

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
Year ended December 31, 2010	Gas MMcf	Oil MBbl	NGL MBbl	Total MMBOE
Proved reserves at beginning of period	897,546	77,963	30,257	257.8
Revisions of previous estimates	66,679	(2,243)	2,434	11.3
Purchases	21,700	16,443	5,730	25.8
Extensions and discoveries	39,570	16,234	4,058	26.8
Production	(70,924)	(5,131)	(1,880)	(18.8)
Sales	(184)	(4)	2	—
Proved reserves at end of period	954,387	103,262	40,601	302.9
Proved developed reserves at end of period	786,292	72,030	28,809	231.9
Proved undeveloped reserves at end of period	168,095	31,232	11,792	71.0

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.

2010 Activities: Energen Resources had upward reserve revisions during 2010 which totaled 11.3 MMBOE. The Black Warrior Basin had upward reserve revisions totaling 0.6 MMBOE of which approximately 1.3 MMBOE related to changes in year-end pricing partially offset by downward reserve revisions of 0.7 MMBOE. The San Juan Basin upward reserve revisions of 11 MMBOE included 7.6 MMBOE related to changes in year-end pricing and 8.2 MMBOE associated with well performance partially offset by 5.3 MMBOE of downward reserve revisions resulting from the SEC’s five-year development rule. Downward reserve revisions of 1.3 MMBOE in the Permian Basin were due to lower than anticipated injection response in certain waterflood units offset by 3.0 MMBOE of estimated positive price related revisions.

Energen Resources purchased 25.8 MMBOE of reserves during 2010 primarily related to the acquisitions of oil properties in the Permian Basin.

During 2010, Energen Resources had extensions and discoveries of 26.8 MMBOE of which 77 percent were proved undeveloped reserves and 23 percent were proved developed reserves. Extension drilling resulted in 26.6 MMBOE of discoveries with exploratory drilling providing 0.3 MMBOE of discoveries. The San Juan Basin added 6.4 MMBOE of reserves through the drilling or identification of 36 well locations; additionally, 1 sidetrack well added 1.1 MMBOE of reserves. The Permian Basin added 22.1 MMBOE of reserves primarily through the drilling or identification of 271 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, 2012, 2011 and 2010, the Company had a deferred hedging gain of $74.8 million, a deferred hedging gain of $15 million and a deferred hedging loss of $70.4 million, respectively, all of which are excluded from the calculation of standardized measure of future net cash flows.

Years ended December 31, (in thousands)	2012	2011	2010
Future gross revenues	$17,735,363	$18,196,229	$13,210,211
Future production costs	5,715,248	5,823,395	4,959,403
Future development costs	1,892,600	1,539,072	1,026,903
Future income tax expense	2,809,411	3,326,382	2,201,742
Future net cash flows	7,318,104	7,507,380	5,022,163
Discount at 10% per annum	3,618,785	3,878,217	2,555,027
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$3,699,319	$3,629,163	$2,467,136
Discounted future net cash flows before income taxes	$4,411,399	$4,691,086	$3,155,746

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

Years ended December 31, (in thousands)	2012	2011	2010
Balance at beginning of year	$3,629,163	$2,467,136	$1,563,190
Revisions to reserves proved in prior years:			
Net changes in prices, production costs and future development costs	(922,792)	707,411	945,179
Net changes due to revisions in quantity estimates	(383,755)	(80,004)	36,349
Development costs incurred, previously estimated	472,603	392,720	195,269
Accretion of discount	362,916	246,714	156,319
Changes in timing and other	(317,244)	(25,937)	15,815
Total revisions	(788,272)	1,240,904	1,348,931
New field discoveries and extensions, net of future production and development costs	1,025,419	755,977	319,223
Sales of oil and gas produced, net of production costs	(812,781)	(763,171)	(576,755)
Purchases	189,755	232,768	278,384
Sales	—	—	87
Net change in income taxes	456,035	(304,451)	(465,924)
Net change in standardized measure of discounted future net cash flows	70,156	1,162,027	903,946
Balance at end of year	$3,699,319	$3,629,163	$2,467,136

18. INDUSTRY SEGMENT INFORMATION

The Company is principally engaged in two business segments: the development, acquisition, 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)	2012	2011	2010
Operating revenues			
Oil and gas operations	$1,165,580	$948,526	$958,762
Natural gas distribution	451,589	534,953	619,772
Total	$1,617,169	$1,483,479	$1,578,534
Operating income (loss)			
Oil and gas operations	$367,243	$363,131	$406,729
Natural gas distribution	93,216	86,216	88,383
Eliminations and corporate expenses	(1,067)	(1,078)	(1,735)
Total	$459,392	$448,269	$493,377
Depreciation, depletion and amortization expense			
Oil and gas operations	$377,328	$244,081	$203,823
Natural gas distribution	42,270	39,916	44,042
Total	$419,598	$283,997	$247,865
Interest expense			
Oil and gas operations	$49,972	$30,907	$25,753
Natural gas distribution	16,284	14,740	13,894
Eliminations and other	(700)	(825)	(425)
Total	$65,556	$44,822	$39,222
Income tax expense (benefit)			
Oil and gas operations	$114,375	$120,079	$138,775
Natural gas distribution	30,244	26,670	29,875
Other	(800)	(1,048)	(1,660)
Total	$143,819	$145,701	$166,990
Capital expenditures			
Oil and gas operations	$1,291,211	$1,115,452	$717,782
Natural gas distribution	71,869	73,984	93,566
Total	$1,363,080	$1,189,436	$811,348
Identifiable assets			
Oil and gas operations	$4,975,170	$4,046,242	$3,160,601
Natural gas distribution	1,177,134	1,163,959	1,166,899
Eliminations and other	23,586	27,215	36,060
Total	$6,175,890	$5,237,416	$4,363,560
Property, plant and equipment, net			
Oil and gas operations	$4,697,683	$3,806,787	$2,936,284
Natural gas distribution	842,685	813,471	782,665
Other	1,268	518	278
Total	$5,541,636	$4,620,776	$3,719,227

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS

Energen Corporation

Years ended December 31, (in thousands)	2012	2011	2010
ALLOWANCE FOR DOUBTFUL ACCOUNTS			
Balance at beginning of year	$12,946	$15,048	$17,251
Additions:			
Charged to income	1,415	4,269	2,665
Recoveries and adjustments	(1,262)	(1,744)	(1,100)
Net additions	153	2,525	1,565
Less uncollectible accounts written off	(6,550)	(4,627)	(3,768)
Balance at end of year	$6,549	$12,946	$15,048

Alabama Gas Corporation

Years ended December 31, (in thousands)	2012	2011	2010
ALLOWANCE FOR DOUBTFUL ACCOUNTS			
Balance at beginning of year	$12,100	$14,200	$16,400
Additions:			
Charged to income	1,409	4,202	2,655
Recoveries and adjustments	(1,263)	(1,745)	(1,094)
Net additions	146	2,457	1,561
Less uncollectible accounts written off	(6,546)	(4,557)	(3,761)
Balance at end of year	$5,700	$12,100	$14,200

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, 2012. Management based this assessment on criteria for effective internal control over financial reporting described in "Internal Control - Integrated Framework" 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, 2012, Energen Corporation maintained effective internal control over financial reporting. The effectiveness of Energen Corporation’s internal control over financial reporting as of December 31, 2012 has been audited by PricewaterhouseCoopers, LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 28, 2013

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, 2012. Management based this assessment on criteria for effective internal control over financial reporting described in "Internal Control - Integrated Framework" 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, 2012, 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, 2012 has been audited by PricewaterhouseCoopers, LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 28, 2013

c. Changes in Internal Control Over Financial Reporting

Our chief executive officer and chief financial officer of Alabama Gas 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.

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 24, 2013. The definitive proxy statement will be filed on or about March 27, 2013.

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 24, 2013.

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 24, 2013.

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 24, 2013.

c. Securities Authorized for Issuance Under Equity Compensation Plans

The information regarding securities authorized for issuance under equity compensation plans is included in Part 2 under Item 4.

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 24, 2013.

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 24, 2013.

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 October 3, 2003, pursuant to Section 301 of the Energen 1996 Indenture setting forth the terms of the 5 percent Notes due October 1, 2013, which was filed as Exhibit 4 to Energen's Current Report on Form 8-K, dated October 3, 2003
*4(a)(v)	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 November 29, 2011, with respect to a $300 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 and BBVA Compass, as Co-Syndication Agents, U.S. Bank National Association, as Documentation Agent, and the lenders party thereto, which was filed as Exhibit 10.1 to Energen's Current Report on Form 8-K filed December 5, 2011
*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)	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(h)	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(i)	Amended Exhibits A and B, effective June 1, 2009, to Firm Transportation Service Agreement (No. FSNG1) between Southern Natural Gas Company and Alabama Gas Corporation which was filed as Exhibit 10(c)(i) to Energen’s Annual Report on Form 10-K for the year ended December 31, 2009

*10(j)	Amended Exhibits A and B, effective September 1, 2010, to Firm Transportation Service Agreement (No. FSNG1) between Southern Natural Gas Company and Alabama Gas Corporation which was filed as Exhibit 10(c)(ii) to Energen’s Annual Report on Form 10-K for the year ended December 31, 2009
*10(k)	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(l)	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(m)	Occluded Gas Lease, dated January 1, 1986 and First through Seventh Amendments, which was filed as Exhibit 10(f) to Energen’s Annual Report on Form 10-K for the year ended December 31, 2005
*10(n)	Eighth Amendment to Occluded Gas Lease, dated January 1, 2009, while was filed as Exhibit 10(f)(i) to Energen’s Annual Report on Form 10-k for the year ended December 31, 2008
*10(o)	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(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 1, 2012) which was filed as Exhibit 10.2 to Energen’s Current Report on Form 8-K filed December 13, 2012
10(r)	Form of Stock Option Agreement under the Energen Corporation Stock Incentive Plan
10(s)	Form of Restricted Stock Agreement under the Energen Corporation Stock Incentive Plan
10(t)	Form of Performance Share Award under the Energen Corporation Stock Incentive Plan
10(u)	Energen Corporation 1997 Deferred Compensation Plan (as amended December 12, 2012)
*10(v)	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(w)	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, 2012 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)

February 28, 2013	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:

February 28, 2013	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
February 28, 2013	By /s/ Charles W. Porter, Jr. Charles W. Porter, Jr. Vice President, Chief Financial Officer and Treasurer of Energen Corporation and Alabama Gas Corporation
February 28, 2013	By /s/ Russell E. Lynch, Jr. Russell E. Lynch, Jr. Vice President and Controller of Energen Corporation
February 28, 2013	By /s/ William D. Marshall William D. Marshall Vice President and Controller of Alabama Gas Corporation
February 28, 2013	* Julian W. Banton Director
February 28, 2013	* Kenneth W. Dewey Director
February 28, 2013	* Judy M. Merritt Director
February 28, 2013	* Stephen A. Snider Director
February 28, 2013	* David W. Wilson Director
	*By /s/ Charles W. Porter, Jr. Charles W. Porter, Jr.,

Attorney-in-Fact

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