UNIT CORP
Form 10-K
February 26, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-K
ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2012
OR
TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission file number: 1-9260
UNIT CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	73-1283193
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
7130 South Lewis, Suite 1000 Tulsa, Oklahoma	74136
(Address of principal executive offices)	(Zip Code)

(Registrant's telephone number, including area code) (918) 493-7700
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $.20 per share	NYSE
Rights to Purchase Series A Participating Cumulative Preferred Stock	NYSE

Securities registered pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes [x] No [ ]
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.
Yes [ ] No [x]
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [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). Yes [x] No [ ]
Indicate by 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. [x]
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	[x]	Accelerated filer	[ ]	Non-accelerated filer	[ ]	Smaller reporting company	[ ]

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

As of June 30, 2012, the aggregate market value of the voting and non-voting common equity (based on the closing price of the stock on the NYSE on June 30, 2012) held by non-affiliates was approximately $1,089,162,162. Determination of stock ownership by non-affiliates was made solely for the purpose of this requirement, and the registrant is not bound by these determinations for any other purpose.

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

Class	Outstanding at February 15, 2013
Common Stock, $0.20 par value per share	49,158,255 shares

DOCUMENTS INCORPORATED BY REFERENCE

Document	Parts Into Which Incorporated
Portions of the registrant's definitive proxy statement (the "Proxy Statement") with respect to its annual meeting of shareholders scheduled to be held on May 1, 2013. The Proxy Statement shall be filed within 120 days after the end of the fiscal year to which this report relates.	Part III

Exhibit Index—See Page 120

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FORM 10-K
UNIT CORPORATION

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DEFINITIONS

The following are explanations of some of the terms used in this report.
ARO – Asset retirement obligations.
ASC – FASB Accounting Standards Codification.
ASU – Accounting Standards Update.
Bcf – Billion cubic feet of natural gas.
Bcfe – Billion cubic feet of natural gas equivalent. Determined using the ratio of one barrel of crude oil or NGLs to six Mcf of natural gas.
Bbl – Barrel, or 42 U.S. gallons liquid volume.
Boe – Barrel of oil equivalent. Determined using the ratio of six Mcf of natural gas to one barrel of crude oil or NGLs.
BOKF – Bank of Oklahoma Financial Corporation.
Btu – British thermal unit, used in terms of gas volumes. Btu is used to refer to the amount of natural gas required to raise the temperature of one pound of water by one degree Fahrenheit at one atmospheric pressure.
Development drilling – The drilling of a well within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.
DD&A – Depreciation, depletion, and amortization.
FASB – Financial and Accounting Standards Board.
Finding and development costs – Costs associated with acquiring and developing proved natural gas and oil reserves which are capitalized under generally accepted accounting principles, including any capitalized general and administrative expenses.
Gross acres or gross wells – The total acres or wells in which a working interest is owned.
IF – Inside FERC (U.S. Federal Energy Regulatory Commission).
LIBOR – London Interbank Offered Rate.
MBbls – Thousand barrels of crude oil or other liquid hydrocarbons.
Mcf – Thousand cubic feet of natural gas.
Mcfe – Thousand cubic feet of natural gas equivalent. Determined using the ratio of one barrel of crude oil or NGLs to six Mcf of natural gas.
MMBbls – Million barrels of crude oil or other liquid hydrocarbons.
MMBoe – Million barrels of oil equivalents.
MMBtu – Million Btu's.
MMcf – Million cubic feet of natural gas.

MMcfe – Million cubic feet of natural gas equivalent. Determined using the ratio of one barrel of crude oil or NGLs to six Mcf of natural gas.
Net acres or net wells – The sum of the fractional working interests owned in gross acres or gross wells.
NGLs – Natural gas liquids.
NGPL-TXOK – Natural Gas Pipeline Co. of America/Texok zone.
NYMEX – The New York Mercantile Exchange.
OPIS – Oil Price Information Service.
PEPL – Panhandle East Pipeline Co.
Play – A term applied by geologists and geophysicists identifying an area with potential oil and gas reserves.
Producing property – A natural gas or oil property with existing production.
Proved developed reserves – Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and through installed extraction equipment and infrastructure operational at the time of the reserves estimate . For additional information, see the SEC's definition in Rule 4-10(a)(3) of Regulation S-X.
Proved reserves – Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs and under existing economic conditions, operating methods, and government

regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. For additional information, see the SEC's definition in Rule 4-10(a)(2)(i) through (iii) of Regulation S-X.

Proved undeveloped reserves – Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. For additional information, see the SEC's definition in Rule 4-10(a)(4) of Regulation S-X.

Reasonable certainty (in regards to reserves) – If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

Reliable technology – A grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

SARs – Stock appreciation rights.

Unconventional play – Plays targeting tight sand, carbonates, coal bed, or oil and gas shale reservoirs. The reservoirs tend to cover large areas and lack the readily apparent traps, seals, and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These reservoirs generally require horizontal wells and fracture stimulation treatments or other special recovery processes in order to produce economically.

Undeveloped acreage – Lease acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of natural gas or oil regardless of whether the acreage contains proved reserves.

Well spacing – The regulation of the number and location of wells over an oil or gas reservoir, as a conservation measure. Well spacing is normally accomplished by order of the appropriate regulatory conservation commission.

Workovers – Operations on a producing well to restore or increase production.

WTI – West Texas Intermediate, the benchmark crude oil in the United States.

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UNIT CORPORATION
Annual Report
For The Year Ended December 31, 2012

PART I

Item 1. Business

Unless otherwise indicated or required by the context, the terms "Company", "Unit", "us", "our", "we", and "its" refer to Unit Corporation and, as appropriate, one or more of Unit Corporation and its subsidiaries.

Our executive offices are at 7130 South Lewis, Suite 1000, Tulsa, Oklahoma 74136; our telephone number is (918) 493-7700.

Information regarding our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to these reports, will be made available in print, free of charge, to any shareholders who request them. They are also available on our internet website at www.unitcorp.com, as soon as reasonably practicable after we electronically file these reports with or furnish them to the Securities and Exchange Commission (SEC). Materials we file with the SEC may be read and copied at the SEC's Public Reference Room at 100 F. Street, N.E. Room 1580, N.W., Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC also maintains an Internet website at www.sec.gov that contains reports, proxy and information statements, and other information regarding our company that we file electronically with the SEC.

In addition, we post on our Internet website, www.unitcorp.com, copies of our corporate governance documents. Our corporate governance guidelines and code of ethics, and the charters of our Board's Audit, Compensation, and Nominating and Governance Committees, are available free of charge on our website or in print to any shareholder who requests them. We may from time to time provide important disclosures to investors by posting them in the investor information section of our website, as allowed by SEC rules.

GENERAL

We were founded in 1963 as an oil and natural gas contract drilling company. Today, in addition to our drilling operations, we have operations in the exploration and production and mid-stream areas. We operate, manage, and analyze our results of operations through our three principal business segments:

- Contract Drilling – carried out by our subsidiary Unit Drilling Company and its subsidiaries. This segment contracts to drill onshore oil and natural gas wells for others, and for our own account.
- Oil and Natural Gas – carried out by our subsidiary Unit Petroleum Company. This segment explores, develops, acquires, and produces oil and natural gas properties for our own account.
- Mid-Stream – carried out by our subsidiary Superior Pipeline Company, L.L.C. and its subsidiaries. This segment buys, sells, gathers, processes, and treats natural gas for third parties and for our own account.

Each of these companies may conduct operations through subsidiaries of their own.

The following table provides certain information about us as of February 15, 2013:

Number of drilling rigs we own	127
Completed gross wells in which we own an interest	10,068

Number of natural gas treatment plants we own	3
Number of processing plants we own	14
Number of natural gas gathering systems we own	39

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2012 SEGMENT OPERATIONS HIGHLIGHTS

Contract Drilling

- Placed into service in our Rocky Mountain division two new 1,500 horsepower, diesel-electric drilling rigs.
- Refurbished, upgraded, or returned into service 15 drilling rigs after being stacked for use to meet increasing horizontal drilling activity.
- Sold an idle 600 horsepower mechanical drilling rig to an unaffiliated third-party.

Oil and Natural Gas

- Attained net proved oil, NGLs, and natural gas reserves of 150.0 million barrels of oil equivalents (MMBoe), a 29% increase over 2011 reserves.
- Increased net proved oil and NGLs reserves by 35% over 2011.
- Total production of 14.2 MMBoe or an 18% increase over 2011.
- Participated in the drilling of 171 wells.
- Acquired approximately 83,000 net acres with approximately 600 potential horizontal drilling locations primarily in the Granite Wash, Cleveland, and various other plays in western Oklahoma and the Texas Panhandle from Noble Energy, Inc. (Noble).
- Sold our interest in certain Bakken properties representing approximately 35% of our total acreage in the Bakken play. Proceeds, net of related expenses, were $226.6 million.
- Sold certain oil and natural gas assets located in Brazos and Madison Counties, Texas, for approximately $44.1 million.
- Announced a field discovery in our Wilcox play having estimated reserve potential of 229 Bcfe, gross (159 Bcfe, net).

Mid-Stream

- Gas gathered increased from 216 MMbtu per day in 2011 to 289 MMbtu per day in 2012, a 34% increase.
- Gas processed increased from 116 MMbtu per day in 2011 to 166 MMbtu per day in 2012, a 42% increase.
- NGLs sold increased from 412,000 gallons per day in 2011 to 543,000 gallons per day in 2012, a 32% increase.
- Completed the installation of a 45 MMcf per day turbo expander plant at our Hemphill facility increasing our total processing capacity at that facility to approximately 160 MMcf per day.
- Completed the installation of a second gas processing plant at our Cashion facility increasing the total processing capacity of the facility to approximately 45 MMcf per day.
- Completed initial construction of a new gathering system, known as the Bellmon system, and the related installation of a 20 MMcf per day gas processing plant.
- Completed construction of the first phase of a 7-mile gathering system at our Pittsburgh Mills facility located in Allegheny and Butler Counties, Pennsylvania.
- Added an additional 370 miles of pipeline (approximately a 40% increase) and connected 99 new wells to our various gathering systems.
- Acquired four gathering systems as a result of the acquisition from Noble.

FINANCIAL INFORMATION ABOUT SEGMENTS

See Note 16 of our Notes to Consolidated Financial Statements in Item 8 of this report for information with respect to each of our segment's revenues, profits or losses, and total assets.

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CONTRACT DRILLING

General. Our contract drilling business is conducted through Unit Drilling Company and its subsidiary Unit Texas Drilling L.L.C. Through these companies we drill onshore oil and natural gas wells for our own account as well as for a wide range of other oil and natural gas companies. Our drilling operations are mainly located in Oklahoma, Texas, Louisiana, Kansas, Wyoming, Colorado, Utah, Montana, and North Dakota.

The following table identifies certain information concerning our contract drilling operations:

	Year Ended December 31,		
	2012	2011	2010
Number of drilling rigs owned at year end	127.0	127.0	121.0
Average number of drilling rigs owned during year	127.4	123.7	123.9
Average number of drilling rigs utilized	73.9	76.1	61.4
Utilization rate [1]	58 %	61 %	50 %
Average revenue per day [2]	$19,774	$17,520	$14,134
Total footage drilled (feet in 1,000's)	10,551	9,749	7,961
Number of wells drilled	773	742	593

(1) Utilization rate is determined by dividing the average number of drilling rigs used by the average number of drilling rigs owned during the year.

(2) Represents the total revenues minus rental revenue from our contract drilling operations divided by the total number of days our drilling rigs were used minus the rental days during the year.

Description and Location of Our Drilling Rigs. An on-shore drilling rig is composed of major equipment components such as engines, drawworks or hoists, derrick or mast, substructure, pumps to circulate the drilling fluid, blowout preventers, and drill pipe. As a result of the normal wear and tear of operating 24 hours a day, several of the major components of a drilling rig, like engines, mud pumps, and drill pipe, must be replaced or rebuilt on a periodic basis. Other components, like the substructure, mast, and drawworks, can be used for extended periods of time with proper maintenance. We also own additional equipment used in the operation of our drilling rigs, including top drives, skidding systems, large air compressors, trucks, and other support equipment.

The maximum depth capacities of our various drilling rigs range from 5,000 to 40,000 feet. In 2012, 90 of our 127 drilling rigs were used in drilling services.

The following table shows certain information about our drilling rigs (including their distribution) as of February 15, 2013:

Divisions	Contracted Rigs	Non-Contracted Rigs	Total Rigs	Average Rated Drilling Depth (ft)
Mid-Continent	23	12	35	19,386
Woodward	11	6	17	13,853
Panhandle	10	15	25	12,720
Gulf Coast	6	10	16	18,250
Rocky Mountain	19	15	34	17,647
Totals	69	58	127	16,724

Drilling rig utilization steadily increased throughout 2010 and 2011, and began declining throughout 2012 due primarily to drilling efficiencies attained by operators, more acreage in certain plays being held by production, and weakness in NGLs

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prices. Our active drilling rig count at the start of 2010 was 42 drilling rigs and increased to 82 drilling rigs at the end of 2011 and finished out 2012 at 62 drilling rigs.

Mid-Continent, Woodward, and Panhandle - We have long held a strong position and market presence in the mid-continent area of Oklahoma and the Texas Panhandle. This area is commonly referred to as the Anadarko Basin, which also encompasses portions of Kansas. Historically, the Anadarko Basin has been known as a gas producing area, but it is also rich in oil and NGL production. Within this basin during the last several years, operators have focused their operations on the Cana Woodford, Granite Wash, Marmaton and Mississippian horizontal plays. Three of our divisions work in this basin. During 2012, our Mid-Continent, Panhandle, and Woodward divisions averaged 24.0, 10.0, and 11.6 drilling rigs operating, respectively. Our Arkoma division, which operated in the dry gas producing area of eastern Oklahoma, averaged only 1.0 drilling rig operating for 2012. As a result, we consolidated that division into the Mid-Continent division at the end of the year.

Gulf Coast - Our Gulf Coast division provides drilling rigs to the onshore areas of Louisiana, Texas Gulf Coast, East Texas, and South Texas. During 2012, this division averaged 7.2 drilling rigs operating. Within this division, our largest drilling rig, Rig 201, a 4,000 horsepower rig rated to drill to 40,000 feet, is drilling an ultra-deep exploration well for a major oil company in south Louisiana. As part of these operations, Rig 201 established a world record by setting the deepest string of 16” casing for an onshore well. It is anticipated that by the time the well is completed, it will be the deepest onshore well in the state of Louisiana.

Rocky Mountains - Our Rocky Mountain division covers several states, including Colorado, Utah, Wyoming, Montana, and North Dakota. This vast area has produced a number of conventional and unconventional oil and gas fields. Our drilling rig fleet in this division operated an average of 20.2 drilling rigs during 2012. We have drilling rigs operating primarily in the Pinedale Anticline of western Wyoming and the Bakken Shale of North Dakota. One new drilling rig was added to each of these areas during 2012. We ended 2012 with 13.0 drilling rigs working in the Bakken Shale.

At any given time the number of drilling rigs we can work depends on a number of conditions besides demand, including the availability of qualified labor and the availability of needed drilling supplies and equipment. Not surprisingly, the impact of these conditions tends to fluctuate with the demand for our drilling rigs. For 2010, our average utilization rate was 50%, for 2011 it increased to 61%, and for 2012 it decreased slightly to 58%.

The following table shows the average number of our drilling rigs working by quarter for the years indicated:

	2012	2011	2010
First quarter	81.5	70.0	50.9
Second quarter	76.7	73.1	58.1
Third quarter	73.4	78.9	65.4
Fourth quarter	64.0	82.1	70.9

Drilling Rig Fleet. The following table summarizes the changes made to our drilling rig fleet in 2012. A more complete discussion of the changes follows the table:

Drilling rigs owned at December 31, 2011	127	
Drilling rigs sold/removed from service [(1)]	(2	)
Drilling rigs purchased	—	
Drilling rigs constructed	2	
Total drilling rigs owned at December 31, 2012	127	

(1) During the third-quarter of 2012, we had a fire on one of our drilling rigs.

Dispositions, Acquisitions, and Construction. During the first half of 2010, our contract drilling segment sold eight of its idle mechanical drilling rigs to an unaffiliated third party. These drilling rigs ranged in horsepower from 800 to 1,000. Proceeds from the sale were $23.9 million with a gain of $5.7 million which was recorded in the first quarter 2010. The proceeds were used to refurbish and upgrade existing drilling rigs in our fleet allowing those drilling rigs to be used in

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horizontal drilling operations. We also placed into service in our Rocky Mountain division a 1,500 horsepower, diesel-electric drilling rig that previously had been placed on hold during 2009 by our customer.

In September 2010, we entered into a contract with an unaffiliated third-party under which we conveyed three of our idle mechanical drilling rigs and, in exchange, we received a 1,200 horsepower electric drilling rig and $5.3 million. The three drilling rigs sold ranged in horsepower from 650 to 1,000. The transaction closed in October and resulted in a gain of $3.5 million.

At the end of 2010, we began constructing five new 1,500 horsepower, diesel-electric drilling rigs. All of these drilling rigs are now operational and located in the Bakken Shale in North Dakota.

During 2011, we were awarded two additional new build drilling rig contracts for 1,500 horsepower, diesel-electric drilling rigs. One was placed into service during the fourth quarter of 2011 and the other was placed in service during the first quarter of 2012, both in Wyoming.
During the first quarter of 2012, we sold an idle 600 horsepower mechanical drilling rig to an unaffiliated third-party. Additionally, in the second quarter we placed another new 1,500 horsepower, diesel-electric drilling rig to work in North Dakota under a three year contract.
During the third quarter of 2012, we had a fire on one of our drilling rigs located in the mid-continent region. The net book value of the damaged equipment was $3.2 million. We expect that all of the net book value of the damaged equipment will be recoverable from insurance proceeds. As a result of this loss, this segment now has 127 drilling rigs in its fleet. No personnel were injured in this incident.

Historically, our contract drilling segment has experienced a greater demand for natural gas drilling as opposed to drilling for oil and NGLs. However, with the current weakened natural gas market, operators are focusing on drilling for oil and NGLs. Today, approximately 99% of our working drilling rigs are drilling for oil or NGLs. Of those, approximately 97% are drilling horizontal or directional wells.

Drilling Contracts. Our drilling contracts are generally obtained through competitive bidding on a well by well basis. Contract terms and payment rates vary depending on the type of contract used, the duration of the work, the equipment and services supplied, and other matters. We pay certain operating expenses, including the wages of our drilling personnel, maintenance expenses, and incidental drilling rig supplies and equipment. The contracts are usually subject to early termination by the customer subject to the payment of a fee. Our contracts also contain provisions regarding indemnification against certain types of claims involving injury to persons, property, and for acts of pollution. The specific terms of these indemnifications are subject to negotiation on a contract by contract basis.

The type of contract used determines our compensation. Contracts are generally one of three types: daywork; footage; or turnkey. Additional compensation may be acquired for special risks and unusual conditions. Under a daywork contract, we provide the drilling rig with the required personnel and the operator supervises the drilling of the well. Our compensation is based on a negotiated rate to be paid for each day the drilling rig is used. Footage contracts usually require us to bear some of the drilling costs in addition to providing the drilling rig. We are paid on completion of the well at a negotiated rate for each foot drilled. We did not have any footage contracts in 2012 or 2011 and we drilled four wells under a footage contract in 2010.

Under turnkey contracts we drill the well to a specified depth for a set amount and provide most of the required equipment and services. We bear the risk of drilling the well to the contract depth and are paid when the contract provisions are completed. We may incur losses if we underestimate the costs to drill the well or if unforeseen events occur that increase our costs or result in the loss of the well. We have not worked under a turnkey contract during the last three years. With the exception of the footage contracts noted above, all of our work during the last three years was under daywork contracts. Because market demand for our drilling rigs as well as the desires of our customers determine the types of contracts we use, we cannot predict when and if a part of our drilling will be conducted under footage or turnkey contracts.

The majority of our contracts are on a well-to-well basis, with the rest under term contracts. Term contracts range from six months to three years and, depending on the contract, the rates can either be fixed throughout the term or allow for periodic adjustments.

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Customers. During 2012, QEP Resources, Inc. and Kodiak Oil and Gas Corp. were our largest drilling customers accounting for approximately 15% and 10%, respectively, of our total contract drilling revenues. Our work for these customers was under multiple contracts and our business was not substantially dependent on any of these individual contracts. Consequently, none of these contracts on their own were considered to be material. No other third party customer accounted for 10% or more of our contract drilling revenues.

Our contract drilling segment also provides drilling services for our oil and natural gas segment. During 2012, 2011, and 2010, we drilled 78, 81, and 75 wells, respectively, or 10%, 11%, and 13%, respectively, of the total wells drilled by our drilling segment. Depending on the timing of the drilling services performed on our properties those services may be deemed, for financial reporting purposes, to be associated with the acquisition of an ownership interest in the property. Revenues and expenses for these services are eliminated in our income statement, with any profit recognized reducing our investment in our oil and natural gas properties. The contracts for these services are issued under the same conditions and rates as the contracts entered into with unrelated third parties. We eliminated revenue of $49.6 million, $52.2 million, and $40.1 million during 2012, 2011, and 2010, respectively, from our contract drilling segment and eliminated the associated operating expense of $34.1 million, $32.6 million, and $31.0 million during 2012, 2011, and 2010, respectively, yielding $15.5 million, $19.6 million, and $9.1 million during 2012, 2011, and 2010, respectively, as a reduction to the carrying value of our oil and natural gas properties.

OIL AND NATURAL GAS

General. We began to develop our exploration and production operations in 1979. Today, our wholly owned subsidiary, Unit Petroleum Company conducts our exploration and production activities. Our producing oil and natural gas properties, undeveloped leaseholds, and related assets are located mainly in Oklahoma and Texas, and to a lesser extent, in Arkansas, Colorado, Kansas, Louisiana, Mississippi, Montana, New Mexico, North Dakota, Pennsylvania, Wyoming, and a small portion in Canada.

When we are the operator of a property, we generally attempt to use a drilling rig owned by our contract drilling segment, and we use our mid-stream segment to gather our gas if circumstances warrant it.

The following table presents certain information regarding our oil and natural gas operations as of December 31, 2012:

Our Divisions/Area	Number of Gross Wells	Number of Net Wells	Number of Gross Wells in Process	Number of Net Wells in Process	2012 Average Net Daily Production Natural Gas (Mcf)	Oil (Bbls)	NGLs (Bbls)
West division (consists principally of the Rocky Mountain region, New Mexico, Western and Southern Texas, and the Gulf Coast region)	3,239	525.39	4	2.96	32,324	2,926	2,344
East division (consists principally of the Appalachian region, Arkansas, East Texas, Northern Louisiana, and Eastern Oklahoma)	1,693	523.79	1	0.01	32,529	43	62
Central division (consists principally of Kansas, Western Oklahoma, and the Texas Panhandle)	5,130	1,774.89	9	5.16	68,835	5,990	5,234

Total	10,062	2,824.07	14	8.13	133,688	8,959	7,640

As of December 31, 2012, we did not have any significant water floods, pressure maintenance operations, or any other material operations that were in process.

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Description and Location of Our Core Operations

West division. In our Wilcox play, located primarily in Polk, Tyler, and Hardin Counties, Texas, we operated and completed 11 gross wells in 2012 with an average working interest of 88% and a success rate of 82%. Three of the 11 wells were completed in our "Gilly" Lower Wilcox field bringing the total number of wells completed in that field to five at year end 2012. Approximately 18% or 30 net Bcfe of the anticipated 168 net Bcfe (242 gross Bcfe) potential reserves are booked as proved producing or proved behind pipe at year end 2012. For 2013, we plan to run one of our drilling rigs which should drill approximately 12 gross wells at an approximate net cost of $60 million. Seven of the 12 wells are planned to be drilled in the "Gilly" Lower Wilcox Field and the remaining five wells will be drilled on other Wilcox prospects.

East division. Over the last several years, activity in our East Division has been limited due to low gas prices since this area does not generally have oil or NGLs associated with the gas.

Central division. We recently acquired approximately 105,000 net acres located primarily in south central Kansas in the developing Mississippian play. Unit drilled its first horizontal well in Reno County, Kansas in the second quarter 2012 to a total measured depth of 8,115 feet including 3,850 feet of lateral. First production occurred in May 2012 with an average peak 30 day rate of 352 Boe per day consisting of 315 barrels of oil per day, 12 barrels of NGLs per day, and 150 Mcf of natural gas per day. The production components were approximately 89% oil, 3% NGLs, and 8% natural gas. Based on the production profile of this well, the reserve range estimate for a well in our Kansas Mississippian play would range somewhere between 125 MBoe to 180 MBoe. Using this estimated range and a completed well cost of $3.0 million along with flat pricing of $90 oil, $30 NGLs, and $3.25 natural gas, the typical Mississippian well would have a calculated rate of return (ROR) of approximately 30% to 66%. In addition to the initial well, we drilled three more horizontal Mississippian wells during 2012. Two of the wells had first sales in late December 2012, and the third is waiting on pipeline connection. In the first quarter of 2013, we plan to drill three additional wells before suspending drilling until pipeline infrastructure can be installed, which is scheduled for mid-year 2013. The estimated completion date for the pipeline is June 2013. Current plans are to move one of our drilling rigs back in the Mississippian play starting in July 2013 and possibly adding a second drilling rig in September 2013. For 2013, we anticipate having first sales on approximately 13 gross wells and spending approximately $40 million for drilling and completion in our Mississippian play.

During 2012, we drilled 32 gross wells with an average working interest of 84% in our Marmaton horizontal oil play, located in Beaver County, Oklahoma. Thirty of the wells were short laterals with approximately 4,500 feet of lateral length and two of the wells were extended laterals with approximately 9,700 feet of lateral length. The net production from our Marmaton play for the fourth quarter of 2012 averaged 3,424 barrels of oil per day, 528 barrels of NGLs per day, and 1,775 Mcf of natural gas per day, an increase of 15% over the third quarter 2012 and a 61% year-over-year increase between 2012 and 2011. Included in the year-end reserve calculations are adjustments taken for wellbore communication that some of the wells have experienced. We have adjusted our drilling program to address this issue. For 2013, we anticipate running a two drilling rig program in this play that should result in approximately 40 gross wells at an approximate net cost of $90 million. Due to current well spacing limitations associated with drilling extended lateral wells, the majority of 2013 wells are anticipated to be drilled as short lateral wells. We currently have leases on approximately 112,000 net acres in this play with about 44% of the leasehold held by production.

In our Granite Wash (GW) play located in the Texas Panhandle, we drilled and operated 29 gross horizontal wells during 2012 with an average working interest of 87%. The net production from our GW play for the fourth quarter of 2012 averaged 1,822 barrels of oil per day, 4,988 barrels of NGLs per day, and 46.2 MMcf of natural gas per day, or an equivalent rate of 87.0 MMcfe per day, an increase of 43% over the third quarter 2012 and a 41% year-over-year increase between 2012 and 2011. We expect to work four to six of our drilling rigs drilling horizontal wells in both the newly acquired Noble leasehold and our existing leasehold in 2013, which equates to approximately 37 operated gross GW wells at an approximate net cost of $150 million. We currently own leases on approximately 46,000 net acres with about 80% of the leasehold held by production.

Dispositions and Acquisitions. There were no material dispositions during 2010 or 2011. In September 2012, we sold our interest in certain Bakken properties (representing approximately 35% of our total acreage in the Bakken play). The proceeds, net of related expenses, were $226.6 million. In addition, we sold certain oil and natural gas assets located in Brazos and Madison Counties,Texas, for approximately $44.1 million. Both dispositions were accounted for as adjustments to the full cost pool with no gain or loss recognized.

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On June 2, 2010, we completed an acquisition of oil and natural gas properties from certain unaffiliated parties in an effort to explore and develop more oil rich plays. The properties were purchased for approximately $73.7 million in cash, after post-closing adjustments. The purchase price allocation was $48.7 million for proved properties and $25.0 million for undeveloped leasehold not being amortized. The acquisition included approximately 45,000 net leasehold acres and 10 producing oil wells. This acquisition targeted the Marmaton horizontal oil play located mainly in Beaver County, Oklahoma.

On July 20, 2011, we acquired certain producing properties from an unaffiliated seller for approximately $12.3 million in cash, after post-closing adjustments, consisting of 30 operated wells and 59 non-operated well interests located in Beaver, Harper, and Ellis Counties, Oklahoma and Lipscomb County, Texas. The purchase price allocation was $8.4 million for proved properties and $3.9 million for acreage. The acquisition also included in excess of 12,000 net acres held by production available for future development.

On August 31, 2011, we acquired certain producing oil and gas properties for $30.5 million in cash from an unaffiliated seller. Included in the acquisition were more than 500 wells located principally in the Oklahoma Arkoma Woodford and Hartshorne Coal plays along with other properties located throughout Oklahoma and Texas. The acquisition also included approximately 55,000 net acres of which 96% was held by production.

On September 17, 2012, we closed our acquisition of certain oil and natural gas assets from Noble . After final closing adjustments, the acquisition included approximately 83,000 net acres primarily in the Granite Wash, Cleveland, and various other plays in western Oklahoma and the Texas Panhandle. The adjusted amount paid was $592.6 million. As of April 1, 2012, the effective date of the Noble acquisition, the estimated proved reserves of the acquired properties were 44 MMBoe, The acquisition added approximately 24,000 net leasehold acres to our Granite Wash core area in the Texas Panhandle with significant potential including approximately 600 possible future horizontal drilling locations. The total acreage acquired in other plays in western Oklahoma and the Texas Panhandle was approximately 59,000 net acres and was characterized by high working interest and operatorship, 95% of which was held by production. We also received four gathering systems as part of the transaction and other miscellaneous assets.

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Well and Leasehold Data. The following tables identify certain information regarding our oil and natural gas exploratory and development drilling operations:

	Year Ended December 31,					
	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Wells drilled:						
Exploratory:						
Oil:						
West division	1	1.00	—	—	3	1.41
East division	—	—	—	—	—	—
Central division	1	1.00	—	—	1	1.00
Total oil	2	2.00	—	—	4	2.41
Natural gas:						
West division	3	2.49	5	4.13	4	4.00
East division	—	—	—	—	—	—
Central division	—	—	—	—	1	0.05
Total natural gas	3	2.49	5	4.13	5	4.05
Dry:						
West division	1	1.00	7	6.50	5	4.12
East division	—	—	—	—	—	—
Central division	—	—	—	—	—	—
Total dry	1	1.00	7	6.50	5	4.12
Total exploratory	6	5.49	12	10.63	14	10.58
Development:						
Oil:						
West division	29	4.10	21	4.57	25	4.69
East division	—	—	—	—	—	—
Central division	71	34.04	56	32.81	43	25.90
Total oil	100	38.14	77	37.38	68	30.59
Natural gas:						
West division	7	4.44	9	6.26	13	10.85
East division	2	0.76	9	4.65	19	11.47
Central division	55	30.45	44	18.32	42	18.22
Total natural gas	64	35.65	62	29.23	74	40.54
Dry:						
West division	1	0.80	3	2.03	4	1.51
East division	—	—	1	1.00	1	0.36
Central division	—	—	5	2.15	6	3.94
Total dry	1	0.80	9	5.18	11	5.81
Total development	165	74.59	148	71.79	153	76.94
Total wells drilled	171	80.08	160	82.42	167	87.52

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	Year Ended December 31,					
	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Wells producing or capable of producing:						
Oil:						
West division	2,076	178.43	2,074	183.50	2,052	178.85
East division	54	3.17	54	3.17	52	2.58
Central division	807	382.34	631	273.31	552	234.05
Total oil	2,937	563.94	2,759	459.98	2,656	415.48
Natural gas:						
West division	1,109	330.19	1,182	335.90	1,167	324.33
East division	1,632	519.62	1,636	522.15	1,086	290.04
Central division	4,245	1,362.87	3,097	683.08	2,927	611.05
Total natural gas	6,986	2,212.68	5,915	1,541.13	5,180	1,225.42
Total	9,923	2,776.62	8,674	2,001.11	7,836	1,640.90

As of February 15, 2013, we are currently drilling or participating in 15 gross (8.40 net) wells started during 2013.

Cost incurred for development drilling includes $123.4 million, $111.4 million, and $84.6 million in 2012, 2011, and 2010, respectively, to develop booked proved undeveloped oil and natural gas reserves.

The following table summarizes our leasehold acreage at December 31, 2012:

	Year Ended December 31, 2012					
	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net (1)	Gross	Net
West division	300,646	99,769	184,332	98,115	484,978	197,884
East division	265,514	99,034	120,374	41,935	385,888	140,969
Central division	739,850	269,647	403,518	268,135	1,143,368	537,782
Total	1,306,010	468,450	708,224	408,185	2,014,234	876,635

(1) Approximately 72% (West – 79%; East – 46%; and Central – 74%) of the net undeveloped acres are covered by leases that will expire in the years 2013—2015 unless drilling or production extends the terms of those leases.

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Price and Production Data. The following tables identify the average sales price, production volumes and average production cost per equivalent barrel for our oil, NGLs, and natural gas production for the years indicated:

	Year Ended December 31,		
	2012	2011	2010
Average sales price per barrel of oil produced:			
Price before hedging	$90.19	$93.49	$76.65
Effect of hedging	2.41	(6.31)	(7.13)
Price including hedging	$92.60	$87.18	$69.52
Average sales price per barrel of NGLs produced:			
Price before hedging	$30.70	$44.44	$36.96
Effect of hedging	0.88	(0.80)	0.08
Price including hedging	$31.58	$43.64	$37.04
Average sales price per Mcf of natural gas produced:			
Price before hedging	$2.53	$3.78	$4.05
Effect of hedging	0.84	0.48	1.57
Price including hedging	$3.37	$4.26	$5.62

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	Year Ended December 31,		
	2012	2011	2010
Oil production (MBbls):			
West division	1,071	893	729
East division	16	12	14
Central division:			
Mendota field	497	262	149
All other central division fields	1,695	1,344	629
Total central division	2,192	1,606	778
Total oil production (MBbls)	3,279	2,511	1,521
NGLs production (MBbls):			
West division	858	798	627
East division	23	5	4
Central division:			
Mendota field	1,128	691	494
All other central division fields	787	745	424
Total central division	1,915	1,436	918
Total NGLs production (MBbls)	2,796	2,239	1,549
Natural gas production (MMcf):			
West division	11,831	11,774	10,946
East division	11,906	12,768	14,029
Central division:			
Mendota field	8,957	4,887	4,050
All other central division fields	16,236	14,675	11,731
Total central division	25,193	19,562	15,781
Total natural gas production (MMcf)	48,930	44,104	40,756
Total production (MBoe):			
West division	3,901	3,653	3,180
East division	2,023	2,145	2,356
Central division:			
Mendota field	3,118	1,768	1,318
All other central division fields	5,188	4,535	3,009
Total central division	8,306	6,303	4,327
Total production (MBoe)	14,230	12,101	9,863
Average production cost per equivalent Bbl (1)	$7.00	$6.90	$6.54

(1) Excludes ad valorem taxes and gross production taxes.

Our Mendota field, located in the Granite Wash play, includes 19%, 22%, and 20%, respectively of our total proved reserves in 2012, 2011, and 2010, respectively, expressed on an oil equivalent barrels basis, and is the only field that is greater than 15% of our proved reserves.

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Oil, NGLs, and Natural Gas Reserves. The following table identifies our estimated proved developed and undeveloped oil, NGLs, and natural gas reserves:

	Year Ended December 31, 2012			
	Natural Gas (MMcf)	Oil (MBbls)	NGLs (MBbls)	Total Proved Reserves (MBoe)
Proved developed:				
West division	73,177	3,837	4,536	20,569
East division	101,267	92	169	17,139
Central division	278,400	12,512	20,952	79,864
Total proved developed	452,844	16,441	25,657	117,572
Proved undeveloped:				
West division	12,089	1,086	398	3,499
East division	9,324	—	—	1,554
Central division	81,390	4,471	9,111	27,147
Total proved undeveloped	102,803	5,557	9,509	32,200
Total proved	555,647	21,998	35,166	149,772

Oil, NGLs, and natural gas reserves cannot be measured exactly. Estimates of oil, NGLs, and natural gas reserves require extensive judgments of reservoir engineering data and are generally less precise than other estimates made in connection with financial disclosures. We use Ryder Scott Company L.P. (Ryder Scott), independent petroleum consultants, to audit the reserves prepared by our reservoir engineers. Ryder Scott has been providing petroleum consulting services throughout the world for over seventy years. Their summary report is attached as Exhibit 99.1 to this Form 10-K. The wells or locations for which reserve estimates were audited were taken from reserve and income projections prepared by us as of December 31, 2012 and comprised the top 82% of the total proved developed discounted future net income and 87% of the total proved undeveloped discounted future net income (based on the unescalated pricing policy of the SEC).

Our Reservoir Engineering department is responsible for reserve determination for the wells in which we have an interest. Their primary objective is to estimate the wells' future reserves and future net value to us. Data is incorporated from multiple sources including geological, production engineering, marketing, production, land, and accounting departments. The engineers are responsible for reviewing this information for accuracy as it is incorporated into the reservoir engineering database. Our internal audit group then checks to confirm the correctness of the data transfer. New well reserve estimates are provided to management as well as the respective operational divisions for additional scrutiny. Major reserve changes on existing wells are reviewed on a regular basis with the operational divisions to confirm correctness and accuracy. As the external audit is being completed by Ryder Scott, the reservoir department performs a final review of all properties for accuracy of forecasting.

Technical Qualifications

Ryder Scott – Mr. Fred P. Richoux is the primary technical person in charge on behalf of Ryder Scott for their audit of our reserves.

Mr. Richoux, an employee of Ryder Scott since 1978, is the President and member of the Board of Directors at Ryder Scott. He is responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide as well as other administrative functions at the Company. Before joining Ryder Scott, Mr. Richoux served in a number of engineering positions with Phillips Petroleum Company.

Mr. Richoux earned a Bachelor of Science degree in Electrical Engineering from the University of Louisiana at Lafayette and is a registered Professional Engineer in the State of Texas and the Province of Alberta. He is also a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

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In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Richoux fulfills.

Based on his educational background, professional training and more than 45 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Richoux has attained the professional qualifications as a Reserves Estimator (requires appropriate degree and/or is registered as Professional Engineer and a has minimum of 3 years experience in the estimation and evaluation of reserves) and Reserves Auditor (requires appropriate degree and/or is registered as Professional Engineer and a has minimum of 10 years experience in the estimation and evaluation of reserves of which at least 5 years of such experience is being in responsible charge of the estimation and evaluation of reserves) set forth in Article III of the “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information” promulgated by the Society of Petroleum Engineers as of February 19, 2007. For more information regarding Mr. Richoux’s geographic and job specific experience, please refer to the Ryder Scott website at http://www.ryderscott.com/Experience/Employees.

The Company – Responsibility for overseeing the preparation of our reserve report is shared by our reservoir engineers Trenton Mitchell and Robert Lyon.

Mr. Mitchell earned a Bachelor of Science degree in Petroleum Engineering from Texas A&M University in 1994. He has been an employee of Unit since 2002. Initially, he was the Outside Operated Engineer and since 2003 he has served in the capacity of Reservoir Engineer and in 2010 he was promoted to Manager of Reservoir Engineering. Before joining Unit, he served in a number of engineering field and technical support positions with Schlumberger Well Services in their pumping services segment (formerly Dowell Schlumberger). He obtained his Professional Engineer registration from the State of Oklahoma in 2004 and has been a member of Society of Petroleum Engineers (SPE) since 1991.

Mr. Lyon received a Bachelor of Science degree in Petroleum Engineering from the University of Tulsa in 1972 and has spent 33 of his 40 years in the industry directly involved in reserve calculation work. Included in this time were 15 years working for petroleum consulting firms Raymond F. Kravis and Associates and Southmayd and Associates performing independent reserve appraisals and audits for corporations and individuals. He joined Unit in 1996 and has shared responsibility for preparation of the company’s reserve report since that time. Mr. Lyon is a registered professional engineer in the State of Oklahoma and a member of the SPE.

As part of the continuing education requirement for maintaining their professional licenses Mr. Mitchell and Mr. Lyon have attended various seminars and forums to enhance their understanding of current standards & issues for reserves presentation. These forums have included those sponsored by various professional societies and professional service firms including Ryder Scott.

Definitions and Other.   Proved oil, NGLs, and natural gas reserves, as defined in SEC Rule 4-10(a), are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations – before the time the contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

The area of the reservoir considered as proved includes:
- The area identified by drilling and limited by fluid contacts, if any, and
-

Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geosciences and engineering data.

In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geosciences, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty.

Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geosciences, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

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Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

- Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole;
- The operation of an installed program in the reservoir or other evidence using reliable technology establishes reasonable certainty of the engineering analysis on which the project or program was based; and
- The project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price is the average price during the 12-month period before the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first day of month price for each month within the period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions.

Proved undeveloped oil, NGLs, and natural gas reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for completion. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time. Under no circumstances can estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Proved Undeveloped Reserves. As of December 31, 2012, we had approximately 151 gross proved undeveloped wells all of which we plan to develop within five years of initial disclosure at a net estimated cost of approximately $389.6 million. The future estimated development costs necessary to develop our proved undeveloped oil and natural gas reserves in the United States for the years 2013—2017, as disclosed in our December 31, 2012 oil and natural gas reserve report, are $159.5 million, $178.4 million, $19.9 million, $11.0 million, and $20.8 million, respectively. Our proved undeveloped reserves reported at December 31, 2012 did not include reserves that we did not expect to develop within five years of initial disclosure of such reserves. During 2012, we converted 36 proved undeveloped wells into proved developed wells at a cost of approximately $123.4 million. The proved undeveloped reserves that were converted to proved developed reserves during 2012, represented 1.8 MMBls of oil, 3.0 MMBls of NGLs, and 23.9 Bcf of natural gas.

Our estimated proved reserves and the standardized measure of discounted future net cash flows of the proved reserves at December 31, 2012, 2011, and 2010, the changes in quantities and standardized measure of those reserves for the three years then ended, are shown in the Supplemental Oil and Gas Disclosures included in Item 8 of this report.

Contracts. Our oil production is sold at or near our wells under purchase contracts at prevailing prices in accordance with arrangements customary in the oil industry. Our natural gas production is sold to intrastate and interstate pipelines as well as to independent marketing firms under contracts with terms generally ranging from one month to a year. Few of these contracts contain provisions for readjustment of price as most of them are market sensitive.

Customers. During 2012, sales to Valero Energy Corporation accounted for 26% of our oil and natural gas revenues. There was no other company that accounted for more than 10% of our oil and natural gas revenues. During 2012, our mid-stream segment purchased $68.2 million of our natural gas and NGLs production and provided gathering and transportation services of $5.1 million. Intercompany revenue from services and purchases of production between our mid-stream segment and our oil and natural gas segment has been eliminated in our consolidated financial statements. In 2011 and 2010, we eliminated intercompany revenues of $76.1 million and $46.8 million, respectively, attributable to the intercompany purchase of our production of natural gas and NGLs as well as gathering and transportation services.

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MID-STREAM

General. Our mid-stream operations are conducted through Superior Pipeline Company L.L.C. Its operations consist of buying, selling, gathering, processing, and treating natural gas. In addition, it operates three natural gas treatment plants, 14 processing plants, 39 active gathering systems, and approximately 1,300 miles of pipeline. Superior and its subsidiaries operate in Oklahoma, Texas, Kansas, Pennsylvania, and West Virginia.

The following table presents certain information regarding our mid-stream segment for the years indicated:

	Year Ended December 31,		
	2012	2011	2010
Gas gathered—MMBtu/day	288,799	215,805	183,867
Gas processed—MMBtu/day	165,511	116,161	82,175
NGLs sold—gallons/day	542,578	412,064	271,360

Dispositions and Acquisitions. This segment did not have any significant dispositions or acquisitions during 2011 or 2010.

On September 17, 2012, we closed on the acquisition of certain oil and natural gas assets from Noble. Included were four gathering systems that were transferred into our mid-stream segment. The cost for the systems was $18.7 million.

In December 2012, our mid-stream segment had a $1.2 million write down of our Erick system. There was no volume from the wells connected to this system, the compressor and related surface equipment have been removed from this location and there is no future activity anticipated from this gathering system.

Contracts. Our mid-stream segment provides its customers with a full range of gathering, processing, and treating services. These services are usually provided to each customer under long-term contracts (more than one year), but we do have some short-term contracts as well. Our customer agreements include the following types of contracts:

- Fee-Based Contracts. These contracts provide for a set fee for gathering and transporting raw natural gas. Our mid-stream's revenue is a function of the volume of natural gas that is gathered or transported and is not directly dependent on the value of the natural gas. For the year ended December 31, 2012, 39% of our mid-stream segment's total volumes and 25% of its operating margins (as defined below) were under fee-based contracts.
- Percent of Proceeds Contracts (POP). These contracts provide for our mid-stream segment to retain a negotiated percentage of the sale proceeds from residue natural gas and NGLs it gathers and processes, with the remainder being remitted to the producer. In this arrangement, Superior and the producers are directly dependent on the volume of the commodity and its value; Superior owns a percentage of that commodity and is directly subject to fluctuations in its market value. For the year ended December 31, 2012, 59% of our mid-stream segment's total volumes and 69% of operating margins (as defined below) were under POP contracts.
- Percent of Index Contracts (POI). Under these contracts our mid-stream's segment, as the processor, purchases raw well-head natural gas from the producer at a stipulated index price and, after processing the natural gas, sells the processed residual gas and the produced NGLs to third parties. Our mid-stream segment is subject to the economic risk (processing margin risk) that the aggregate proceeds from the sale of the processed natural gas and the NGLs could be less than the amount paid for the unprocessed natural gas. For the year ended December 31, 2012, 2% of our mid-stream segment's total volumes and 6% of operating margins (as defined below) were under POI contracts.

For each of the above contracts, operating margin is defined as total operating revenues less operating expenses and does not include depreciation and amortization, general and administrative expenses, interest expense, or income taxes.

Customers. During 2012, ONEOK and Gavilon, LLC accounted for approximately 54% and 10%, respectively, of our mid-stream revenues. We believe that if we lost one or both of these identified customers, there are other customers available to purchase our gas and NGLs.

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VOLATILE NATURE OF OUR BUSINESS

The prevailing prices for oil, NGLs, and natural gas significantly affect our revenues, operating results, cash flow as well as our ability to grow our operations. Historically, oil, NGLs, and natural gas prices have been volatile and we expect them to continue to be so. For each of the periods indicated, the following table shows the highest and lowest average prices our oil and natural gas segment received for its sales of oil, NGLs, and natural gas without taking into account the effect of our hedging activity:

	Oil Price per Bbl		NGLs Price per Bbl		Natural Gas Price per Mcf	
Quarter	High	Low	High	Low	High	Low
2012:						
Fourth	$87.01	$84.39	$34.82	$32.42	$3.57	$2.54
Third	$90.04	$82.69	$24.07	$18.02	$2.78	$2.19
Second	$100.63	$76.35	$34.65	$24.65	$2.34	$1.65
First	$104.32	$97.31	$39.77	$36.04	$2.80	$2.17
2011:						
Fourth	$97.26	$86.63	$46.16	$40.57	$3.46	$3.16
Third	$96.90	$85.68	$47.08	$45.44	$4.30	$3.68
Second	$107.87	$95.78	$49.43	$44.60	$4.04	$3.83
First	$99.77	$86.14	$41.66	$38.35	$4.11	$3.53
2010:						
Fourth	$85.37	$78.20	$43.34	$38.01	$4.00	$2.87
Third	$72.69	$72.23	$33.05	$29.15	$4.43	$3.12
Second	$81.18	$71.19	$36.20	$31.29	$3.99	$3.37
First	$78.08	$73.83	$43.39	$41.50	$5.57	$4.47

Prices for oil, NGLs, and natural gas are subject to wide fluctuations in response to relatively minor changes in the actual or perceived supply of and demand for oil and natural gas, market uncertainty, and a variety of additional factors that are beyond our control, including:

- political conditions in oil producing regions, including the Middle East, Nigeria, and Venezuela;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree on prices and their ability to maintain production quotas;
- the price of foreign oil imports;
- imports of liquefied natural gas;
- actions of governmental authorities;
- the domestic and foreign supply of oil, NGLs, and natural gas;
- the level of consumer demand;
- United States storage levels of natural gas;
- weather conditions;
- domestic and foreign government regulations;
- the price, availability, and acceptance of alternative fuels;
- volatility in ethane prices causing rejection of ethane as part of the liquids processed stream; and
- overall economic conditions.

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These factors and the volatile nature of the energy markets make it impossible to predict with any certainty the future prices of oil, NGLs, and natural gas. You are encouraged to read the Risk Factors discussed in Item 1A of this report for additional risks that can impact our operations.

Our contract drilling operations are dependent on the level of demand in our operating markets. Both short-term and long-term trends in oil, NGLs, and natural gas prices affect demand. Because oil, NGLs, and natural gas prices are volatile, the level of demand for our services can also be volatile.

Our mid-stream operations provide us greater flexibility in delivering our (and other parties) natural gas and NGLs from the wellhead to major natural gas and NGLs pipelines. Margins received for the delivery of these natural gas and NGLs are dependent on the price for oil, natural gas, and NGLs and the demand for natural gas and NGLs in our area of operations. If the price of NGLs falls without a corresponding decrease in the cost of natural gas, it may become uneconomical to us to extract certain NGLs. The volumes of natural gas and NGLs processed are highly dependent on the volume and Btu content of the natural gas and NGLs gathered.

It is possible that the current industry shift in drilling for oil and NGLs may at some point impact future natural gas availability as well as prices for natural gas. In addition, the increasing availability of oil and NGLs may impact the price for these products if supply was to exceed demand.

COMPETITION

All of our businesses are highly competitive and price sensitive. Competition in the contract drilling business traditionally involves factors such as demand, price, efficiency, condition of equipment, availability of labor and equipment, reputation, and customer relations.

Our continued drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers, and other professionals. Competition for these professionals can be extremely intense, particularly when the industry is experiencing favorable conditions.

Our oil and natural gas operations likewise encounter strong competition from other oil and natural gas companies. Many of these competitors have greater financial, technical, and other resources than we do and have more experience than we do in the exploration for and production of oil and natural gas.

Our mid-stream segment competes with purchasers and gatherers of all types and sizes, including those affiliated with various producers, other major pipeline companies, as well as independent gatherers for the right to purchase natural gas and NGLs, build gathering and processing systems, and deliver the natural gas and NGLs once the gathering and processing systems are established. The principal elements of competition include the rates, terms and availability of services, reputation, and the flexibility and reliability of service.

OIL AND NATURAL GAS PROGRAMS AND CONFLICTS OF INTEREST

Unit Petroleum Company serves as the general partner of 16 oil and natural gas limited partnerships. Three of these partnerships were formed for investment by third parties and 13 (the employee partnerships) were formed to allow our employees and directors the opportunity to participate with Unit Petroleum Company in its operations. The partnerships formed for use in connection with third party investments were formed in 1984 and 1986. One employee partnership has been formed each year beginning with 1984 and ending with 2011.

The employee partnerships formed in 1984 through 1999 have been combined into a single consolidated partnership. The employee partnerships each have a set annual percentage (ranging from 1% to 15%) of our interest that the partnership acquires in most of the oil and natural gas wells we drill or acquire for our own account during the year in which the partnership was formed. The total interest the participants have in our oil and natural gas wells by participating in these partnerships does not exceed one percent of our interest in the wells.

Under the terms of our partnership agreements, the general partner has broad discretionary authority to manage the business and operations of the partnership, including the authority to make decisions regarding the partnership's participation in a drilling location or a property acquisition, the partnership's expenditure of funds, and the distribution of funds to partners. Because the business activities of the limited partners and the general partner are not the same, conflicts of interest will exist

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and it is not possible to entirely eliminate these conflicts. Additionally, conflicts of interest may arise when we are the operator of an oil and natural gas well and also provide contract drilling services. In these cases, the drilling operations are conducted under drilling contracts containing terms and conditions comparable to those contained in our drilling contracts with non-affiliated operators. We believe we fulfill our responsibility to each contracting party and comply fully with the terms of the agreements which regulate these conflicts.

These partnerships are further described in Notes 2 and 10 to the Consolidated Financial Statements in Item 8 of this report.

EMPLOYEES

As of February 15, 2013, we had approximately 1,786 employees in our contract drilling segment, 286 employees in our oil and natural gas segment, 126 employees in our mid-stream segment, and 111 in our general corporate area. None of our employees are members of a union or labor organization nor have our operations ever been interrupted by a strike or work stoppage. We consider relations with our employees to be satisfactory.

GOVERNMENTAL REGULATIONS

Our business depends on the demand for services from the oil and natural gas exploration and development industry, and therefore our business can be affected by political developments and changes in laws and regulations that control or curtail drilling for oil and natural gas for economic, environmental, or other policy reasons.

Various state and federal regulations affect the production and sale of oil and natural gas. All states in which we conduct activities impose varying restrictions on the drilling, production, transportation, and sale of oil and natural gas.

Under the Natural Gas Act of 1938, the Federal Energy Regulatory Commission (the FERC) regulates the interstate transportation and the sale in interstate commerce for resale of natural gas. The FERC's jurisdiction over interstate natural gas sales has been substantially modified by the Natural Gas Policy Act under which the FERC continued to regulate the maximum selling prices of certain categories of gas sold in "first sales" in interstate and intrastate commerce. Effective January 1, 1993, however, the Natural Gas Wellhead Decontrol Act (the Decontrol Act) deregulated natural gas prices for all "first sales" of natural gas. Because "first sales" include typical wellhead sales by producers, all natural gas produced from our natural gas properties is sold at market prices, subject to the terms of any private contracts which may be in effect. The FERC's jurisdiction over interstate natural gas transportation is not affected by the Decontrol Act.

Our sales of natural gas will be affected by intrastate and interstate gas transportation regulation. Beginning in 1985, the FERC adopted regulatory changes that have significantly altered the transportation and marketing of natural gas. These changes are intended by the FERC to foster competition by, among other things, transforming the role of interstate pipeline companies from wholesale marketers of natural gas to the primary role of gas transporters. All natural gas marketing by the pipelines is required to divest to a marketing affiliate, which operates separately from the transporter and in direct competition with all other merchants. As a result of the various omnibus rulemaking proceedings in the late 1980s and the subsequent individual pipeline restructuring proceedings of the early to mid-1990s, interstate pipelines must provide open and nondiscriminatory transportation and transportation-related services to all producers, natural gas marketing companies, local distribution companies, industrial end users, and other customers seeking service. Through similar orders affecting intrastate pipelines that provide similar interstate services, the FERC expanded the impact of open access regulations to certain aspects of intrastate commerce.

FERC has pursued other policy initiatives that have affected natural gas marketing. Most notable are (1) the large-scale divestiture of interstate pipeline-owned gas gathering facilities to affiliated or non-affiliated companies; (2) further development of rules governing the relationship of the pipelines with their marketing affiliates; (3) the publication of standards relating to the use of electronic bulletin boards and electronic data exchange by the pipelines to make available transportation information on a timely basis and to enable transactions to occur on a purely electronic basis; (4) further review of the role of the secondary market for released pipeline capacity and its relationship to open access service in the primary market; and (5) development of policy and promulgation of orders pertaining to its authorization of market-based rates (rather than traditional cost-of-service based rates) for transportation or transportation-related services upon the pipeline's demonstration of lack of market control in the relevant service market.

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As a result of these changes, independent sellers and buyers of natural gas have gained direct access to the particular pipeline services they need and are better able to conduct business with a larger number of counter parties. We believe these changes generally have improved the access to markets for natural gas while, at the same time, substantially increasing competition in the natural gas marketplace. However, we cannot predict what new or different regulations the FERC and other regulatory agencies may adopt or what effect subsequent regulations may have on production and marketing of natural gas from our properties.

Although in the past Congress has been very active in the area of natural gas regulation as discussed above, the more recent trend has been in favor of deregulation and the promotion of competition in the natural gas industry. Thus, in addition to “first sales” deregulation, Congress also repealed incremental pricing requirements and natural gas use restraints previously applicable. There continually are legislative proposals pending in the Federal and state legislatures which, if enacted, would significantly affect the petroleum industry. At the present time, it is impossible to predict what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, these proposals might have on the production and marketing of natural gas by us. Similarly, and despite the trend toward federal deregulation of the natural gas industry, whether or to what extent that trend will continue or what the ultimate effect will be on the production and marketing of natural gas by us cannot be predicted.

Our sales of oil and natural gas liquids currently are not regulated and are at market prices. The prices received from the sale of these products are affected by the cost of transporting these products to market. Much of that transportation is through interstate common carrier pipelines. Effective as of January 1, 1995, the FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. These regulations may tend to increase the cost of transporting oil and natural gas liquids by interstate pipeline, although the annual adjustments could result in decreased rates in a given year. These regulations have generally been approved on judicial review. Every five years, the FERC will examine the relationship between the annual change in the applicable index and the actual cost changes experienced by the oil pipeline industry and make any necessary adjustment in the index to be used during the ensuing five years. We are not able to predict with certainty what effect, if any, the periodic review of the index by the FERC will have on us.

Federal, state, and local agencies also have promulgated extensive rules and regulations applicable to our oil and natural gas exploration, production, and related operations. Oklahoma, Texas, and other states require permits for drilling operations, drilling bonds, and the filing of reports concerning operations and impose other requirements relating to the exploration of oil and natural gas. Many states also have statutes or regulations addressing conservation matters including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells, and the regulation of spacing, plugging and, abandonment of such wells. The statutes and regulations of some states limit the rate at which oil and natural gas is produced from our properties. The federal and state regulatory burden on the oil and natural gas industry increases our cost of doing business and affects our profitability. Because these rules and regulations are amended or reinterpreted frequently, we are unable to predict the future cost or impact of complying with those laws.

Our operations are subject to increasingly stringent federal, state, and local laws and regulations governing protection of the environment. These laws and regulations may require acquisition of permits before certain of our operations may be commenced and may restrict the types, quantities, and concentrations of various substances that can be released into the environment. Planning and implementation of protective measures are required to prevent accidental discharges. Spills of oil, natural gas liquids, drilling fluids, and other substances may subject us to penalties and cleanup requirements. Handling, storage, and disposal of both hazardous and non-hazardous wastes are subject to regulatory requirements.

The federal Clean Water Act, as amended by the Oil Pollution Act, the federal Clean Air Act, the federal Resource Conservation and Recovery Act, and their state counterparts, are the primary vehicles for imposition of such requirements and for civil, criminal, and administrative penalties and other sanctions for violation of their requirements. In addition, the federal Comprehensive Environmental Response Compensation and Liability Act and similar state statutes impose strict liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered responsible for the release of hazardous substances into the environment. Such liability, which may be imposed for the conduct of others and for conditions others have caused, includes the cost of remedial action as well as damages to natural resources.

Climate Regulation. Recent scientific studies have suggested that emissions of certain gases, commonly referred to as “greenhouse gases,” or GHGs, may be contributing to warming of the Earth’s atmosphere. As a result there have been a variety of regulatory developments, proposals or requirements, and legislative initiatives that have been introduced in the United States

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(as well as other parts of the World) that are focused on restricting the emission of carbon dioxide, methane, and other greenhouse gases.

In 2007, the United States Supreme Court in Massachusetts, et al. v. EPA, held that carbon dioxide may be regulated as an "air pollutant" under the federal Clean Air Act if it represents a health hazard to the public. On December 7, 2009, the U.S. Environmental Protection Agency ("EPA") responded to the Massachusetts, et al. v. EPA decision and issued a finding that the current and projected concentrations of GHGs in the atmosphere threaten the public health and welfare of current and future generations, and that certain GHGs from new motor vehicles and motor vehicle engines contribute to the atmospheric concentrations of GHG and hence to the threat of climate change. In addition, the EPA issued a final rule, effective in December 2009, requiring the reporting of GHG emissions from specified large (25,000 metric tons or more) GHG emission sources in the U.S., beginning in 2011 for emissions occurring in 2010. During 2010, the EPA proposed revisions to these reporting requirements to apply to all oil and gas production, transmission, processing, and other facilities exceeding certain emission thresholds. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur additional costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the crude oil we gather, transport, store or otherwise handle in connection with our services. In addition, both President Obama and the Administrator of the EPA have repeatedly indicated their preference for comprehensive legislation to address this issue and create the framework for a clean energy economy, with the Obama Administration supporting an emission allowance system. Past proposed legislation in Congress has included an economy wide cap and trade program to reduce U.S. greenhouse gas emissions. Some states are also looking at similar types of laws and regulations.

Our oil and natural gas segment routinely applies hydraulic-fracturing techniques to many of our oil and natural gas properties, including our unconventional resource plays in the Granite Wash of Texas and Oklahoma, the Marmaton of Oklahoma, the Wilcox of Texas, and the Bakken of North Dakota and Montana. The EPA, has commenced a study of the potential environmental impacts of hydraulic fracturing, including the impact on drinking water sources and public health, and a committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. Legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, certain states in which we operate, including Texas and Wyoming have adopted, and other states as well as municipalities and other local governmental entities in some states, have and others are considering adopting regulations and ordinances that could impose more stringent permitting, public disclosure, waste disposal, and well construction requirements on these operations, and possibly even restrict or ban hydraulic fracturing in certain circumstances. Any new laws, regulation, or permitting requirements regarding hydraulic fracturing could lead to operational delay, or increased operating costs or third party or governmental claims, and could result in additional burdens that could serve to delay or limit the drilling services we provide to third parties whose drilling operations could be impacted by these regulations or increase our costs of compliance and doing business as well as delay the development of unconventional gas resources from shale formations which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Further, after reviewing extensive comments and making a number of changes to its previously July 28, 2011 proposed rules, on April 17, 2012 the EPA issued its final rules that subject a wide range of oil and gas operations (production, processing, transmission, storage, and distribution) to regulation under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) programs (with the NSPS and NESHAPS published in the Federal Register on August 16, 2012). The EPA revised the NSPS for volatile organic compounds (VOCs) from leaking components at onshore gas processing plants and the NSPS for sulfur dioxide emissions from natural gas processing plants. The EPA also established standards for certain oil and gas operations not covered by existing standards, which will regulate VOC emissions from gas wells, centrifugal and reciprocating compressors, pneumatic controllers, and storage vessels over a certain size. The EPA also made revisions to the existing leak detection and repair requirements for the oil and gas production source category and the natural gas transmission source category and established action limits reflecting most achievable control for certain previously uncontrolled emission sources. There also are additional testing and related notification, record keeping and reporting requirements. These changes were effective October 15, 2012.

The EPA regulations also result in the first federal air standards for natural gas wells that are hydraulically fractured. Refractured gas wells that use the “green completions” will not be considered affected from a federal standpoint. Operators may choose to flare for now from refractured wells and phase in green completions by January 1, 2015, but any such refractured well will be considered an affected facility for permitting purposes.

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The EPA will be designating nonattainment areas for ozone standards for outdoor quality. These areas will include those areas with significant oil and gas activities. Nonattainment areas will be required to submit state implementation plans in 2015 and to attain the standard by 2015 and 2018 for areas classified as “Marginal” and “Moderate,” respectively. Areas classified as “Serious” must attain by 2021. The federal NSPS constitute a federally required minimum level of control. States have the flexibility to put their own program in place or implement existing programs as long as they are at least as protective as the federal NSPS.

Consequently, while we have been in the process of assessing and implementing the new EPA requirements as required, at this time we do not know and cannot predict with any degree of certainty what areas the EPA will designate nonattainment and what classification will be applied nor what the states may implement for such nonattainment areas which may affect our business segments and use of hydraulic fracturing practices.

We do not know and cannot predict whether there will be any further proposed legislation or regulations It is possible that such future laws, regulations, and/or ordinances could result in increasing our compliance costs or additional operating restrictions as well as those of our customers. It is also possible that such future developments could curtail the demand for fossil fuels which could adversely affect the demand for our services, which in turn could adversely affect our future results of operations. Likewise we cannot predict with any certainty whether any changes to temperature, storm intensity or precipitation patterns as a result of climate change (or otherwise) will have a material impact on our operations.

Compliance with applicable environmental requirements has not, to date, had a material effect on the cost of our operations, earnings, or competitive position. However, as noted above in connection with our discussion of the regulation of GHGs and hydraulic fracturing, compliance with amended, new or more stringent requirements of existing environmental regulations or requirements may cause us to incur additional costs or subject us to liabilities that may have a material adverse effect on our results of operations and financial condition.

FINANCIAL INFORMATION ABOUT GEOGRAPHIC AREAS

Revenues from our Canadian operations during the last three fiscal years, as well as information relating to long-lived assets attributable to those operations are immaterial. We have no other international operations.

Item 1A. Risk Factors

FORWARD-LOOKING STATEMENTS/CAUTIONARY STATEMENT AND RISK FACTORS

This report contains “forward-looking statements” – meaning, statements related to future, not past, events within the meaning of Section 27A of the Securities Act of 1933, as amended and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, included or incorporated by reference in this document which addresses activities, events or developments which we expect or anticipate will or may occur in the future, are forward-looking statements. The words “believes,” “intends,” “expects,” “anticipates,” “projects,” “estimates,” “predicts,” and similar expressions are used to identify forward-looking statements. This report modifies and supersedes documents filed by us before this report. In addition, certain information that we file with the SEC in the future will automatically update and supersede information contained in this report.

These forward-looking statements include, among others, such things as:
- the amount and nature of our future capital expenditures and how we expect to fund our capital expenditures;
- the number of wells we plan to drill or rework;
- prices for oil, NGLs, and natural gas;
- demand for oil, NGLs, and natural gas;

- our exploration and drilling prospects;
- the estimates of our proved oil, NGLs, and natural gas reserves;
- oil, NGLs, and natural gas reserve potential;
- development and infill drilling potential;

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- expansion and other development trends of the oil and natural gas industry;
- our business strategy;
- production of oil, NGLs, and natural gas reserves;
- the number of gathering systems and processing plants we plan to construct or acquire;
- volumes and prices for natural gas gathered and processed and NGLs sold;
- expansion and growth of our business and operations;
- demand and drilling rates for our drilling rigs;
- our belief that the final outcome of our legal proceedings will not materially affect our financial results;
- our ability to timely secure third party services used in completing our wells;
- our ability to transport or convey our oil, NGLs, or natural gas production to established pipeline systems; and
- federal and state legislative and regulatory initiatives relating to hydrocarbon fracturing which could result in increased costs and additional operating restrictions or delays as well as adversely affecting our business.

These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions, and expected future developments as well as other factors we believe are appropriate in the circumstances. However, whether actual results and developments will conform to our expectations and predictions is subject to a number of risks and uncertainties which could cause actual results to differ materially from our expectations, including:

- the risk factors discussed in this report and in the documents we incorporate by reference;
- general economic, market, or business conditions;
- the availability of and nature or lack of business opportunities that we pursue;
- demand for our land drilling services;
- changes in laws or regulations;
- decreases or increases in commodity prices; and
- other factors, most of which are beyond our control.

You should not place undue reliance on any of these forward-looking statements. Except as required by law, we disclaim any current intention to update forward-looking information and to release publicly the results of any future revisions we may make to forward-looking statements to reflect events or circumstances after the date of this report to reflect the occurrence of unanticipated events.

In order to help provide you with a more thorough understanding of the possible effects of some of these influences on any forward-looking statements made by us, the following discussion outlines some (but not all) of the factors that could in the future cause our 2013 and following consolidated results to differ materially from those that may be presented in any forward-looking statement made by us or on our behalf.

Contract Drilling Customer Demand. With the exception of the drilling we do for our own account, the demand for our contract drilling services depends entirely on the needs of third parties. Based on past history, these parties' requirements are subject to a number of factors, independent of any subjective factors that directly impact the demand for our drilling rigs, including the availability of funds to carry out their drilling operations. For many of these parties, even if they have available funds, their decision to spend those funds is often based on the then current price for oil, NGLs, and natural gas. Other factors that affect our ability to work our drilling rigs are: the weather which, under certain circumstances, can delay or even cause the abandonment of a project by an operator; the competition we face in securing the award of drilling contracts; our lack of prior history in and recognition in a new market area; and the availability of labor to operate our drilling rigs.

Oil, NGLs, and Natural Gas Prices. The prices we receive for our oil, NGLs, and natural gas production have a direct impact on our revenues, profitability, and cash flow as well as our ability to meet our projected financial and operational goals.

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The prices for oil, NGLs, and natural gas are determined on a number of factors beyond our control, including:

- the demand for and supply of oil, NGLs, and natural gas;
- current weather conditions in the continental United States (which can greatly influence the demand and prices for natural gas at any given time);
- the amount and timing of liquid natural gas and liquefied petroleum gas imports and exports; and
- the ability of current distribution systems in the United States to effectively meet the demand for oil, NGLs, and natural gas at any given time, particularly in times of peak demand which may result because of adverse weather conditions.

Oil prices are extremely sensitive to foreign influences based on political, social or economic underpinnings, any one of which could have an immediate and significant effect on the price and supply of oil. In addition, prices of oil, NGLs, and natural gas have been at various times influenced by trading on the commodities markets. That trading, at times, has tended to increase the volatility associated with these prices resulting in large differences in prices even on a week-to-week and month-to-month basis. All of these factors, especially when coupled with the fact that much of our product prices are determined on a daily basis, can, and at times do, lead to wide fluctuations in the prices we receive.

Based on our 2012 production, a $0.10 per Mcf change in what we receive for our natural gas production, without the effect of hedging, would result in a corresponding $386,000 per month ($4.6 million annualized) change in our pre-tax operating cash flow. A $1.00 per barrel change in our oil price, without the effect of hedging, would have a $259,000 per month ($3.1 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGLs price, without the effect of hedging, would have a $220,000 per month ($2.6 million annualized) change in our pre-tax operating cash flow.

In order to reduce our exposure to short-term fluctuations in the price of oil, NGLs, and natural gas, we sometimes enter into hedging arrangements such as swaps and collars. To date, we have hedged part, but not all of our production which only provides price protection against declines in oil, NGLs, and natural gas prices on the production subject to our hedges, but not otherwise. Should market prices for the production we have hedged exceed the prices due under our hedges, our hedging arrangements then expose us to risk of financial loss and limit the benefit to us of those increases in market prices. During 2012, substantially all of our oil, NGLs, and natural gas volumes were sold at market responsive prices. To help manage our cash flow and capital expenditure requirements, we hedged approximately 68% and 37% of our 2012 average daily production for oil and natural gas, respectively. A more thorough discussion of our hedging arrangements is contained in the Management’s Discussion and Analysis of Financial Condition and Results of Operations section of this report contained in Item 7.

Uncertainty of Oil, NGLs, and Natural Gas Reserves; Ceiling Test.   There are many uncertainties inherent in estimating quantities of oil, NGLs, and natural gas reserves and their values, including many factors beyond our control. The oil, NGLs, and natural gas reserve information included in this report represents only an estimate of these reserves. Oil, NGLs, and natural gas reservoir engineering is a subjective and an inexact process of estimating underground accumulations of oil, NGLs, and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil, NGLs, and natural gas reserves depend on a number of variable factors, including historical production from the area compared with production from other producing areas, and assumptions concerning:

- reservoir size;
- the effects of regulations by governmental agencies;
- future oil, NGLs, and natural gas prices;
- future operating costs;
- severance and excise taxes;
- development costs; and
- workover and remedial costs.

Some or all of these assumptions may vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil, NGLs, and natural gas attributable to any particular group of properties, classifications of those oil, NGLs, and natural gas reserves based on risk of recovery, and estimates of the future net cash flows

from oil, NGLs, and natural gas reserves prepared by different engineers or by the same engineers but at different times may vary substantially. Accordingly, oil, NGLs, and natural gas reserve estimates may be subject to periodic downward or upward adjustments. Actual production, revenues, and expenditures with respect to our oil, NGLs, and natural gas reserves will likely vary from estimates and those variances may be material.
The information regarding discounted future net cash flows included in this report is not necessarily the current market value of the estimated oil, NGLs, and natural gas reserves attributable to our properties. The use of full cost accounting requires us to use the unweighted arithmetic average of the commodity prices existing on the first day of each of the 12 months before the end of the reporting period to calculate discounted future revenues, unless prices were otherwise determined under contractual arrangements. Actual future prices and costs may be materially higher or lower. Actual future net cash flows are also affected, in part, by the following factors:

- the amount and timing of oil, NGLs, and natural gas production;
- supply and demand for oil, NGLs, and natural gas;
- increases or decreases in consumption; and
- changes in governmental regulations or taxation.

In addition, the 10% discount factor, required by the SEC for use in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and the risks associated with our operations or the oil and natural gas industry in general.

We review quarterly the carrying value of our oil and natural gas properties under the full cost accounting rules of the SEC. Under these rules, capitalized costs of proved oil and natural gas properties may not exceed the present value of estimated future net revenues from those proved reserves, discounted at 10%. Application of this “ceiling test” generally requires pricing future revenue at the unescalated 12-month average price and requires a write-down for accounting purposes if we exceed the ceiling. We may be required to write down the carrying value of our oil and natural gas properties when oil, NGLs, and natural gas prices are depressed. If a write-down is required, it would result in a charge to earnings but would not impact our cash flow from operating activities. Once incurred, a write-down of oil and natural gas properties is not reversible.

As a result of these ceiling test rules, during the quarters ending June 30, 2012 and December 31, 2012, we recorded a non-cash ceiling test write down of $115.9 million pre-tax ($72.1 million, net of tax) and $167.7 million pre-tax ($104.4 million, net of tax), respectively. No ceiling test write down was necessary during 2011 or 2010.
If there are further declines in the 12-month average prices, including the discounted value of our commodity hedges, we may be required to record a write-down in future periods.

We are continually identifying and evaluating opportunities to acquire oil and natural gas properties, including acquisitions that would be significantly larger than those we have consummated to date. We cannot assure you that we will successfully consummate any acquisition, that we will be able to acquire producing oil and natural gas properties that contain economically recoverable reserves or that any acquisition will be profitably integrated into our operations.

Debt and Bank Borrowing. We have incurred and currently expect to continue to incur substantial capital expenditures because of the growth in our operations. Historically, we have funded our capital needs through a combination of internally generated cash flow and borrowings under our bank credit agreement. In 2011 and 2012, we issued $250.0 million (the 2011 Notes) and $400.0 million (the 2012 Notes), respectively, of senior subordinated notes (collectively, the Notes). We have also, from time to time, obtained funds through equity financing. We currently have, and will continue to have, a certain amount of indebtedness. At December 31, 2012, our outstanding long-term debt under our credit agreement was $71.1 million and the amount of the Notes, net of unamortized discount, was $645.3 million.

Depending on the amount of our debt, the cash flow needed to satisfy that debt and the covenants contained in our bank credit agreement and those applicable to the Notes could:

- limit funds otherwise available for financing our capital expenditures, our drilling program or other activities or cause us to curtail these activities;
- limit our flexibility in planning for or reacting to changes in our business;
- place us at a competitive disadvantage to those of our competitors that are less indebted than we are;

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- make us more vulnerable during periods of low oil, NGLs, and natural gas prices or in the event of a downturn in our business; and
- prevent us from obtaining additional financing on acceptable terms or limit amounts available under our existing or any future credit facilities.

Our ability to meet our debt obligations depends on our future performance. If the requirements of our indebtedness are not satisfied, a default could be deemed to occur and our lenders or the holders of the Notes would be entitled to accelerate the payment of the outstanding indebtedness. If that were to occur, we would not have sufficient funds available and probably would not be able to obtain the financing required to meet our obligations.

The amount of our existing debt, as well as our future debt, if any, is, to a large extent, based on the costs associated with the projects we undertake at any given time and of our cash flow. Generally, our normal operating costs are those resulting from the drilling of oil and natural gas wells, the acquisition of producing properties, the costs associated with the maintenance, upgrade or expansion of our drilling rig fleet, and the operations of our natural gas buying, selling, gathering, processing, and treating systems. To some extent, these costs, particularly the first two are discretionary and we maintain a degree of control regarding the timing or the need to incur them. But, in some cases, unforeseen circumstances may arise, such as in the case of an unanticipated opportunity to make a large acquisition or the need to replace a costly drilling rig component due to an unexpected loss, which could force us to incur additional debt above that which we had expected or forecasted. Likewise, if our cash flow should prove to be insufficient to cover our current cash requirements we would need to increase our debt either through bank borrowings or otherwise.

RISK FACTORS

There are many other factors that could adversely affect our business. The following discussion describes the material risks currently known to us. However, additional risks that we do not know about or that we currently view as immaterial may also impair our business or adversely affect the value of our securities. You should carefully consider the risks described below together with the other information contained in, or incorporated by reference into, this report.

If demand for oil, NGLs, and natural gas is reduced, our ability to market as well as produce our oil, NGLs, and natural gas may be negatively affected.

Historically, oil, NGLs, and gas prices have been extremely volatile, with significant increases and significant price drops being experienced from time to time. In the future, various factors beyond our control will have a significant effect on oil, NGLs, and gas prices. Such factors include, among other things, the domestic and foreign supply of oil, NGLs, and gas, the price of foreign imports, the levels of consumer demand, the price and availability of alternative fuels, the availability of pipeline capacity, and changes in existing and proposed federal regulation and price controls.

The oil, NGLs, and natural gas markets are also unsettled due to a number of factors. Production from oil and natural gas wells in some geographic areas of the United States has been curtailed for considerable periods of time due to a lack of market demand and/or transportation and storage capacity. It is possible, however, that some of our wells may in the future be shut-in or that oil, NGLs, and natural gas will be sold on terms less favorable than might otherwise be obtained should demand for oil, NGLs, and natural gas decrease. Competition for available markets has been vigorous and there remains great uncertainty about prices that purchasers will pay. Oil, NGLs, and natural gas surpluses could result in our inability to market oil, NGLs, and natural gas profitably, causing us to curtail production and/or receive lower prices for our oil, NGls, and natural gas, situations which would adversely affect us.

Disruptions in the financial markets could affect our ability to obtain financing or refinance existing indebtedness on reasonable terms and may have other adverse effects.

Commercial-credit market disruptions may result in tight credit markets in the United States. Liquidity in the global-credit markets can be severely contracted by market disruptions making terms for certain financings less attractive, and in certain cases, result in the unavailability of certain types of financing. As a result of credit-market turmoil, we may not be able to obtain debt financing, or refinance existing indebtedness on favorable terms, which could affect operations and financial performance.

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Oil, NGLs, and natural gas prices are volatile, and low prices have negatively affected our financial results and could do so in the future.

Our revenues, operating results, cash flow, and future rate of growth depend substantially on prevailing prices for oil, NGLs, and natural gas. Historically, oil, NGLs, and natural gas prices and markets have been volatile, and they are likely to continue to be volatile in the future. Any decline in prices in the future would have a negative impact on our future financial results.

Prices for oil, NGLs, and natural gas are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil, NGLs, and natural gas, market uncertainty, and a variety of additional factors that are beyond our control. These factors include:

- political conditions in oil producing regions, including the Middle East, Nigeria, and Venezuela;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree on prices and their ability to maintain production quotas;
- the price of foreign oil imports;
- imports of liquefied natural gas;
- actions of governmental authorities;
- the domestic and foreign supply of oil, NGLs, and natural gas;
- the level of consumer demand;
- U.S. storage levels of oil, NGLs, and natural gas;
- weather conditions;
- domestic and foreign government regulations;
- the price, availability, and acceptance of alternative fuels; and
- overall economic conditions.

These factors and the volatile nature of the energy markets make it impossible to predict with any certainty the future prices of oil, NGLs, and natural gas.

Our contract drilling operations depend on levels of activity in the oil, NGLs, and natural gas exploration and production industry.

Our contract drilling operations depend on the level of activity in oil, NGLs, and natural gas exploration and production in our operating markets. Both short-term and long-term trends in oil, NGLs, and natural gas prices affect the level of that activity. Because oil, NGLs, and natural gas prices are volatile, the level of exploration and production activity can also be volatile. Any decrease from current oil, NGLs, and natural gas prices would depress the level of exploration and production activity. This, in turn, would likely result in a decline in the demand for our drilling services and would have an adverse effect on our contract drilling revenues, cash flows, and profitability. As a result, the future demand for our drilling services is uncertain.

The industries in which we operate are highly competitive, and many of our competitors have greater resources than we do.

The drilling industry in which we operate is generally very competitive. Most drilling contracts are awarded on the basis of competitive bids, which may result in intense price competition. Some of our competitors in the contract drilling industry have greater financial and human resources than we do. These resources may enable them to better withstand periods of low drilling rig utilization, to compete more effectively on the basis of price and technology, to build new drilling rigs or acquire existing drilling rigs, and to provide drilling rigs more quickly than we do in periods of high drilling rig utilization.

The oil and natural gas industry is also highly competitive. We compete in the areas of property acquisitions and oil and natural gas exploration, development, production, and marketing with major oil companies, other independent oil and natural gas concerns, and individual producers and operators. In addition, we must compete with major and independent oil and natural gas concerns in recruiting and retaining qualified employees. Many of our competitors in the oil and natural gas industry have substantially greater resources than we do.

Continued growth through acquisitions is not assured.

In the past, we have experienced growth in each of our segments, in part, through mergers and acquisitions. The contract land drilling industry, the exploration and development industry, as well as the gas gathering and processing industry, have experienced significant consolidation over the past several years, and there can be no assurance that acquisition opportunities will continue to be available. Additionally, we are likely to continue to face intense competition from other companies for available acquisition opportunities.

There can be no assurance that we will:

- be able to identify suitable acquisition opportunities;
- have sufficient capital resources to complete additional acquisitions;
- successfully integrate acquired operations and assets;
- effectively manage the growth and increased size;
- maintain the crews and market share to operate any future drilling rigs we may acquire; or
- successfully improve our financial condition, results of operations, business or prospects in any material manner as a result of any completed acquisition.

We may incur substantial indebtedness to finance future acquisitions and also may issue debt instruments, equity securities, or convertible securities in connection with any acquisitions. Debt service requirements could represent a significant burden on our results of operations and financial condition and the issuance of additional equity would be dilutive to existing shareholders. Also, continued growth could strain our management, operations, employees, and other resources.

Successful acquisitions, particularly those of oil and natural gas companies or of oil and natural gas properties require an assessment of a number of factors, many of which are beyond our control. These factors include recoverable reserves, exploration potential, future oil, NGLs, and natural gas prices, operating costs, and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain.

Our operations have significant capital requirements, and our indebtedness could have important consequences.

We have experienced and may continue to experience substantial capital needs in the growth of our operations. We have $645.3 million of indebtedness outstanding (net of unamortized discount) under the senior subordinated notes we have issued to date and in addition, have the right to borrow up to $500.0 million under our credit agreement. As of February 15, 2013, we have outstanding borrowings of $67.5 million under our credit agreement. Our level of indebtedness, the cash flow needed to satisfy our indebtedness, and the covenants governing our indebtedness could:

- limit funds available for financing capital expenditures, our drilling program or other activities or cause us to curtail these activities;
- limit our flexibility in planning for, or reacting to changes in, our business;
- place us at a competitive disadvantage to some of our competitors that are less leveraged than we are;
- make us more vulnerable during periods of low oil, NGLs, and natural gas prices or in the event of a downturn in our business; and
- prevent us from obtaining additional financing on acceptable terms or limit amounts available under our existing or any future credit facilities.

Our ability to meet our debt service and other contractual and contingent obligations will depend on our future performance. In addition, lower oil, NGLs, and natural gas prices could result in future reductions in the amount available for borrowing under our credit agreement, reducing our liquidity, and even triggering mandatory loan repayments.

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The instruments governing our indebtedness contain various covenants limiting the conduct of our business.

The indentures governing our notes and our credit agreement contain various restrictive covenants that limit the conduct of our business. In particular, these agreements will place certain limits on our ability to, among other things:
- incur additional indebtedness, guarantee obligations or issue disqualified capital stock;
- pay dividends or distributions on our capital stock or redeem, repurchase or retire our capital stock;
- make investments or other restricted payments;
- grant liens on assets;
- enter into transactions with stockholders or affiliates;
- sell assets;
- issue or sell capital stock of certain subsidiaries; and
- merge or consolidate.

In addition, our credit agreement also requires us to maintain a minimum current ratio and a maximum leverage ratio. If we fail to comply with the restrictions in the indentures governing our notes, our credit agreement or any other subsequent financing agreements, a default may allow the creditors, if the agreements so provide, to accelerate the related indebtedness as well as any other indebtedness to which a cross-acceleration or cross-default provision applies. If that occurs, we may not be able to make all of the required payments or borrow sufficient funds to refinance that debt. Even if new financing were available at that time, it may not be on terms acceptable to us. In addition, lenders may be able to terminate any commitments they had made to make available further funds.

Our future performance depends on our ability to find or acquire additional oil, NGLs, and natural gas reserves that are economically recoverable.

In general, production from oil and natural gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Unless we successfully replace the reserves that we produce, our reserves will decline, resulting eventually in a decrease in oil, NGLs, and natural gas production and lower revenues and cash flow from operations. Historically, we have succeeded in increasing reserves after taking production into account through exploration and development. We have conducted these activities on our existing oil and natural gas properties as well as on newly acquired properties. We may not be able to continue to replace reserves from these activities at acceptable costs. Lower prices of oil, NGLs, and natural gas may further limit the kinds of reserves that can economically be developed. Lower prices also decrease our cash flow and may cause us to decrease capital expenditures.

We are continually identifying and evaluating opportunities to acquire oil and natural gas properties, including acquisitions that would be significantly larger than those consummated to date by us. We cannot assure you that we will successfully consummate any acquisition, that we will be able to acquire producing oil and natural gas properties that contain economically recoverable reserves or that any acquisition will be profitably integrated into our operations.

The competition for producing oil and natural gas properties is intense. This competition could mean that to acquire properties we will have to pay higher prices and accept greater ownership risks than we have in the past.

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Our exploration and production and mid-stream operations involve a high degree of business and financial risk which could adversely affect us.

Exploration and development involve numerous risks that may result in dry holes, the failure to produce oil, NGLs, and natural gas in commercial quantities and the inability to fully produce discovered reserves. The cost of drilling, completing, and operating wells is substantial and uncertain. Numerous factors beyond our control may cause the curtailment, delay, or cancellation of drilling operations, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- capacity of pipeline systems;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs or delivery crews and the delivery of equipment.

Exploratory drilling is a speculative activity. Although we may disclose our overall drilling success rate, those rates may decline. Although we may discuss drilling prospects that we have identified or budgeted for, we may ultimately not lease or drill these prospects within the expected time frame, or at all. Lack of drilling success will have an adverse effect on our future results of operations and financial condition.

Our mid-stream operations involve numerous risks, both financial and operational. The cost of developing gathering systems and processing plants is substantial and our ability to recoup these costs is uncertain. Our operations may be curtailed, delayed, or canceled as a result of many things beyond our control, including:

- unexpected changes in the deliverability of natural gas reserves from the wells connected to the gathering systems;
- availability of competing pipelines in the area;
- capacity of pipeline systems;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with governmental requirements;
- delays in the development of other producing properties within the gathering system’s area of operation; and
- demand for natural gas and its constituents.

Many of the wells from which we gather and process natural gas are operated by other parties. As a result, we have little control over the operations of those wells which can act to increase our risk. Operators of those wells may act in ways that are not in our best interests.

Competition for experienced technical personnel may negatively impact our operations or financial results.

Our continued oil and natural gas segment and mid-stream segment success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers, and other professionals. Competition for these professionals can be extremely intense, particularly when the industry is experiencing favorable conditions.

Our hedging arrangements might limit the benefit of increases in oil, NGLs, and natural gas prices.

In order to reduce our exposure to short-term fluctuations in the price of oil, NGLs, and natural gas, we sometimes enter into hedging arrangements. Our hedging arrangements apply to only a portion of our production and provide only partial price protection against declines in oil, NGLs, and natural gas prices. These hedging arrangements may expose us to risk of financial

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loss and limit the benefit to us of increases in prices.

Estimates of our reserves are uncertain and may prove to be inaccurate.

There are numerous uncertainties inherent in estimating quantities of proved reserves and their values, including many factors beyond our control. The reserve data represents only estimates. Reservoir engineering is a subjective and inexact process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil, NGLs, and natural gas reserves depend on a number of variable factors, including historical production from the area compared with production from other producing areas, and assumptions concerning:

- the effects of regulations by governmental agencies;
- future oil, NGLs, and natural gas prices;
- future operating costs;
- severance and excise taxes;
- development costs; and
- workover and remedial costs.

Some or all of these assumptions may vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil, NGLs, and natural gas attributable to any particular group of properties, classifications of those reserves based on risk of recovery, and estimates of the future net cash flows from reserves prepared by different engineers or by the same engineers but at different times may vary substantially. Accordingly, reserve estimates may be subject to downward or upward adjustment. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and those variances may be material.

The information regarding discounted future net cash flows should not be considered as the current market value of the estimated oil, NGLs, and natural gas reserves attributable to our properties. As required by the SEC, the estimated discounted future net cash flows from proved reserves are based on prices on the first day of the month for each month within the 12-month period before the end of the reporting period and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by the following factors:

- the amount and timing of actual production;
- supply and demand for oil, NGLs, and natural gas;
- increases or decreases in consumption; and
- changes in governmental regulations or taxation.

In addition, the 10% per year discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our operations or the oil and natural gas industry in general.

If oil, NGLs, and natural gas prices decrease or are unusually volatile, we may be required to take write-downs of our oil and natural gas properties, the carrying value of our drilling rigs or our natural gas gathering and processing systems.

We review quarterly the carrying value of our oil and natural gas properties under the full cost accounting rules of the SEC. Under these rules, capitalized costs of proved oil and natural gas properties may not exceed the present value of estimated future net revenues from proved reserves, discounted at 10% per year. Application of the ceiling test generally requires pricing future revenue at the unweighted arithmetic average of the price on the first day of month for each month within the 12-month period prior to the end of the reporting period, unless prices were defined by contractual arrangements, and requires a write-down for accounting purposes if the ceiling is exceeded. We may be required to write down the carrying value of our oil and natural gas properties when oil, NGLs, and natural gas prices are depressed. If a write-down is required, it would result in a charge to earnings, but would not impact cash flow from operating activities. Once incurred, a write-down of oil and natural gas properties is not reversible at a later date.

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Our drilling equipment, transportation equipment, gas gathering and processing systems, and other property and equipment are carried at cost. We are required to periodically test to see if these values, including associated goodwill and other intangible assets, have been impaired whenever events or changes in circumstances suggest the carrying amount may not be recoverable. If any of these assets are determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. An estimate of fair value is based on the best information available, including prices for similar assets. Changes in these estimates could cause us to reduce the carrying value of property, equipment, and related intangible assets. Once these values have been reduced, they are not reversible.

Our operations present inherent risks of loss that, if not insured or indemnified against, could adversely affect our results of operations.

Our contract drilling operations are subject to many hazards inherent in the drilling industry, including blowouts, cratering, explosions, fires, loss of well control, loss of hole, damaged or lost drilling equipment, and damage or loss from inclement weather. Our exploration and production and mid-stream operations are subject to these and similar risks. Any of these events could result in personal injury or death, damage to or destruction of equipment and facilities, suspension of operations, environmental damage, and damage to the property of others. Generally, drilling contracts provide for the division of responsibilities between a drilling company and its customer, and we seek to obtain indemnification from our drilling customers by contract for some of these risks. To the extent that we are unable to transfer these risks to drilling customers by contract or indemnification agreements (or to the extent we assume obligations of indemnity or assume liability for certain risks under our drilling contracts), we seek protection from some of these risks through insurance. However, some risks are not covered by insurance and we cannot assure you that the insurance we do have or the indemnification agreements we have entered into will adequately protect us against liability from all of the consequences of the hazards described above. The occurrence of an event not fully insured or indemnified against, or the failure of a customer to meet its indemnification obligations, could result in substantial losses. In addition, we cannot assure you that insurance will be available to cover any or all of these risks. Even if available, the insurance might not be adequate to cover all of our losses, or we might decide against obtaining that insurance because of high premiums or other costs.

In addition, we are not the operator of many of our wells. As a result, our operating risks for those wells and our ability to influence the operations for those wells are less subject to our control. Operators of those wells may act in ways that are not in our best interests.

Governmental and environmental regulations could adversely affect our business.

Our business is subject to federal, state, and local laws and regulations on taxation, the exploration for and development, production, and marketing of oil and natural gas, and safety matters. Many laws and regulations require drilling permits and govern the spacing of wells, rates of production, prevention of waste, unitization and pooling of properties, and other matters. These laws and regulations have increased the costs of planning, designing, drilling, installing, operating, and abandoning our oil and natural gas wells and other facilities. In addition, these laws and regulations, and any others that are passed by the jurisdictions where we have production, could limit the total number of wells drilled or the allowable production from successful wells, which could limit our revenues.

We are (or could become) subject to complex environmental laws and regulations adopted by the various jurisdictions where we own or operate. We could incur liability to governments or third parties for discharges of oil, natural gas or other pollutants into the air, soil or water, including responsibility for remedial costs. We could potentially discharge these materials into the environment in any number of ways including the following:

- from a well or drilling equipment at a drill site;

- from gathering systems, pipelines, transportation facilities, and storage tanks;
- damage to oil and natural gas wells resulting from accidents during normal operations; and
- blowouts, cratering, and explosions.

Because the requirements imposed by laws and regulations are frequently changed, we cannot assure you that laws and regulations enacted in the future, including changes to existing laws and regulations, will not adversely affect our business. The current Congress and White House administration may impose or change laws and regulations that will adversely affect our

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business. With the trend toward stricter standards, greater regulation, and more extensive permit requirements, our risks related to environmental matters and our environmental expenditures could increase in the future. In addition, because we acquire interests in properties that have been operated in the past by others, we may be liable for environmental damage caused by the former operators, which liability could be material.

Any future implementation of price controls on oil, NGLs, and natural gas would affect our operations.

Certain groups have asserted efforts to have the United States Congress impose some form of price controls on either oil, natural gas or both. There is no way at this time to know what result these efforts will have nor, if implemented, their effect on our operations. However, it is possible that these efforts, if successful, would serve to limit the amount that we might be able to get for our future oil, NGLs, and natural gas production. Any future limits on the price of oil, NGLs, and natural gas could also result in adversely affecting the demand for our drilling services.

Our shareholders' rights plan and provisions of Delaware law and our by-laws and charter could discourage change in control transactions and prevent shareholders from receiving a premium on their investment.

Our by-laws and charter provide for a classified board of directors with staggered terms and authorizes the board of directors to set the terms of preferred stock. In addition, our charter and Delaware law contain provisions that impose restrictions on business combinations with interested parties. We have also adopted a shareholders' rights plan. Because of our shareholders' rights plan and these provisions of our by-laws, charter, and Delaware law, persons considering unsolicited tender offers or other unilateral takeover proposals may be more likely to negotiate with our board of directors rather than pursue non-negotiated takeover attempts. As a result, these provisions may make it more difficult for our shareholders to benefit from transactions that are opposed by an incumbent board of directors.

New technologies may cause our current exploration and drilling methods to become obsolete, resulting in an adverse effect on our production.

Our industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical, and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. One or more of the technologies that we currently use or that we may implement in the future may become obsolete, and we may be adversely affected.

We may be affected by climate change and market or regulatory responses to climate change.

Climate change, including the impact of potential global warming regulations, could have a material adverse effect on our results of operations, financial condition, and liquidity. Restrictions, caps, taxes, or other controls on emissions of greenhouse gasses, including diesel exhaust, could significantly increase our operating costs. Restrictions on emissions could also affect our customers that (a) use commodities that we carry to produce energy, (b) use significant amounts of energy in producing or delivering the commodities we carry, or (c) manufacture or produce goods that consume significant amounts of energy or burn fossil fuels, including chemical producers, farmers and food producers, and automakers and other manufacturers. Significant cost increases, government regulation, or changes of consumer preferences for goods or services relating to alternative sources of energy or emissions reductions could materially affect the markets for the commodities associated with our business, which in turn could have a material adverse effect on our results of operations, financial condition, and liquidity. Government incentives encouraging the use of alternative sources of energy could also affect certain of our customers and the markets for certain of the commodities associated with our business in an unpredictable manner that could alter our business activities. Finally, we could face increased costs related to defending and resolving legal claims and other litigation related to climate change and the alleged impact of our operations on climate change. Any of these factors, individually or in operation with one or more of the other factors, or other unforeseen impacts of climate change could reduce the amount of business activity we conduct and have a material adverse effect on our results of operations, financial condition, and liquidity.

The results of our operations depend on our ability to transport oil, NGLs, and gas production to key markets.

The marketability of our oil, NGLs, and natural gas production depends in part on the availability, proximity, and capacity of pipeline systems, refineries, and other transportation sources. The unavailability of or lack of available capacity on these

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systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Federal and state regulation of oil, NGLs, and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines, and general economic conditions could adversely affect our ability to produce, gather and, transport oil, NGLs, and natural gas.

The loss of one or a number of our larger customers could have a material adverse effect on our financial condition and results of operations.

During 2012 , QEP Resources, Inc. and Kodiak Oil and Gas Corp. were our largest drilling customers accounting for approximately 15% and 10%, respectively, of our total contract drilling revenues. No other third party customer accounted for 10% or more of our contract drilling revenues. Any of our customers may choose not to use our services and the loss of one or a number of our larger customers could have a material adverse effect on our financial condition and results of operations.

Shortages of completion equipment and services could delay or otherwise adversely affect our oil and natural gas segment's operations.

In the past year or so, the increase in horizontal drilling activity in certain areas has resulted in shortages in the availability of third party equipment and services required for the completion of wells drilled by our oil and natural gas segment. As a result, we have experienced delays in completing some of our wells. Although we have taken steps to try to reduce the delays associated with these services, we anticipate that these services will remain in high demand for the immediate future and could delay, restrict, or curtail part of our exploration and development operations, which could in turn harm our results.

Our mid-stream segment depends on certain natural gas producers and pipeline operators for a significant portion of its supply of natural gas and NGLs. The loss of any of these producers could result in a decline in our volumes and revenues.

We rely on certain natural gas producers for a significant portion of our natural gas and NGLs supply. While some of these producers are subject to long-term contracts, we may be unable to negotiate extensions or replacements of these contracts on favorable terms, if at all. The loss of all or even a portion of the natural gas volumes supplied by these producers, as a result of competition or otherwise, could have a material adverse effect on our mid-stream segment unless we were able to acquire comparable volumes from other sources.

The counterparties to our commodity derivative contracts may not be able to perform their obligations to us, which could materially affect our cash flows and results of operations.

To reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we currently, and may in the future, enter into commodity derivative contracts for a significant portion of our forecasted oil, NGLs, and natural gas production. The extent of our commodity price exposure is related largely to the effectiveness and scope of our derivative activities, as well as to the ability of counterparties under our commodity derivative contracts to satisfy their obligations to us. The worldwide financial and credit crisis may have adversely affected the ability of these counterparties to fulfill their obligations to us. If one or more of our counterparties is unable or unwilling to make required payments to us under our commodity derivative contracts, it could have a material adverse effect on our financial condition and results of operations.

Reliance on management.

We depend greatly on the efforts of our executive officers and other key employees to manage our operations. The loss or unavailability of any of our executive officers or other key employees could have a material adverse effect on our business.

We are subject to various claims and litigation that could ultimately be resolved against us requiring material future cash payments and/or future material charges against our operating income and materially impairing our financial position.

The nature of our business makes us highly susceptible to claims and litigation. We are subject to various existing legal claims and lawsuits, which could have a material adverse effect on our consolidated financial position, results of operations, or cash flows. Any claims or litigation, even if fully indemnified or insured, could negatively affect our reputation among our customers and the public, and make it more difficult for us to compete effectively or obtain adequate insurance in the future.

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Derivatives regulation included in current financial reform legislation could impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices and interest rates.

In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act) was passed by Congress and signed into law. The Act contains significant derivatives regulation, including a requirement that certain transactions be cleared on exchanges and a requirement to post cash collateral (commonly referred to as "margin") for such transactions. The Act provides for a potential exception from these clearing and cash collateral requirements for commercial end-users and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and the parties to those transactions.

We use crude oil, NGLs, and natural gas derivative instruments with respect to a portion of our expected production in order to reduce commodity price uncertainty and enhance the predictability of cash flows relating to the marketing of our crude oil and natural gas. As commodity prices increase, our derivative liability positions increase; however, none of our current derivative contracts require the posting of margin or similar cash collateral when there are changes in the underlying commodity prices that are referred to in these contracts.

Depending on the rules and definitions adopted by the CFTC, we could be required to post collateral with our dealer counterparties for our commodities derivative transactions. Such a requirement could have a significant impact on our business by reducing our ability to execute derivative transactions to reduce commodity price uncertainty and to protect cash flows. Requirements to post collateral would cause significant liquidity issues by reducing our ability to use cash for investment or other corporate purposes, or would require us to increase our level of debt. In addition, a requirement for our counterparties to post collateral would likely result in additional costs being passed on to us, thereby decreasing the effectiveness of our hedges and our profitability.

Proposed federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic-fracturing is an essential and common practice in the oil and gas industry used to stimulate production of oil, natural gas, and associated liquids from dense subsurface rock formations. Our oil and natural gas segment routinely apply hydraulic-fracturing techniques to many of our oil and natural gas properties, including our unconventional resource plays in the Granite Wash of Texas and Oklahoma, the Marmaton of Oklahoma, the Wilcox of Texas, and the Mississippian of Kansas. Hydraulic-fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow the flow of hydrocarbons into the wellbore. The process is typically regulated by state oil and natural gas commissions; however, the EPA has asserted federal regulatory authority over certain hydraulic-fracturing activities involving diesel under the Safe Drinking Water Act and has begun the process of drafting guidance documents related to this newly asserted regulatory authority. In addition, legislation has been introduced before Congress, called the Fracturing Responsibility and Awareness of Chemicals Act, to provide for federal regulation of hydraulic-fracturing and to require disclosure of the chemicals used in the hydraulic-fracturing process.

Certain states in which we operate, including Texas and Wyoming, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, waste disposal, and well construction requirements on hydraulic-fracturing operations or otherwise seek to ban fracturing activities altogether. For example, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas (RCT) and the public of certain information regarding the components used in the hydraulic-fracturing process. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling and/or completion of wells.

There are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic-fracturing practices. The White House Council on Environmental Quality is coordinating a review of hydraulic-fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic-fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. In addition, the U.S. Department of Energy is

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conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods.

Additionally, certain members of the Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the U.S. Securities and Exchange Commission to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. These ongoing or proposed studies, depending on their course and results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory processes.

Further, after reviewing extensive comments and making a number of changes to its previously July 28, 2011 proposed rules, on April 17, 2012 the EPA issued its final rules that subject a wide range of oil and gas operations (production, processing, transmission, storage, and distribution) to regulation under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) programs (with the NSPS and NESHAPS published in the Federal Register on August 16, 2012). The EPA revised the NSPS for volatile organic compounds (VOCs) from leaking components at onshore gas processing plants and the NSPS for sulfur dioxide emissions from natural gas processing plants. The EPA also established standards for certain oil and gas operations not covered by existing standards, which will regulate VOC emissions from gas wells, centrifugal and reciprocating compressors, pneumatic controllers, and storage vessels over a certain size. The EPA also made revisions to the existing leak detection and repair requirements for the oil and gas production source category and the natural gas transmission source category and established action limits reflecting most achievable control for certain previously uncontrolled emission sources. There also are additional testing and related notification, record keeping and reporting requirements. These changes were effective October 15, 2012.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil, natural gas, and associated liquids including from the development of shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of additional federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells, increased compliance costs and time, which could adversely affect our financial position, results of operations, and cash flows.

On October 20, 2011, EPA announced a schedule for development of standards for disposal of wastewater produced from shale gas operations to publicly owned treatment works (POTWs). The regulations will be developed under EPA's Effluent Guidelines Program under the authority of the Clean Water Act. EPA anticipates issuing the proposed rules in 2014.

Our ability to produce crude oil, natural gas, and associated liquids economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling operations and/or completions or are unable to dispose of or recycle the water we use at a reasonable cost and in accordance with applicable environmental rules.

To our knowledge, there have been no citations, suits, or contamination of potable drinking water arising from our fracturing operations. We do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations; however, it is possible that our general liability and excess liability insurance policies might cover third-party claims related to hydraulic fracturing operations and associated legal expenses depending on the specific nature of the claims, the timing of the claims, as well as the specific terms of such policies.

The hydraulic fracturing process on which we depend to produce commercial quantities of crude oil, natural gas, and associated liquids from many reservoirs requires the use and disposal of significant quantities of water.

Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our oil and natural gas segment operations, could adversely impact our operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of wastes, including, but not limited to, produced water, drilling fluids, and other wastes associated with the exploration, development or production of oil and natural gas.

Compliance with environmental regulations and permit requirements governing the withdrawal, storage and, use of

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surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions, or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial condition.

Events in the financial markets and the economy could adversely affect our operations and financial condition.
As a result of volatility in oil, NGLs, and natural gas prices and substantial uncertainty in the capital markets due to the uncertain global economic environment, a number of our drilling customers have reduced spending on exploration and development drilling. In addition, it is uncertain whether customers, vendors, and/or suppliers will be able to access financing necessary to sustain their operations, fulfill their commitments, or fund future operations and obligations. The uncertainty in the global economic environment may result in a decrease in demand for drilling rigs. These conditions could have a material adverse effect on our business, financial condition, and results of operations.
We may decide not to drill some of the prospects we have identified, and locations that we do drill may not yield oil, natural gas, and NGLs in commercially viable quantities.
Our oil and natural gas segment's prospective drilling locations are in various stages of evaluation, ranging from a prospect that is ready to drill to a prospect that will require additional geological and engineering analysis. Based on a variety of factors, including future oil, natural gas, and NGLs prices, the generation of additional seismic or geological information, and other factors, we may decide not to drill one or more of these prospects. As a result, we may not be able to increase or maintain our reserves or production, which in turn could have an adverse effect on our business, financial position, and results of operations. In addition, the SEC's reserve reporting rules include a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. At December 31, 2012, we had 151 proved undeveloped drilling locations. To the extent that we do not drill these locations within five years of initial booking, they may not continue to qualify for classification as proved reserves, and we may be required to reclassify such reserves as unproved reserves. The reclassification of those reserves could also have a negative effect on the borrowing base under our credit facility.

The cost of drilling, completing, and operating a well is often uncertain, and cost factors can adversely affect the economics of a well. Our efforts will be uneconomic if we drill dry holes or wells that are productive but do not produce enough oil, NGLs, and natural gas to be commercially viable after drilling, operating, and other costs.
The borrowing base under our credit agreement is determined semi-annually at the discretion of the lenders and is based in a large part on the prices for oil, NGLs, and natural gas.

Significant declines in oil, NGLs, and natural gas prices may result in a decrease in our borrowing base. The lenders can unilaterally adjust the borrowing base and therefore the borrowings permitted to be outstanding under our credit agreement. If outstanding borrowings are in excess of the borrowing base, we must (a) repay the loan in excess of the borrowing base, (b) dedicate additional properties to the borrowing base, or (c) begin monthly principal payments in accordance with our credit agreement.

Item 1B. Unresolved Staff Comments
None.

Item 2. Properties
The information called for by this item was consolidated with and disclosed in connection with Item 1 above.

Item 3. Legal Proceedings
Panola Independent School District No. 4, et al. v. Unit Petroleum Company, No. CJ-07-215, District Court of Latimer County, Oklahoma.

Panola Independent School District No. 4, Michael Kilpatrick, Gwen Grego, Carla Lessel, Thelma Christine Pate, Juanita Golightly, Melody Culberson and Charlotte Abernathy are the Plaintiffs in this case and are royalty owners in oil and gas drilling and spacing units for which the our exploration segment distributes royalty. The Plaintiffs' central allegation is that our exploration segment has underpaid royalty obligations by deducting post-production costs or marketing related fees. Plaintiffs sought to pursue the case as a class action on behalf of persons who receive royalty from us for our Oklahoma production. We

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have asserted several defenses including that the deductions are permitted under Oklahoma law. We also asserted that the case should not be tried as a class action due to the materially different circumstances that determine what, if any, deductions are taken for each lease. On December 16, 2009, the trial court entered its order certifying the class. On May 11, 2012, the Court of Civil Appeals reversed the trial court's order certifying the class. The Plaintiffs petitioned the Oklahoma Supreme Court for certiorari and on October 8, 2012, the Plaintiff's petition was denied. The Plaintiffs recently filed a second request to certify a class of royalty owners that is slightly smaller than their first attempt. We will continue to resist certification using the defenses described above, as well as new defenses based on the Court of Civil Appeals' decertification of the Plaintiffs' original class action. The merits of Plaintiffs' claims will remain stayed while class certification issues are pending.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for the Registrant’s Common Equity, Related Stockholder Matters, and Issuer Purchases of Equity Securities

Our common stock trades on the New York Stock Exchange under the symbol “UNT.” The following table identifies the high and low sales prices per share of our common stock for the periods indicated:

	2012		2011	
Quarter	High	Low	High	Low
First	$50.82	$41.53	$62.47	$44.84
Second	$43.83	$32.14	$63.76	$51.58
Third	$46.27	$34.59	$62.66	$36.50
Fourth	$46.97	$39.73	$53.35	$33.58

On February 15, 2013, the closing sale price of our common stock, as reported by the NYSE, was $48.24 per share. On that date, there were approximately 1,064 holders of record of our common stock.

We have never declared any cash dividends on our common stock and currently have no plans to do so. Any future determination by our board of directors to pay dividends on our common stock will be made only after considering our financial condition, results of operations, capital requirements and other relevant factors. Additionally, our bank credit agreement and the Notes prohibit the payment of cash dividends on our common stock under certain circumstances. For further information regarding our bank credit agreement and the Notes agreement’s impact on our ability to pay dividends see “Our Credit Agreement and Senior Subordinated Notes” under Item 7 of this report.

Performance Graph. The following graph and related information shall not be deemed “soliciting material” or be deemed to be “filed” with the SEC, nor shall such information be incorporated by reference into any future filing, except to the extent that we specifically incorporate it by reference into such filing.

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Set forth below is a line graph comparing our cumulative total shareholder return on our common stock with the cumulative total return of the S&P 500 Stock Index, S&P 600 Oil and Gas Exploration & Production and our peer group which includes Helmerich & Payne, Patterson – UTI Energy Inc. and Pioneer Drilling Co. The graph below assumes an investment of $100 at the beginning of the period. The shareholder return set forth below is not necessarily indicative of future performance.

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Item 6. Selected Financial Data

The following table shows selected consolidated financial data. The data should be read in conjunction with Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations," for a review of 2012, 2011, and 2010 activity.

	As of and for the Year Ended December 31,				
	2012	2011	2010	2009	2008
	(In thousands except per share amounts)				
Revenues[1]	$1,315,123	$1,207,503	$870,671	$707,188	$1,357,153
Net income (loss)	$23,176 [2]	$195,867	$146,484	$(55,500) [3]	$143,625 [4]
Net income (loss) per common share:					
Basic	$0.48	$4.11	$3.10	$(1.18)	$3.08
Diluted	$0.48	$4.08	$3.09	$(1.18)	$3.06
Total assets	$3,761,120	$3,256,720	$2,669,240	$2,228,399	$2,581,866
Long-term debt	$716,359	$300,000	$163,000	$30,000	$199,500
Other long-term liabilities	$167,545	$113,830	$92,389	$81,126	$75,807
Cash dividends per common share	$—	$—	$—	$—	$—

(1) During the third quarter of 2012, we made the decision to prospectively use mark-to-market accounting for our economic hedges. Previously, we reported all realized and unrealized hedging gains (losses) in oil and natural gas revenues and now we reflect gains (losses) on non-designated hedges and the ineffectiveness from cash flow hedges along with other revenue items in other income (expense) below income from operations. Prior year amounts have been reclassified to conform to current year presentation.

(2) In June 2012 and December 2012, due to low 12-month average commodity prices, we incurred non-cash ceiling test write downs of our oil and natural gas properties of $115.9 million pre-tax ($72.1 million net of tax) and $167.7 million pre-tax ($104.4 million net of tax), respectively.

(3) In March 2009, we incurred a non-cash ceiling test write down of our oil and natural gas properties of $281.2 million pre-tax ($175.1 million net of tax) due to low commodity prices at quarter-end.

(4) In December 2008, we incurred a non-cash ceiling test write down of our oil and natural gas properties of $282.0 million pre-tax ($175.5 million net of tax) due to low commodity prices at year-end.

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Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Please read the following discussion of our financial condition and results of operations in conjunction with the consolidated financial statements and related notes included in Item 8 of this report.

General

We operate, manage, and analyze our results of operations through our three principal business segments:

- Contract Drilling – carried out by our subsidiary Unit Drilling Company and its subsidiaries. This segment contracts to drill onshore oil and natural gas wells for others and for our own account.
- Oil and Natural Gas – carried out by our subsidiary Unit Petroleum Company. This segment explores, develops, acquires, and produces oil and natural gas properties for our own account.
- Mid-Stream – carried out by our subsidiary Superior Pipeline Company, L.L.C. and its subsidiaries. This segment buys, sells, gathers, processes, and treats natural gas for third parties and for our own account.

Business Outlook

As discussed in other parts of this report, the success of our consolidated business, as well as that of each of our three operating segments depends, to a large extent, on: the prices we receive for our oil, NGLs, and natural gas production; the demand for oil, NGLs, and natural gas; and the demand for our drilling rigs which, in turn, influences the amounts we can charge for the use of those drilling rigs. Although all of our current operations (with the exception of a minor amount of production in Canada) are located within the United States, events outside the United States can and do have an impact on us and our industry.

In addition to their direct impact on us, low commodity prices–if sustained for a long period of time–could impact the liquidity of some of our industry partners and customers which, in turn, could limit their ability to meet their financial obligations to us.

Our 2013 current capital budget for all of our business segments forecasts a 6% increase over our 2012 capital expenditures, excluding acquisitions. Our oil and natural gas segment's capital budget is $586.0 million, a 16% increase over 2012, excluding acquisitions and ARO liability. We plan to continue our aggressive drilling program into 2013 with a significant portion of the wells being horizontal. Our drilling segment's capital budget is $98.0 million, a 26% increase over 2012. Our plans for 2013 include continuing to refurbish and upgrade several of our existing drilling rigs in order that those drilling rigs can be used in horizontal drilling operations. Our mid-stream segment's capital budget is $105.0 million, a 36% decrease from 2012, excluding acquisitions. New and continued projects are discussed further in the Executive Summary.

Our 2013 current capital expenditures budget is based on realized prices for the year of $93.05 per barrel of oil, $32.05 per barrel of NGLs, and $3.56 per Mcf. This budget is subject to possible periodic adjustments for various reasons including changes in commodity prices and industry conditions. Funding for the budget will come primarily from internally generated cash flow and, if necessary, borrowings under our credit agreement.

Executive Summary

Contract Drilling

The rate at which our drilling rigs were used ("our utilization rate") for the fourth quarter 2012 was 50%, compared to 58% and 65% for the third quarter of 2012 and the fourth quarter of 2011, respectively.

Dayrates for the fourth quarter of 2012 averaged $19,828, a 1% decrease from the third quarter of 2012 and an increase of 3% over the fourth quarter of 2011. The decrease from the third quarter of 2012 is due primarily to the terminated contracts having higher rates (drilling rigs that were under long-term contracts, but were terminated early by the operator). The increase over the fourth quarter of 2011 was due primarily to new drilling rigs going into service for which we received a higher rate, increased demand for drilling rigs in the 1,000 horsepower range which increased their rates somewhat offset by the decrease in higher dayrates associated with the terminated contracts.

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Direct profit (contract drilling revenue less contract drilling operating expense) for the fourth quarter of 2012 decreased 29% from the third quarter of 2012 and 32% from the fourth quarter of 2011. For both comparative periods utilization decreased. Additionally, during the fourth quarter of 2012, we received $0.1 million in termination fees compared to $6.7 million received in the third quarter of 2012 for three drilling rigs that were under long-term contracts but were terminated early by the operator.

Operating cost per day for the fourth quarter of 2012 increased 3% over the third quarter of 2012 and 6% over the fourth quarter of 2011. The increases over the third quarter were primarily due to increases in drilling rig servicing and workers' compensation costs while the increases over the fourth quarter of 2011 are primarily due to increases in direct expenses due to wage increases for rig personnel and to a lesser extent from higher worker's compensation and indirect costs.

Historically, our contract drilling segment has experienced a greater demand for natural gas drilling as opposed to drilling for oil and NGLs. However, with the current weakened natural gas market, operators are now focusing on drilling for oil and NGLs. Today, approximately 99% of our working drilling rigs are drilling for oil or NGLs. Of those, approximately 97% are drilling horizontal or directional wells.

During 2011, we were awarded two additional new build rig contracts for 1,500 horsepower, diesel-electric drilling rigs. One was placed into service during the fourth quarter of 2011 and the other was placed in service during the first quarter of 2012, both in Wyoming.
During the first quarter of 2012, we sold an idle 600 horsepower mechanical drilling rig to an unaffiliated third-party. Additionally, during the second quarter of 2012, we placed another new 1,500 horsepower, diesel-electric drilling rig in North Dakota (under a three year contract).
During the third quarter of 2012, we had a fire on one of our drilling rigs in the mid-continent region. The net book value of the damaged equipment on the rig was $3.2 million. We expect that all of the net book value of the damaged equipment will be recoverable from insurance proceeds. As a result of this loss, this segment now has 127 drilling rigs in its fleet. No personnel were injured in this incident.

Our anticipated 2013 capital expenditures for this segment are $98.0 million, a 26% increase over 2012.

As of December 31, 2012, we had 27 term drilling contracts with original terms ranging from six months to three years. Twenty-one of these contracts are up for renewal in 2013, six in the first quarter, five in the second quarter, eight in the third quarter and two in the fourth quarter and six are up for renewal in 2014 and later. Term contracts may contain a fixed rate for the duration of the contract or provide for rate adjustments within a specific range from the existing rate.

Oil and Natural Gas

Fourth quarter 2012 production from our oil and natural gas segment was 4,115,000 barrels of oil equivalent (Boe), an 18% increase over the third quarter of 2012 and a 26% increase over the fourth quarter of 2011. These increases came primarily from production associated with the Noble acquisition and, to a lesser extent, from new wells completed in oil and NGLs rich prospects. Oil and NGLs production during 2012 was 43% of our total production compared to 39% of our total production during 2011.

Fourth quarter 2012 oil and natural gas revenues increased 22% over the third quarter of 2012 and increased 17% over the fourth quarter of 2011. These increases were primarily due to increases in production and commodity prices.

Our NGLs, natural gas, and oil prices for the fourth quarter of 2012 increased 59%, 7%, and 1%, respectively, over the third quarter of 2012. Our oil prices increased 4% over the fourth quarter of 2011 while natural gas and NGLs prices decreased 11% and 22%, respectively.

Direct profit (oil and natural gas revenues less oil and natural gas operating expense) increased 21% over the third quarter of 2012 and 16% over the fourth quarter of 2011. The increases were primarily attributable to increased production from developmental drilling and acquisitions, as well as increases in commodity prices over the third quarter of 2012.

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Operating cost per Boe produced for the fourth quarter of 2012 increased 6% over the third quarter of 2012 and decreased 5% from the fourth quarter of 2011. The costs increased over the third quarter of 2012 due to increased gross production taxes and increases in lease operating expenses (LOE) due to increased workover expense and higher saltwater disposal fees. The decrease from the fourth quarter 2011 was primarily due to a decrease in well servicing and transportation charges and a decrease in production taxes due to tax credits applied to the 2012 rate.

For the quarter ended June 30, 2012, the 12-month average commodity prices, including the discounted value of our cash flow hedges, decreased significantly resulting in a non-cash ceiling test write down of $115.9 million pre-tax ($72.1 million, net of tax). Our qualifying cash flow hedges used in the ceiling test determination at June 30, 2012, consisted of swaps and collars, covering production of 0.0 MMBoe in 2012 and 0.0 MMBoe in 2013. The effect of those hedges on the June 30, 2012 ceiling test was a $32.5 million pre-tax increase in the discounted net cash flows of our oil and natural gas properties.

For the quarter ended December 31, 2012, the 12-month average commodity prices, including the discounted value of our cash flow hedges, decreased significantly resulting in a non-cash ceiling test write down of $167.7 million pre-tax ($104.4 million, net of tax). Our qualifying cash flow hedges used in the ceiling test determination at December 31, 2012, consisted of swaps and collars covering 0.0 MMBoe in 2013. The effect of those hedges on the December 31, 2012 ceiling test was a $29.8 million pre-tax increase in the discounted net cash flows of our oil and natural gas properties. Our oil and natural gas hedging is discussed in Note 13 of the Notes to our Consolidated Financial Statements.

If there are further declines in the 12-month average prices, including the discounted value of our commodity hedges, we may be required to record a write-down in future periods.

For 2012 we hedged approximately 68% of our average daily oil production and approximately 37% of our average natural gas production to help manage our cash flow and capital expenditure requirements.

Currently for 2013 we have hedged approximately 8,330 Bbls per day of oil production and 100,000 Mmbtu per day of natural gas production. The oil production is hedged under swap contracts at an average price of $97.94 per barrel. The natural gas production is hedged by swaps for 80,000 Mmbtu per day and a collar for 20,000 Mmbtu per day. The swap transactions were done at a comparable average NYMEX price of $3.65. The collar transaction was done at a comparable average NYMEX floor price of $3.25 and ceiling price of $3.72.

Currently for 2014 we have hedged 4,000 Bbls per day of oil production. The oil production is hedged by swaps for 2,000 Bbls per day and collars for 2,000 Bbls per day. The swap transactions were done at an average price of $91.40 per barrel. The collar transactions were done at an average floor price of $90.00 per barrel and ceiling price of $95.00 per barrel.

On September 17, 2012, we closed on the acquisition of certain oil and natural gas assets from Noble. After final closing adjustments, the acquisition included approximately 83,000 net acres primarily in the Granite Wash, Cleveland, and various other plays in western Oklahoma and the Texas Panhandle. The adjusted amount paid was $592.6 million.

As of April 1, 2012, the effective date of the Noble acquisition, the estimated proved reserves of the acquired properties were 44 MMBoe, The acquisition added approximately 24,000 net leasehold acres to our Granite Wash core area in the Texas Panhandle with significant potential including approximately 600 possible future horizontal drilling locations. The total acreage acquired in other plays in western Oklahoma and the Texas Panhandle was approximately 59,000 net acres and was characterized by high working interest and operatorship, 95% of which was held by production. We also received four gathering systems as part of the transaction and other miscellaneous assets.

Also in September 2012, we sold our interest in certain Bakken properties (representing approximately 35% of our total acreage in the Bakken play). The proceeds, net of related expenses were $226.6 million. In addition, we sold certain oil and natural gas assets located in Brazos and Madison Counties, Texas for approximately $44.1 million. Both dispositions were accounted for as adjustments to the full cost pool with no gain or loss recognized.

During 2012, we drilled 171 wells (80.08 net wells). Our 2013 production guidance is approximately 16.0 to 16.5 MMBoe, an increase of 13% to 16% over 2012, although actual results will continue to be subject to many factors. For 2013, we plan to participate in the drilling of 180 wells. Our oil and natural gas segment's capital budget is $586.0 million, a 16% increase over 2012, excluding acquisitions and ARO liability.

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Mid-Stream

Fourth quarter 2012 liquids sold per day decreased 23% from the third quarter of 2012 and decreased 14% from the fourth quarter of 2011. During the third quarter 2012, one of our customers completed construction of their own processing plant and moved their volumes off our system resulting in decreases in liquids sold, gas gathered, and gas processed. In addition, during the fourth quarter of 2012, certain processing plants were rejecting ethane due to weak ethane prices. For the fourth quarter of 2012, gas processed per day decreased 2% from the third quarter of 2012 and increased 4% over the fourth quarter of 2011. In 2011 and 2012, we upgraded several of our existing processing facilities and added processing plants which was the primary reason for increased volumes. In 2012, these increases were offset by the decrease of one of our customers discussed above. For the fourth quarter of 2012, gas gathered per day increased 17% over the third quarter of 2012 and increased 26% over the fourth quarter of 2011 primarily from well connects throughout 2012.

NGLs prices in the fourth quarter of 2012 increased 31% over the prices received in the third quarter of 2012 and decreased 11% from the prices received in the fourth quarter of 2011. Because certain of the contracts used by our mid-stream segment for NGLs transactions are percent of proceeds (POP) contracts -- under which we receive a share of the proceeds from the sale of the NGLs--our revenues from those POP contracts fluctuate based on the prices of NGLs.

Direct profit (mid-stream revenues less mid-stream operating expense) for the fourth quarter of 2012 decreased 4% from the third quarter of 2012 and decreased 16% from the fourth quarter of 2011. The decreases were primarily due to decreases in NGLs volumes from the comparative periods. This was slightly offset by an increase in NGLs prices from the third quarter of 2012. Total operating cost for our mid-stream segment for the fourth quarter of 2012 increased 10% over the third quarter of 2012 and decreased 8% from the fourth quarter of 2011 due primarily to the increase and decrease in gas purchased in the respective period.

During the second quarter of 2012, we completed the installation of our fifth processing plant at our Hemphill County, Texas facility. We now have the capacity at that facility to process 160 MMcf per day of our own and third-party Granite Wash natural gas production.

At our Cashion facility, we have extended our gathering system to the north to connect wells that are being drilled in that area. Due to this increased activity, we installed a new 25 MMcf per day high efficiency turbo-expander processing plant at this facility that became operational in March 2012. With the installation of this additional plant, our total processing capacity increased to approximately 45 MMcf per day at our Cashion facility.

In the Mississippian play in north central Oklahoma, a new gas gathering system and processing plant in Noble and Kay Counties, Oklahoma, known as the Bellmon system, was completed and began operating late in the second quarter. This system currently consists of approximately 83 miles of pipelines with a 20 MMcf per day gas processing plant. An additional 30 MMcf per day gas processing plant is scheduled to be installed in the first quarter of 2013. We also connected our existing Remington system to the new Bellmon system which required laying approximately 26 miles of pipeline and installing related compression services. In addition to these projects, we completed the installation of a NGLs line from our Bellmon plant to Medford, Oklahoma. This project consists of approximately 20 miles of 6” pipeline and was completed in the 4th quarter of 2012.

We are continuing to expand operations in the Appalachian region. In the fourth quarter of 2012, construction was completed on the first phase of our Pittsburgh Mills gathering facility in Allegheny and Butler Counties, Pennsylvania. The first phase of this project consists of approximately seven miles of gathering pipeline. In the first quarter of 2013, the related compressor station will be completed. We currently have 10 wells connected to this gathering system. The current gathered volumes from these wells is approximately 28 MMcf per day. Construction activity for expansion of this pipeline continues as the producer is maintaining its drilling activity.

In December 2012, we had a $1.2 million write-down of our Erick system. There was no volume from the wells connected to this system, the compressor and related surface equipment have been removed from this location and there is no future activity anticipated from this gathering system.

Our anticipated 2013 capital expenditures for this segment are $105.0 million, a 36% decrease from 2012, excluding acquisitions.

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Critical Accounting Policies and Estimates

Summary

In this section, we identify those critical accounting policies we follow in preparing our financial statements and related disclosures. Many of these policies require us to make difficult, subjective, and complex judgments in the course of making estimates of matters that are inherently imprecise. Some accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. In the following discussion we will attempt to explain the nature of these estimates, assumptions and judgments, as well as the likelihood that materially different amounts would be reported in our financial statements under different conditions or using different assumptions.

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The following table lists the critical accounting policies, estimates and assumptions that can have a significant impact on the application of these accounting policies, and the financial statement accounts affected by these estimates and assumptions.

Accounting Policies	Estimates or Assumptions	Accounts Affected
Full cost method of accounting for oil, NGLs, and natural gas properties	• Oil, NGLs, and natural gas reserves, estimates and related present value of future net revenues • Valuation of unproved properties • Estimates of future development costs • Derivatives measured at fair value	• Oil and natural gas properties • Accumulated depletion, depreciation and amortization • Provision for depletion, depreciation and amortization • Impairment of oil and natural gas properties • Long-term debt and interest expense
Accounting for ARO for oil, NGLs, and natural gas properties	• Cost estimates related to the plugging and abandonment of wells • Timing of cost incurred	• Oil and natural gas properties • Accumulated depletion, depreciation and amortization • Provision for depletion, depreciation and amortization • Current and non-current liabilities • Operating expense
Accounting for impairment of long-lived assets	• Forecast of undiscounted estimated future net operating cash flows	• Drilling and mid-stream property and equipment • Accumulated depletion, depreciation and amortization • Provision for depletion, depreciation and amortization • Other intangible assets
Goodwill	• Forecast of discounted estimated future net operating cash flows • Terminal value • Weighted average cost of capital	• Goodwill
Turnkey and footage drilling contracts	• Estimates of costs to complete turnkey and footage contracts	• Revenue and operating expense • Current assets and liabilities
Accounting for value of stock compensation awards	• Estimates of stock volatility • Estimates of expected life of awards granted • Estimates of rates of forfeitures	• Oil and natural gas properties • Shareholder's equity • Operating expenses • General and administrative expenses
Accounting for derivative instruments and hedging	• Hedges measured for effectiveness and ineffectiveness • Non-qualifying and qualifying derivatives measured at fair value	• Current and non-current derivative assets and liabilities • Other comprehensive income as a component of equity

- Oil and natural gas revenue
- Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net

Significant Estimates and Assumptions

Full Cost Method of Accounting for Oil, NGLs, and Natural Gas Properties. The determination of our oil, NGLs, and natural gas reserves is a subjective process. It entails estimating underground accumulations of oil, NGLs, and natural gas that cannot be measured in an exact manner. The degree of accuracy of these estimates depends on a number of factors, including,

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the quality and availability of geological and engineering data, the precision of the interpretations of that data, and individual judgments. Each year, we hire an independent petroleum engineering firm to audit our internal evaluation of our reserves. The wells or locations for which estimates of reserves were audited were those that comprised the top 82% of the total proved developed discounted future net income and 87% of the total proved undeveloped discounted future net income based on the unescalated pricing policy of the SEC as taken from reserve and income projections prepared by us as of December 31, 2012. Included in Part I, Item 1 of this report are the qualifications of our independent petroleum engineering firm and our personnel responsible for the preparation of our reserve reports.

As a general rule, the degree of accuracy of oil, NGLs, and natural gas reserve estimates varies with the reserve classification and the related accumulation of available data, as shown in the following table:

Type of Reserves	Nature of Available Data	Degree of Accuracy
Proved undeveloped	Data from offsetting wells, seismic data	Less accurate
Proved developed non-producing	The above as well as logs, core samples, well tests, pressure data	More accurate
Proved developed producing	The above as well as production history, pressure data over time	Most accurate

Assumptions as to future oil, NGLs, and natural gas prices and operating and capital costs also play a significant role in estimating oil, NGLs, and natural gas reserves and the estimated present value of the cash flows to be received from the future production of those reserves. Volumes of recoverable reserves are influenced by the assumed prices and costs due to what is known as the economic limit (that point in the future when the projected costs and expenses of producing recoverable oil, NGLs, and natural gas reserves is greater than the projected revenues from the oil, NGLs, and natural gas reserves). But more significantly, the estimated present value of the future cash flows from our oil, NGLs, and natural gas reserves is extremely sensitive to prices and costs, and may vary materially based on different assumptions. Companies using full cost accounting use the unweighted arithmetic average of the commodity prices existing on the first day of each of the 12 months before the end of the reporting period to calculate discounted future revenues, unless prices were otherwise determined under contractual arrangements.

We compute our provision for DD&A on a units-of-production method. Each quarter, we use the following formulas to compute the provision for DD&A for our producing properties:
- DD&A Rate = Unamortized Cost / End of Period Reserves Adjusted for Current Period Production
- Provision for DD&A = DD&A Rate x Current Period Production

Oil, NGLs, and natural gas reserve estimates have a significant impact on our DD&A rate. If reserve estimates for a property or group of properties are revised downward in the future, the DD&A rate will increase as a result of the revision. Alternatively, if reserve estimates are revised upward, the DD&A rate will decrease. Based on our 2012 production level of 14.2 MMBoe, a 5% decline in the amount of our 2012 oil, NGLs, and natural gas reserves would increase our DD&A rate by $0.72 per Boe and would decrease pre-tax income by $10.2 million annually. A 5% increase in the amount of our 2012 oil, NGLs, and natural gas reserves would decrease our DD&A rate by $0.60 per Boe and would increase pre-tax income by $8.5 million annually.

Our DD&A expense on our oil and natural gas properties is calculated each quarter using period end reserve quantities adjusted for current period production.

We account for our oil and natural gas exploration and development activities using the full cost method of accounting. Under this method, all costs incurred in the acquisition, exploration, and development of oil and natural gas properties are capitalized. At the end of each quarter, the net capitalized costs of our oil and natural gas properties are limited to the lower of unamortized cost or a ceiling. The ceiling is defined as the sum of the present value (using a 10% discount rate) of the estimated future net revenues from our proved reserves based on the unescalated 12-month average price on our oil, NGLs, and natural gas adjusted for any cash flow hedges, plus the cost of properties not being amortized, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, less related income taxes. If the net capitalized costs of our oil and natural gas properties exceed the ceiling, we are required to write-down the excess amount. A ceiling test write-down is

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a non-cash charge to earnings. If required, it reduces earnings and impacts shareholders' equity in the period of occurrence and results in lower DD&A expense in future periods. Once incurred, a write-down cannot be reversed.

The risk that we will be required to write-down the carrying value of our oil and natural gas properties increases when oil, NGLs, and natural gas prices are depressed or if we have large downward revisions in our estimated proved oil, NGLs, and natural gas reserves. Application of these rules during periods of relatively low prices, even if temporary, increases the chance of a ceiling test write-down. Based on the application of 12-month 2012 average unescalated prices of $94.71 per barrel of oil, $43.14 per barrel of NGLs, and $2.76 per Mcf of natural gas, then adjusted for price differentials, for the estimated life of the respective properties, the unamortized cost of our oil and natural gas properties at both the second and fourth quarters of 2012 exceeded the ceiling of our proved oil, NGLs, and natural gas reserves.

Derivative instruments qualifying as cash flow hedges are included in the computation of limitation on capitalized costs. For the quarter ended June 30, 2012, the 12-month average commodity prices, including the discounted value of our cash flow hedges, decreased significantly resulting in a non-cash ceiling test write down of $115.9 million pre-tax ($72.1 million, net of tax). Our qualifying cash flow hedges used in the ceiling test determination at June 30, 2012, consisted of swaps and collars, covering production of 0.0 MMBoe in 2012 and 0.0 MMBoe in 2013. The effect of those hedges on the June 30, 2012 ceiling test was a $32.5 million pre-tax increase in the discounted net cash flows of our oil and natural gas properties.

For the quarter ended December 31, 2012, the 12-month average commodity prices, including the discounted value of our cash flow hedges, also decreased significantly resulting in a further non-cash ceiling test write down of $167.7 million pre-tax ($104.4 million, net of tax). Our qualifying cash flow hedges used in the ceiling test determination at December 31, 2012, consisted of swaps and collars covering 0.0 MMBoe in 2013. The effect of those hedges on the December 31, 2012 ceiling test was a $29.8 million pre-tax increase in the discounted net cash flows of our oil and natural gas properties. Our oil and natural gas hedging is discussed in Note 13 of the Notes to our Consolidated Financial Statements.

If there are further declines in the 12-month average prices, including the discounted value of our commodity hedges, we may be required to record a write-down in future periods.

We use the sales method for recording natural gas sales. This method allows for the recognition of revenue, which may be more or less than our share of pro-rata production from certain wells. Our policy is to expense our pro-rata share of lease operating costs from all wells as incurred. The expenses relating to the wells in which we have an imbalance are not material.

Accounting for ARO for Oil, NGLs, and Natural Gas Properties. We record the fair value of liabilities associated with the retirement of assets having a long life. In our case, when the reserves in each of our oil or gas wells deplete or otherwise become uneconomical, we are required to incur costs to plug and abandon the wells. These costs are recorded in the period in which the liability is incurred (at the time the wells are drilled or acquired). We do not have any assets restricted for the purpose of settling these ARO liabilities. Our engineering staff uses historical experience to determine the estimated plugging costs taking into account the type of well (either oil or natural gas), the depth of the well and physical location of the well to determine the estimated plugging costs.

Accounting for Impairment of Long-Lived Assets. Drilling equipment, transportation equipment, gas gathering and processing systems, and other property and equipment are carried at cost less accumulated depreciation. Renewals and enhancements are capitalized while repairs and maintenance are expensed. Realization of the carrying value of property and equipment is reviewed for possible impairment whenever events or changes in circumstances suggest that these carrying amounts may not be recoverable. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset, including disposal value if any, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. The estimate of fair value is based on the best information available, including prices for similar assets. Changes in these estimates could cause us to reduce the carrying value of property and equipment. An estimate of the impact to our earnings if other assumptions had been used is not practicable because of the significant number of assumptions that would be involved in the estimates. In December 2012, our mid-stream segment had a $1.2 million write down of our Erick system. There was no volume from the wells connected to this system, the compressor and related surface equipment have been removed from this location and there is no future activity anticipated from this gathering system. No significant impairment was recorded at December 31, 2011 or 2010.

Goodwill. Goodwill represents the excess of the cost of acquisitions over the fair value of the net assets acquired. An annual impairment test is performed in the fourth quarter to determine whether the fair value has decreased and additionally

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when events indicate an impairment may have occurred. Goodwill is all related to our drilling segment, and accordingly, the impairment test is based on the estimated discounted future net cash flows of our drilling segment, utilizing discount rates and other factors in determining the fair value of our drilling segment. No goodwill impairment was recorded at December 31, 2012, 2011, or 2010.

Turnkey and Footage Drilling Contracts.   Because our contract drilling operations do not bear the risk of completion of a well being drilled under a “daywork” contract, we recognize revenues and expense generated under “daywork” contracts as the services are performed. Under “footage” and “turnkey” contracts we bear the risk of completion of the well, so revenues and expenses are recognized when the well is substantially completed. Substantial completion is determined when the well bore reaches the depth specified in the contract. The entire amount of a loss, if any, is recorded when the loss can be reasonably determined, however, any profit is recorded only at the time the well is finished. The costs of drilling contracts uncompleted at the end of the reporting period (which includes expenses incurred to date on “footage” or “turnkey” contracts) are included in other current assets. In 2012 and 2011, we did not drill any wells under turnkey or footage contracts. In 2010, we drilled four wells under a footage contract and none under a turnkey contract.

Accounting for Value of Stock Compensation Awards.   To account for stock-based compensation, compensation cost is measured at the grant date based on the fair value of an award and is recognized over the service period, which is usually the vesting period. We elected to use the modified prospective method, which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. The determination of the fair value of an award requires significant estimates and subjective judgments regarding, among other things, the appropriate option pricing model, the expected life of the award and performance vesting criteria assumptions. As there are inherent uncertainties related to these factors and our judgment in applying them to the fair value determinations, there is risk that the recorded stock compensation may not accurately reflect the amount ultimately earned by the employee.

Accounting for Derivative Instruments and Hedging.   We enter into derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of our future oil, NGLs, and natural gas production. We have hedged a portion of our anticipated production through December 2014. The accounting requires all derivatives to be recognized on the balance sheet and measured at fair value. If a derivative is designated as a cash flow hedge, we are required to measure the effectiveness of the hedge, or the degree that the gain (loss) for the hedging instrument offsets the loss (gain) on the hedged item, at each reporting period. The effective portion of the gain (loss) on the derivative instrument is recognized in other comprehensive income as a component of equity and subsequently reclassified into earnings when the forecasted transaction affects earnings. The ineffective portion of a derivative’s change in fair value is required to be recognized in earnings immediately.

We do not engage in derivative transactions for speculative purposes. In August 2012, we determined on a prospective basis, to enter into economic hedges without electing cash flow hedge accounting. Therefore, the change in fair value, on all commodity derivatives entered into after that determination, will be reflected in the income statement and not in accumulated other comprehensive income.

New Accounting Standards

Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards (IFRS). In May 2011, the FASB issued ASU 2011-04 Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS. ASU 2011-4 is intended to improve the comparability of fair value measurements presented and disclosed in financial statements prepared in accordance with U.S. GAAP and IFRS. The amendments are of two types: (i) those that clarify FASB’s intent about the application of existing fair value measurement and disclosure requirements and (ii) those that change

a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements. The update is effective for annual periods beginning after December 15, 2011. Other than modification to disclosure, there was no significant impact on our financial statements.
Presentation of Comprehensive Income. In June 2011, the FASB issued ASU 2011-05 – Presentation of Comprehensive Income. This ASU amends the Codification to allow an entity the option to present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. ASU 2011-05 eliminates the option to present the components of other comprehensive income as part of the statement of changes in stockholders' equity. The amendments to the Codification in the ASU 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. ASU 2011-05 should be applied retrospectively. The amendments

are effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. We chose to present net income and comprehensive income as two consecutive statements in our financial statements.
In February 2013, the FASB issued ASU 2013-02 to address the presentation of comprehensive income related to ASU 2011-05. The standard requires that companies present either in a single note or parenthetically on the face of the financial statements, the effect of significant amounts reclassified from each component of accumulated other comprehensive income based on its source (e.g., the release due to cash flow hedges from interest rate contracts) and the income statement line items affected by the reclassification (e.g., interest income or interest expense). The amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2012. We are in the process of evaluating the option we will choose to present comprehensive income and the impact it will have on our financial statements.
Disclosures about Offsetting Assets and Liabilities. In January 2011, the FASB issued ASU 2011-11 – Disclosures about Offsetting Assets and Liabilities. Unlike IFRS, U.S. GAAP allows companies the option to present net in their balance sheets derivatives that are subject to a legally enforceable netting arrangement with the same party where rights of set-off are only available in the event of default or bankruptcy. To address these differences between IFRS and U.S. GAAP, the FASB and the IASB (the Boards) issued an exposure draft that proposed new criteria for netting that were narrower than the current conditions currently in U.S. GAAP. Nevertheless, in response to feedback from their respective stakeholders, the Boards decided to retain their existing offsetting models. Instead, the Boards have issued common disclosure requirements related to offsetting arrangements to allow investors to better compare financial statements prepared in accordance with IFRS or U.S. GAAP. The amendments in this ASU 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. An entity is required to apply the amendments for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. An entity should provide the disclosures required by those amendments retrospectively for all comparative periods presented. We are in the process of evaluating the impact this will have on our financial statements.

Financial Condition and Liquidity

Summary.

Our financial condition and liquidity depends on the cash flow from our operations and borrowings under our credit agreement. The principal factors determining the amount of our cash flow are:
- the demand for and the dayrates we receive for our drilling rigs;
- the quantity of oil, NGLs, and natural gas we produce;
- the prices we receive for our oil, NGLs, and natural gas production; and
- the margins we obtain from our natural gas gathering and processing contracts.

The following is a summary of certain financial information as of December 31, and for the years ended December 31:

	2012		2011		2010	
	(In thousands except percentages)					
Working capital	$(11,495	)	$15,715		$41,052	
Long-term debt	$716,359		$300,000		$163,000	
Shareholders' equity	$1,974,301	[1]	$1,947,017		$1,710,617	
Ratio of long-term debt to total capitalization	27	%[1]	13	%	9	%
Net income	$23,176	[1]	$195,867		$146,484	
Net cash provided by operating activities	$690,911		$608,455		$390,072	
Net cash used in investing activities	$(1,079,042	)	$(768,236	)	$(536,261	)
Net cash provided by financing activities	$388,270		$159,257		$146,408	

(1) In June and December 2012, we incurred a non-cash ceiling test write down of our oil and natural gas properties of $115.9 million and $167.7 million pre-tax ($72.1 million and $104.4 million, net of tax), respectively, due to low 12-month average commodity prices at quarter-end. The write downs impacted our 2012 shareholders’ equity, ratio of long-term debt to total capitalization and net income. There was no impact on our compliance with the covenants contained in our credit agreement.

The following table summarizes certain operating information for the years ended December 31:

	2012	2011	2010
Contract Drilling:			
Average number of our drilling rigs in use during the period	73.9	76.1	61.4
Total number of drilling rigs owned at the end of the period	127	127	121
Average dayrate	$19,949	$18,842	$15,478
Oil and Natural Gas:			
Oil production (MBbls)	3,279	2,511	1,521
Natural gas liquids production (MBbls)	2,796	2,239	1,549
Natural gas production (MMcf)	48,930	44,104	40,756
Average oil price per barrel received	$92.60	$87.18	$69.52
Average oil price per barrel received excluding hedges	$90.19	$93.49	$76.65
Average NGLs price per barrel received	$31.58	$43.64	$37.04
Average NGLs price per barrel received excluding hedges	$30.70	$44.44	$36.96
Average natural gas price per mcf received	$3.37	$4.26	$5.62
Average natural gas price per mcf received excluding hedges	$2.53	$3.78	$4.05
Mid-Stream:			
Gas gathered—MMBtu/day	288,799	215,805	183,867
Gas processed—MMBtu/day	165,511	116,161	82,175
Gas liquids sold—gallons/day	542,578	412,064	271,360
Number of natural gas gathering systems	39	35	34
Number of processing plants	14	10	10

At December 31, 2012, we had unrestricted cash totaling $1.0 million and had borrowed $71.1 million of the $500.0 million we have currently available under our credit agreement. Our credit agreement is used primarily for working capital and capital expenditures.

On May 18, 2011, we completed the sale of $250.0 million aggregate principal amount of 6.625% Senior Subordinated Notes (the 2011 Notes) due 2021. The 2011 Notes were issued at par and mature on May 15, 2021. The net proceeds were used to repay outstanding borrowings under our credit agreement, which had $220.3 million outstanding as of May 18, 2011. The remaining proceeds were used for general working capital purposes.

On July 24, 2012, we completed the sale of $400.0 million aggregate principal amount of unregistered senior subordinated notes (the 2012 Notes) due May 15, 2021, which bear interest at a rate of 6.625% per year. The 2012 Notes were sold at 98.75% of par plus accrued interest from May 15, 2012. We used the net proceeds from the offering to partially finance the acquisition of oil and natural gas properties from Noble. We incurred $8.7 million of fees that are being amortized as debt issuance cost over the life of the 2012 Notes.

On November 13, 2012, we registered with the SEC on Form S-4 an offer to exchange the 2012 Notes for additional notes with materially identical terms to our existing 2011 Notes, which were registered under the Securities Act. On January 7, 2013, the exchange of the 2012 Notes was completed. The notes issued in exchange for the 2012 Notes are now registered and treated as a single series of debt securities with the 2011 Notes, bringing the total to $650.0 million aggregate principal amount of 6.625% senior subordinated notes (the Notes). The interest is payable semi-annually (in arrears) on May 15 and November 15 of each year, and the Notes will mature on May 15, 2021.

Working Capital

Typically, our working capital balance varies primarily because of the timing of our trade accounts receivable and accounts payable and from the fluctuation in current assets and liabilities associated with the mark to market value of our hedging activity. We had negative working capital of $11.5 million as of December 31, 2012 and positive working capital of

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$15.7 million and $41.1 million as of December 31, 2011 and 2010, respectively. The effect of our derivatives increased working capital by $9.6 million, $18.0 million, and $5.4 million as of December 31, 2012, 2011, and 2010, respectively.

Contract Drilling

Many factors influence the number of drilling rigs we are working at any given time as well as the costs and revenues associated with that work. These factors include the demand for drilling rigs in our areas of operation, competition from other drilling contractors, the prevailing prices for oil, NGLs, and natural gas, availability and cost of labor to run our drilling rigs, and our ability to supply the equipment needed.

Competition to keep qualified labor continues. We increased compensation for rig personnel in the Rocky Mountain division during the first quarter of 2012. We do not currently anticipate any further increases in 2013.

With the weakened natural gas market, operators have been more focused on drilling for oil and NGLs. With this focus operators are also shifting toward drilling in shallower oil plays, like the Mississippian and Permian plays, potentially resulting in a change in the mix of our working drilling rigs. These shallower plays tend to use drilling rigs with lower horsepower which tend to have a lower dayrate and margin. The future demand for and the availability of drilling rigs to meet that demand will have an impact on our future dayrates. For 2012, our average dayrate was $19,949 per day compared to $18,842 per day for 2011. Our average number of drilling rigs used in 2012 was 73.9 drilling rigs (58%) compared with 76.1 drilling rigs (61%) in 2011. Based on the average utilization of our drilling rigs during 2012, a $100 per day change in dayrates has a $7,390 per day ($2.7 million annualized) change in our pre-tax operating cash flow.

Our contract drilling segment provides drilling services for our exploration and production segment. Depending on their timing some of the drilling services performed on our properties are also deemed to be associated with the acquisition of an ownership interest in the property. Revenues and expenses for such services are eliminated in our income statement, with any profit recognized as a reduction in our investment in our oil and natural gas properties. The contracts for these services are issued under the same conditions and rates as the contracts entered into with unrelated third parties. We eliminated revenue of $49.6 million, $52.2 million, and $40.1 million for 2012, 2011, and 2010, respectively, from our contract drilling segment and eliminated the associated operating expense of $34.1 million, $32.6 million, and $31.0 million during 2012, 2011, and 2010, respectively, yielding $15.5 million, $19.6 million, and $9.1 million during 2012, 2011, and 2010, respectively, as a reduction to the carrying value of our oil and natural gas properties.

Impact of Prices for Our Oil, NGLs, and Natural Gas

Any significant change in oil, NGLs, or natural gas prices has a material effect on our revenues, cash flow and, the value of our oil, NGLs, and natural gas reserves. Generally, prices and demand for domestic natural gas are influenced by weather conditions, supply imbalances, and by worldwide oil price levels. Domestic oil prices are primarily influenced by world oil market developments. All of these factors are beyond our control and we cannot predict nor measure their future influence on the prices we will receive.

Based on our production in 2012, a $0.10 per Mcf change in what we are paid for our natural gas production, without the effect of hedging, would result in a corresponding $386,000 per month ($4.6 million annualized) change in our pre-tax operating cash flow. Our 2012 average natural gas price was $3.37 compared to an average natural gas price of $4.26 for 2011 and $5.62 for 2010. A $1.00 per barrel change in our oil price, without the effect of hedging, would have a $259,000 per month ($3.1 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGLs prices, without the effect of hedging, would have a $220,000 per month ($2.6 million annualized) change in our pre-tax operating cash flow based on our production in 2012. Our 2012 average oil price per barrel was $92.60 compared with an average oil price of $87.18 in 2011 and $69.52 in 2010, and our 2012 average NGLs price per barrel was $31.58 compared with an average NGLs price of $43.64 in 2011 and $37.04 in 2010.

Because commodity prices have an effect on the value of our oil, NGLs, and natural gas reserves, declines in those prices can result in a decline in the carrying value of our oil and natural gas properties. Price declines can also adversely affect the semi-annual determination of the amount available for us to borrow under our credit agreement since that determination is based mainly on the value of our oil, NGLs, and natural gas reserves. A reduction could limit our ability to carry out our planned capital projects.

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Our natural gas production is sold to intrastate and interstate pipelines, to independent marketing firms and gatherers under contracts with terms generally ranging anywhere from one month to five years. Our oil production is sold to independent marketing firms generally under six month contracts.

Mid-Stream Operations

This segment is engaged primarily in the buying, selling, gathering, processing, and treating of natural gas and operates three natural gas treatment plants, 14 processing plants, 39 gathering systems, and approximately 1,300 miles of pipeline. Our operations are located in Oklahoma, Texas, Kansas, Pennsylvania, and West Virginia. This segment enhances our ability to gather and market not only our own natural gas and NGLs but also that owned by third parties and serves as a mechanism through which we can construct or acquire existing natural gas gathering and processing facilities. During 2012, 2011, and 2010 this segment purchased $68.2 million, $71.5 million, and $42.4 million, respectively, of our natural gas production and NGLs, and provided gathering and transportation services of $5.1 million, $4.6 million, and $4.4 million, respectively. Intercompany revenue from services and purchases of production between this business segment and our oil and natural gas segment has been eliminated in our consolidated financial statements.

Our mid-stream segment gathered an average of 288,799 MMBtu per day in 2012 compared to 215,805 MMBtu per day in 2011 and 183,867 MMBtu per day in 2010. It processed an average of 165,511 MMBtu per day in 2012 compared to 116,161 MMBtu per day in 2011 and 82,175 MMBtu per day in 2010, and sold NGLs of 542,578 gallons per day in 2012 compared to 412,064 gallons per day in 2011 and 271,360 gallons per day in 2010. Gas gathering volumes per day in 2012 increased primarily from wells connected to our systems throughout 2011 and 2012. Volumes processed increased primarily due to the addition of wells connected and recent upgrades to several of our processing systems. NGLs sold increased primarily due to the addition of wells connected and recent upgrades to several of our processing systems.

Our Credit Agreement and Senior Subordinated Notes

Credit Agreement. On September 5, 2012, we amended our Senior Credit Agreement (credit agreement) scheduled to mature on September 13, 2016. The amount available to be borrowed is the lesser of the amount we elect (from time to time) as the commitment amount (amended to $500.0 million from $250.0 million) or the value of the borrowing base as determined by the lenders (amended to $800.0 million from $600.0 million), but in either event not to exceed the maximum credit agreement amount of $900.0 million (amended from $750.0 million). We are charged a commitment fee ranging from 0.375 to 0.50 of 1% on the amount available but not borrowed. The rate varies based on the amount borrowed as a percentage of the amount of the total borrowing base. In connection with this new amendment, we paid $1.5 million in origination, agency, syndication, and other related fees. We are amortizing these fees over the life of the credit agreement. At February 15, 2013, borrowings were $67.5 million; at December 31, 2012, borrowings were $71.1 million.

The current lenders under our credit agreement and their respective participation interests are as follows:

Lender	Participation Interest	
BOK (BOKF, NA, dba Bank of Oklahoma)	17	%
BBVA Compass Bank	17	%
Bank of Montreal	15	%
Bank of America, N.A.	15	%
Comerica Bank	8	%
Crédit Agricole Corporate and Investment Bank, London Branch	8	%
Wells Fargo Bank, National Association	8	%
Canadian Imperial Bank of Commerce	8	%

The Bank of Nova Scotia	4	%
	100	%

The amount of the borrowing base, which is subject to redetermination by the lenders on April 1st and October 1st of each year, is based primarily on a percentage of the discounted future value of our oil and natural gas reserves. We or the lenders may request a onetime special redetermination of the borrowing base between each scheduled redetermination. In

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addition, we may request a redetermination following the completion of an acquisition that meets the requirements set forth in the credit agreement.

At our election, any part of the outstanding debt under the credit agreement may be fixed at a London Interbank Offered Rate (LIBOR). LIBOR interest is computed as the sum of the LIBOR base for the applicable term plus 1.75% to 2.50% depending on the level of debt as a percentage of the borrowing base and is payable at the end of each term, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the prime rate specified in the agreement,which cannot be less than LIBOR plus 1.00%. Interest is payable at the end of each month, and the principal may be repaid in whole or in part at anytime, without a premium or penalty. At December 31, 2012, we had $71.1 million in outstanding borrowings under our credit agreement with an interest rate of 2.9%.

We can use borrowings for financing general working capital requirements for (a) exploration, development, production and acquisition of oil and gas properties, (b) acquisitions and operation of mid-stream assets, (c) issuance of standby letters of credit, (d) contract drilling services, and (e) general corporate purposes.

The credit agreement prohibits, among other things:

- the payment of dividends (other than stock dividends) during any fiscal year in excess of 30% of our consolidated net income for the preceding fiscal year;
- the incurrence of additional debt with certain limited exceptions; and
- the creation or existence of mortgages or liens, other than those in the ordinary course of business, on any of our properties, except in favor of our lenders.

The credit agreement also requires that we have at the end of each quarter:

- a current ratio (as defined in the credit agreement) of not less than 1 to 1; and
- a leverage ratio of funded debt to consolidated EBITDA (as defined in the credit agreement) for the most recently ended rolling four fiscal quarters of no greater than 4 to 1.

As of December 31, 2012, we were in compliance with the covenants contained in the credit agreement.

6.625% Senior Subordinated Notes. On May 18, 2011, we completed the sale of $250.0 million aggregate principal amount of our 6.625% Senior Subordinated Notes due 2021 (the 2011 Notes). The Notes were issued at par and mature on May 15, 2021. We received net proceeds of approximately $244.0 million after deducting fees of approximately $6.0 million. Those fees are being amortized as deferred financing costs over the life of the Notes. We used the net proceeds to repay outstanding borrowings under our credit agreement, which was $220.3 million on May 18, 2011. The remaining proceeds were used for general working capital purposes.

On July 24, 2012, we completed the sale of $400.0 million aggregate principal amount of unregistered senior subordinated notes (the 2012 Notes) due May 15, 2021, which bear interest at a rate of 6.625% per year. The 2012 Notes were sold at 98.75% of par plus accrued interest from May 15, 2012. We used the net proceeds from the offering to partially finance the acquisition of oil and natural gas properties from Noble. We incurred $8.7 million of fees that are being amortized as debt issuance cost over the life of the 2012 Notes.

On November 13, 2012, we registered with the SEC on Form S-4 an offer to exchange the 2012 Notes for additional notes with materially identical terms to our existing 2011 Notes, which were registered under the Securities Act. On January 7, 2013, the exchange of the 2012 Notes was completed. The notes issued in exchange for the 2012 Notes are now registered and treated as a single series of debt securities with the 2011 Notes, bringing the total to $650.0 million aggregate principal amount of 6.625% senior subordinated notes (the Notes). The interest is payable semi-annually (in arrears) on May 15 and November 15 of each year, and the Notes will mature on May 15, 2021.

The notes are guaranteed by our 100% owned domestic direct and indirect subsidiaries (the Guarantors). Unit, as the parent company, has no independent assets or operations. The guarantees registered under the registration statement are full and unconditional and joint and several, subject to certain automatic customary releases, including sale, disposition, or transfer of the capital stock or substantially all of the assets of a subsidiary guarantor, exercise of legal defeasance option or covenant defeasance option, and designation of a subsidiary guarantor as unrestricted in accordance with the governing Indenture. Any subsidiaries of Unit other than the Guarantors are minor. There are no significant restrictions on the ability of Unit to receive funds from its subsidiaries through dividends, loans, advances, or otherwise.

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The Notes are subject to an Indenture dated as of May 18, 2011, between us and Wilmington Trust, National Association (successor to Wilmington Trust FSB), as Trustee (the Trustee), as supplemented by the First Supplemental Indenture thereto dated as of May 18, 2011, between us, the Guarantors, and the Trustee, and as further supplemented by that the Second Supplemental Indenture thereto dated as of January 7, 2013, between us, the Guarantors and the Trustee, establishing the terms and providing for the issuance of the Notes (as supplemented, the 2011 Indenture). The discussion of the Notes in this report is qualified by and subject to the actual terms of the 2011 Indenture .

On and after May 15, 2016, we may redeem all or, from time to time, a part of the Notes at certain redemption prices, plus accrued and unpaid interest. Before May 15, 2014, we may on any one or more occasions redeem up to 35% of the original principal amount of the Notes with the net cash proceeds of one or more equity offerings at a redemption price of 106.625% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, provided that at least 65% of the original principal amount of the Notes remains outstanding after each redemption. In addition, at any time before May 15, 2016, we may redeem the Notes, in whole or in part, at a redemption price equal to 100% of the principal amount plus a “make whole” premium, plus accrued and unpaid interest, if any, to the redemption date. If a “change of control” occurs, subject to certain conditions, we must offer to repurchase from each holder all or any part of that holder’s Notes at a purchase price in cash equal to 101% of the principal amount of the Notes plus accrued and unpaid interest, if any, to the date of purchase. The Indenture contains customary events of default. The Indenture contains covenants that, among other things, limit our ability and the ability of certain of our subsidiaries to incur or guarantee additional indebtedness; pay dividends on our capital stock or redeem capital stock or subordinated indebtedness; transfer or sell assets; make investments; incur liens; enter into transactions with our affiliates; and merge or consolidate with other companies. We were in compliance with all covenants of the Notes as of December 31, 2012.

Capital Requirements

Drilling Dispositions, Acquisitions, and Capital Expenditures. During the first half of 2010, we sold eight of our idle mechanical drilling rigs to an unaffiliated party. These drilling rigs ranged in horsepower from 800 to 1,000. Proceeds from this sale were $23.9 million resulting in a gain of $5.7 million which we recorded in the first quarter of 2010. The proceeds were used to refurbish and upgrade existing drilling rigs in our fleet allowing those drilling rigs to be used in horizontal drilling operations. We also placed into service in our Rocky Mountain division a 1,500 horsepower, diesel-electric drilling rig that previously had been placed on hold during 2009 by our customer.

In September 2010, we entered into a contract with an unaffiliated party under which we conveyed three of our idle mechanical drilling rigs and, in exchange, received a 1,200 horsepower electric drilling rig and $5.3 million. The three drilling rigs sold ranged in horsepower from 650 to 1,000. The transaction was closed in October and resulted in a gain of $3.5 million.

At the end of 2010, we began constructing five new 1,500 horsepower, diesel-electric drilling rigs. All of these drilling rigs are now operational and located in the Bakken shale in North Dakota.

During 2011, we were awarded two additional new build contracts for 1,500 horsepower, diesel-electric drilling rigs. One was placed into service during the fourth quarter of 2011 and the other was placed in service during the first quarter of 2012, both in Wyoming.
During the first quarter of 2012, we sold an idle 600 horsepower mechanical drilling rig to an unaffiliated third-party. Additionally, during the second quarter of 2012, we placed another new 1,500 horsepower, diesel-electric drilling rig in North Dakota under a three year contract.

During the third quarter of 2012, we had a fire on one of our drilling rigs. We expect that all of the net book value of the damaged equipment will be recoverable from insurance proceeds. As a result of this loss, this segment now has 127 drilling rigs in its fleet. No personnel were injured in this incident.

Our anticipated 2013 capital expenditures for this segment are $98.0 million. We have spent $77.5 million for capital expenditures during 2012 compared to $162.2 million in 2011, and $118.8 million in 2010.

Oil and Natural Gas Dispositions, Acquisitions, and Capital Expenditures. Most of our capital expenditures for this segment are discretionary and directed toward future growth. Any decision to increase our oil, NGLs, and natural gas reserves through acquisitions or through drilling depends on the prevailing or expected market conditions, potential return on investment, future drilling potential, and opportunities to obtain financing under the circumstances involved, all of which

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provide us with a large degree of flexibility in deciding when and if to incur these costs. We completed drilling 171 gross wells (80.08 net wells) in 2012 compared to 160 gross wells (82.42 net wells) in 2011, and 167 gross wells (87.52 net wells) in 2010. Our 2012 total capital expenditures for our oil and natural gas segment, excluding a $45.1 million ARO liability, and $579.0 million for acquisitions, totaled $504.2 million compared to 2011 capital expenditures of $506.7 million (excluding a $23.3 million ARO liability and $50.0 million for acquisitions), and 2010 capital expenditures of $361.4 million (excluding a $9.9 million ARO liability and $92.6 million for acquisitions). Currently we plan to participate in drilling approximately 180 gross wells in 2013 and estimate our total capital expenditures (excluding any possible acquisitions) for our oil and natural gas segment will be approximately $586.0 million. Whether we are able to drill the full number of wells we are planning is dependent on a number of factors, many of which are beyond our control and include the availability of drilling rigs, availability of pressure pumping services, prices for oil, NGLs, and natural gas, demand for oil, NGLs, and natural gas, the cost to drill wells, the weather, and the efforts of outside industry partners.

On June 2, 2010, we completed an acquisition of oil and natural gas properties from certain unaffiliated parties in an effort to explore and develop more oil rich plays. The properties were purchased for approximately $73.7 million in cash, after post-closing adjustments. The purchase price allocation was $48.7 million for proved properties and $25.0 million for undeveloped leasehold not being amortized. The acquisition included approximately 45,000 net leasehold acres and 10 producing oil wells. This acquisition targeted the Marmaton horizontal oil play located mainly in Beaver County, Oklahoma.

On July 20, 2011, we acquired certain producing properties from an unaffiliated seller for approximately $12.3 million in cash, after post-closing adjustments, consisting of 30 operated wells and 59 non-operated well interests located in Beaver, Harper, and Ellis Counties, Oklahoma and Lipscomb County, Texas. The purchase price allocation was $8.4 million for proved properties and $3.9 million for acreage.

On August 31, 2011, we acquired certain producing oil and gas properties for $30.5 million in cash from an unaffiliated seller. Included in the acquisition were more than 500 wells located principally in the Oklahoma Arkoma Woodford and Hartshorne Coal plays along with other properties located throughout Oklahoma and Texas. The acquisition also included approximately 55,000 net acres of which 96% was held by production.

On September 17, 2012, we closed on the acquisition of certain oil and natural gas assets from Noble. After final closing adjustments, the acquisition included approximately 83,000 net acres primarily in the Granite Wash, Cleveland, and various other plays in western Oklahoma and the Texas Panhandle. The adjusted amount paid was $592.6 million.

Also in September 2012, we sold our interest in certain Bakken properties (representing approximately 35% of our total acreage in the Bakken play). The proceeds, net of related expenses, were $226.6 million. In addition, we sold certain oil and natural gas assets located in Brazos and Madison Counties, Texas for approximately $44.1 million. Both dispositions were accounted for as adjustments to the full cost pool with no gain or loss recognized.

Mid-Stream Dispositions, Acquisitions, and Capital Expenditures. During the second quarter of 2012, we completed the installation of our fifth processing plant at our Hemphill County, Texas facility. We now have the capacity to process 160 MMcf per day of our own and third-party Granite Wash natural gas production.

At our Cashion facility, we have extended our gathering system to the north to connect wells that are being drilled in that area. Due to this increased activity, we have installed an additional 25 MMcf per day processing plant at our Cashion facility. The installation of the new 25 MMcf per day high efficiency turbo-expander processing plant became operational in March 2012. With the installation of this additional plant, our total processing capacity increased to approximately 45 MMcf per day at our Cashion facility.

In the Mississippian play in north central Oklahoma, a new gas gathering system and processing plant in Noble and Kay Counties, known as the Bellmon system, was completed and began operating late in the second quarter. This system currently consists of approximately 83 miles of pipe with a 20 MMcf per day gas processing plant. An additional 30 MMcf per day gas processing plant is scheduled to be installed in the first quarter of 2013. We also connected our existing Remington gathering system to the new Bellmon system which required laying approximately 26 miles of pipeline and installing related compression services. In addition to these projects, we completed the installation of a NGLs line from our Bellmon plant to Medford, Oklahoma. This project consists of approximately 20 miles of 6” pipe and was completed in the 4th quarter of 2012.

We are continuing to expand operations in the Appalachian region. In the fourth quarter of 2012, construction was completed on the first phase of our gathering facility in Allegheny and Butler Counties, Pennsylvania, known as the Pittsburgh Mills system. The first phase of this project consists of approximately seven miles of gathering pipeline. In the first quarter of 2013, the related compressor station will be completed. We currently have 10 wells connected to this gathering system. The

current gathered volumes from these wells is approximately 28 MMcf per day. Construction activity for expansion of this pipeline continues as the producer is maintaining its drilling activity.
In December 2012, we had a $1.2 million write-down of our Erick system. There was no volume from the wells connected to this system, the compressor and related surface equipment have been removed from this location and there is no future activity anticipated from this gathering system.
During 2012, our mid-stream segment incurred $183.2 million in capital expenditures ($18.7 million on four gathering systems acquired in the Noble acquisition) as compared to $79.4 million in 2011 and $29.8 million in 2010, including acquisitions. For 2013, our estimated capital expenditures (excluding acquisitions) are $105.0 million. At December 31, 2012, we had committed to purchase a processing plant for the remaining payment of $1.8 million within the next twelve months.

Contractual Commitments

At December 31, 2012, we had the following contractual obligations:

	Payments Due by Period				
	Total	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
	(In thousands)				
Long-term debt (1)	$1,099,891	$45,091	$90,183	$158,648	$805,969
Operating leases (2)	12,615	8,374	3,852	389	—
Processing plant (3)	1,775	1,775	—	—	—
Total contractual obligations	$1,114,281	$55,240	$94,035	$159,037	$805,969

(1) See previous discussion in MD&A regarding our long-term debt. This obligation is presented in accordance with the terms of the Notes and credit agreement and includes interest calculated using our December 31, 2012 interest rates of 6.625% for the Notes and 2.9% for the credit agreement.
(2) We lease office space or yards in Edmond, Oklahoma City, and Tulsa, Oklahoma; Houston, Texas; Englewood, Colorado; Pinedale, Wyoming; and Pittsburgh, Pennsylvania under the terms of operating leases expiring through September, 2017. Additionally, we have several equipment leases and lease space on short-term commitments to stack excess drilling rig equipment and production inventory.
(3) We have committed to pay $1.8 million for a processing plant over the next twelve months.

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At December 31, 2012, we also had the following commitments and contingencies that could create, increase or accelerate our liabilities:

Other Commitments	Estimated Amount of Commitment Expiration Per Period Total Accrued	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
	(In thousands)				
Deferred compensation plan (1)	$2,779	Unknown	Unknown	Unknown	Unknown
Separation benefit plans (2)	$7,972	$665	Unknown	Unknown	Unknown
Derivative liabilities—commodity hedges	$2,510	$1,948	$562	$—	$—
ARO liability (3)	$146,159	$2,953	$45,794	$6,865	$90,547
Gas balancing liability (4)	$3,838	Unknown	Unknown	Unknown	Unknown
Repurchase obligations (5)	$—	Unknown	Unknown	Unknown	Unknown
Workers' compensation liability(6)	$18,517	$8,664	$3,097	$1,161	$5,595

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(1) We provide a salary deferral plan which allows participants to defer the recognition of salary for income tax purposes until actual distribution of benefits, which occurs at either termination of employment, death or certain defined unforeseeable emergency hardships. We recognize payroll expense and record a liability, included in other long-term liabilities in our Consolidated Balance Sheets, at the time of deferral.

(2) Effective January 1, 1997, we adopted a separation benefit plan ("Separation Plan"). The Separation Plan allows eligible employees whose employment with us is involuntarily terminated or, in the case of an employee who has completed 20 years of service, voluntarily or involuntarily terminated, to receive benefits equivalent to four weeks salary for every whole year of service completed with the company up to a maximum of 104 weeks. To receive payments the recipient must waive certain claims against us in exchange for receiving the separation benefits. On October 28, 1997, we adopted a Separation Benefit Plan for Senior Management ("Senior Plan"). The Senior Plan provides certain officers and key executives of the company with benefits generally equivalent to the Separation Plan. The Compensation Committee of the Board of Directors has absolute discretion in the selection of the individuals covered in this plan. On May 5, 2004 we also adopted the Special Separation Benefit Plan ("Special Plan"). This plan is identical to the Separation Benefit Plan with the exception that the benefits under the plan vest on the earliest of a participant's reaching the age of 65 or serving 20 years with the company. On December 31, 2008, all these plans were amended to bring the plans into compliance with Section 409A of the Internal Revenue Code of 1986, as amended.

(3) When a well is drilled or acquired, under ASC 410 "Accounting for Asset Retirement Obligations," we record the fair value of liabilities associated with the retirement of long-lived assets (mainly plugging and abandonment costs for our depleted wells).

(4) We have recorded a liability for those properties we believe do not have sufficient oil, NGLs, and natural gas reserves to allow the under-produced owners to recover their under-production from future production volumes.

(5) We formed The Unit 1984 Oil and Gas Limited Partnership and the 1986 Energy Income Limited Partnership along with private limited partnerships (the "Partnerships") with certain qualified employees, officers and directors from 1984 through 2011, with a subsidiary of ours serving as general partner. The Partnerships were formed for the purpose of conducting oil and natural gas acquisition, drilling and development operations and serving as co-general partner with us in any additional limited partnerships formed during that year. The Partnerships participated on a proportionate basis with us in most drilling operations and most producing property acquisitions commenced by us for our own account during the period from the formation of the Partnership through December 31 of that year. These partnership agreements require, on the election of a limited partner, that we repurchase the limited partner's interest at amounts to be determined by appraisal in the future. Repurchases in any one year are limited to 20% of the units outstanding. We made repurchases of $56,000 in 2012 and $22,000 in both

2011 and 2010.

(6) We have recorded a liability for future estimated payments related to workers' compensation claims primarily associated with our contract drilling segment.

Derivative Activities

Periodically we enter into derivative transactions locking in the prices to be received for a portion of our oil, NGLs, and natural gas production. In August 2012, we determined on a prospective basis to enter into economic hedges without electing cash flow hedge accounting. Therefore, the change in fair value, on all commodity derivatives entered into after that determination, will be reflected in the income statement and not in accumulated other comprehensive income.

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Commodity Hedges. Our commodity hedging is intended to reduce our exposure to price volatility and manage price risks. Our decision on the type and quantity of our production and the price(s) of our hedge(s) is based, in part, on our view of current and future market conditions. As of December 31, 2012, based on our 2012 average daily production, the approximated percentages of our production that we have hedged are as follows:

	Hedge Designation			
	Cash Flow 2013	Mark-to-Market 2013	Total 2013	Mark-to-Market 2014
Daily oil production	61 %	11 %	72 %	11 %
Daily natural gas production	60 %	15 %	75 %	— %

With respect to the commodities subject to our hedges, the use of hedging limits the risk of adverse downward price movements. However, it also limits increases in future revenues that would otherwise result from price movements above the hedged prices.

The use of derivative transactions carries with it the risk that one or more of the counterparties may not be able to meet their financial obligations under the transactions. Based on our evaluation at December 31, 2012, we determined that there was no material risk of non-performance by any of our counterparties. At December 31, 2012, the fair values of the net assets (liabilities) we had with each of the counterparties to our commodity derivative transactions are as follows:

	December 31, 2012
	(In millions)
Comerica Bank	$8.1
Canadian Imperial Bank of Commerce	2.9
Bank of Montreal	2.6
BBVA Compass Bank	1.4
Bank of America, N.A.	(1.0)
Total assets (liabilities)	$14.0

If a legal right of set-off exists, we net the value of the derivative arrangements we have with the same counterparty in our consolidated balance sheets. At December 31, 2012, we recorded the fair value of our commodity derivatives on our balance sheet as current derivative assets of $16.5 million and current and non-current derivative liabilities of $1.9 million and $0.6 million, respectively. At December 31 2011, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current derivative assets of $31.9 million and $4.5 million, respectively, and current derivative liabilities of $2.7 million.

We recognize in accumulated other comprehensive income the effective portion of any changes in fair value on our cash flow hedges and reclassify the recognized gains (losses) on the sales to revenue and the purchases to expense as the underlying transactions are settled. As of December 31, 2012, we had a gain of $7.6 million, net of tax from our oil and natural gas segment derivatives in accumulated other comprehensive income.

Based on market prices at December 31, 2012, we expect to transfer to earnings a gain of approximately $7.6 million, net of tax, of the gain included in accumulated other comprehensive income during the next 12 months in the related month of production. The commodity derivative instruments under cash flow accounting existing as of December 31, 2012 are expected to mature by December 2013. For our economic hedges that we elected not to apply cash flow accounting to, any changes in their fair value occurring before their maturity (i.e., temporary fluctuations in value) are reported in gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net in our consolidated statements of income. Changes in the fair value of derivatives designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized into earnings. When the hedged item is recognized into earnings, it is reported in oil and natural gas revenues. Any change in fair value resulting from ineffectiveness is recognized in gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net. Previously, we reported all

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realized and unrealized gains (losses) in oil and natural gas revenues and now we reflect gains (losses) on non-designated hedges and ineffectiveness from cash flow hedges along with other revenue items in other income (expense) below income from operations. Prior year amounts have been reclassified to conform to current year presentation. These gains (losses) are as follows at December 31:

	2012	2011	2010
	(In thousands)		
Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net:			
Realized gains (losses) on derivatives not designated as hedges	$—	$(711)	$—
Unrealized gains (losses) on derivatives not designated as hedges	1,373	(336)	336
Unrealized gains (losses) on ineffectiveness of cash flow hedges	(2,616)	2,749	700
	$(1,243)	$1,702	$1,036

Stock and Incentive Compensation

During 2012, we granted awards covering 401,051 shares of restricted stock. These awards were granted as retention incentive awards. These stock awards had an estimated fair value as of the grant date of $16.9 million. Compensation expense will be recognized over the awards' three year vesting period. During 2012, we recognized $6.5 million in additional compensation expense and capitalized $1.5 million for these awards. During 2011, we granted awards covering 211,050 shares of restricted stock. These awards were granted as retention incentive awards and are being recognized over their two and three year vesting periods. During 2010, we granted awards covering 450,355 shares of restricted stock. These awards were granted as retention incentive awards and are being recognized over their two and three year vesting periods. No SAR awards were made during 2012, 2011, or 2010.

During 2012, we recognized compensation expense of $11.4 million for our restricted stock grants and capitalized $2.7 million of compensation cost for oil and natural gas properties.

Insurance

We are self-insured for certain losses relating to workers’ compensation, control of well, and employee medical benefits. Insured policies for other coverages contain deductibles or retentions per occurrence that range from $50,000 to $1.5 million. We have purchased stop-loss coverage in order to limit, to the extent feasible, per occurrence and aggregate exposure to certain types of claims. However, there is no assurance that the insurance coverages we have will adequately protect us against liability from all potential consequences. We have elected to use an ERISA governed occupational injury benefit plan to cover our drilling segment employees in Texas in lieu of covering them under Texas Workers’ Compensation. If insurance coverage becomes more expensive, we may choose to self-insure, decrease our limits, raise our deductibles or any combination of these rather than pay higher premiums.

Oil and Natural Gas Limited Partnerships and Other Entity Relationships.

We are the general partner of 16 oil and natural gas partnerships which were formed privately or publicly. Each partnership’s revenues and costs are shared under formulas set out in that partnership’s agreement. The partnerships repay us for contract drilling, well supervision and general and administrative expense. Related party transactions for contract drilling and well supervision fees are the related party’s share of such costs. These costs are billed on the same basis as billings to unrelated third parties for similar services. General and administrative reimbursements consist of direct general and administrative expense incurred on the related party’s behalf as well as indirect expenses assigned to the related parties. Allocations are based on the related party’s level of activity and are considered by us to be reasonable. During 2012, 2011, and 2010, the total we received for all of these fees was $0.7 million, $1.4 million, and $1.5 million, respectively. Our proportionate share of assets, liabilities and net income relating to the oil and natural gas partnerships is included in our consolidated financial statements.

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Effects of Inflation

The effect of inflation in the oil and natural gas industry is primarily driven by the prices for oil, NGLs, and natural gas. Increases in these prices increase the demand for our contract drilling rigs and services. This increase in demand in turn affects the dayrates we can obtain for our contract drilling services. Over the last several years, natural gas, NGLs, and oil prices have been more volatile, and during periods of higher demand for our drilling rigs we have experienced increases in labor costs as well as the costs of services to support our drilling rigs. Historically, during this same period, when oil, NGLs, and natural gas prices did decline, labor rates did not come back down to the levels existing before the increases. If natural gas prices increase substantially for a long period, shortages in support equipment (such as drill pipe, third party services, and qualified labor) will result in additional increases in our material and labor costs. Increases in dayrates for drilling rigs also increase the cost of our oil and natural gas properties. How inflation will affect us in the future will depend on additional increases, if any, realized in our drilling rig rates, the prices we receive for our oil, NGLs, and natural gas, and the rates we receive for gathering and processing natural gas.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements with unconsolidated entities to enhance liquidity and capital resource positions, or for any other purpose. However, as is customary in the oil and gas industry, we are subject to various contractual commitments.

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Results of Operations

2012 versus 2011

Following is a comparison of selected operating and financial data:

	2012	2011	Percent Change [1]
Total operating revenue	$1,315,123,000	$1,207,503,000	9 %
Net income	$23,176,000	$195,867,000	(88)%
Contract Drilling:			
Revenue	$529,719,000	$484,651,000	9 %
Operating costs excluding depreciation	$289,524,000	$269,899,000	7 %
Percentage of revenue from daywork contracts	100 %	100 %	
Average number of drilling rigs in use	73.9	76.1	(3)%
Average dayrate on daywork contracts	$19,949	$18,842	6 %
Depreciation	$81,007,000	$79,667,000	2 %
Oil and Natural Gas:			
Revenue [2]	$567,944,000	$514,614,000	10 %
Operating costs excluding depreciation, depletion, amortization, and impairment	$150,212,000	$131,271,000	14 %
Average oil price (Bbl)	$92.60	$87.18	6 %
Average NGL price (Bbl)	$31.58	$43.64	(28)%
Average natural gas price (Mcf)	$3.37	$4.26	(21)%
Oil production (Bbl)	3,279,000	2,511,000	31 %
NGLs production (Bbl)	2,796,000	2,239,000	25 %
Natural gas production (Mcf)	48,930,000	44,104,000	11 %
Depreciation, depletion and amortization rate (Boe)	$14.70	$15.06	(2)%
Depreciation, depletion, and amortization	$211,347,000	$183,350,000	15 %
Impairment of oil and natural gas properties	$283,606,000	$—	NM
Mid-Stream Operations:			
Revenue	$217,460,000	$208,238,000	4 %
Operating costs excluding depreciation, amortization, and impairment	$187,292,000	$174,859,000	7 %
Depreciation, amortization, and impairment	$24,388,000	$16,101,000	51 %
Gas gathered—MMBtu/day	288,799	215,805	34 %
Gas processed—MMBtu/day	165,511	116,161	42 %
Gas liquids sold—gallons/day	542,578	412,064	32 %
General and administrative expense	$33,086,000	$30,055,000	10 %
Other income (expense): [2]			
Interest expense, net	$(14,137,000)	$(4,167,000)	NM
Gain/(loss) on derivatives not designated as hedges and hedge ineffectiveness	$(1,243,000)	$1,702,000	(173)%
Other	$121,000	$(834,000)	115 %
Income tax expense	$16,226,000	$123,135,000	(87)%
Average interest rate	6.1 %	5.6 %	9 %
Average long-term debt outstanding	$495,830,000	$249,681,000	99 %

(1) NM – A percentage calculation is not meaningful due to a zero-value denominator or a percentage change greater than 200.

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(2) During the third quarter of 2012, we made the decision to prospectively use mark-to-market accounting for our economic hedges. Previously, we reported all realized and unrealized hedging gains (losses) in oil and natural gas revenues and now we reflect gains (losses) on non-designated hedges and the ineffectiveness from cash flow hedges along with other revenue items in other income (expense) below income from operations. Prior year amounts have been reclassified to conform to current year presentation.

Contract Drilling

Drilling revenues increased $45.1 million or 9% in 2012 as compared to 2011 primarily due to $22.6 million in termination fees during 2012 for eight drilling rigs that were under long-term contracts but were terminated early by the operator and a 6% increase in the average dayrate, somewhat offset by a 3% decrease in rigs utilized. Average drilling rig utilization decreased from 76.1 drilling rigs in 2011 to 73.9 drilling rigs in 2012.

Drilling operating costs increased $19.6 million or 7% in 2012 compared to 2011 due largely to increased personnel costs and to a lesser extent for repair and maintenance costs. The increased personnel cost was due to an increase in compensation for Rocky Mountain personnel in the first quarter of 2012 to keep qualified labor. Contract drilling depreciation increased $1.3 million or 2% primarily due to increased capital expenditures associated with the construction of new drilling rigs and for upgrades to existing drilling rigs in our fleet.

Oil and Natural Gas

Oil and natural gas revenues increased $53.3 million or 10% in 2012 as compared to 2011 primarily due to an increase in equivalent production volumes of 18% and an increase in oil prices partially offset by decreases in prices for NGLs and natural gas. Average oil prices between the comparative years increased 6% to $92.60 per barrel while NGLs and natural gas prices decreased 28% to $31.58 per barrel and 21% to $3.37 per Mcf, respectively. In 2012, as compared to 2011, oil production increased 31%, NGLs production increased 25%, and natural gas production increased 11%. Production increased from our drilling program and primarily from wells acquired from Noble.

Oil and natural gas operating costs increased $18.9 million or 14% between the comparative years of 2012 and 2011 due to increased well servicing costs, higher saltwater disposal fees, and higher gross production taxes due to higher revenue in 2012. Lease operating expenses per Boe decreased 2% to $6.66.

Depreciation, depletion, and amortization (“DD&A”) increased $28.0 million or 15% primarily due to an 18% increase in equivalent production slightly offset by a 2% decrease in our DD&A rate. The decrease in our DD&A rate resulted primarily from a reduction to the full cost pool from proceeds associated with the divestitures completed during the third quarter of 2012 and the non-cash ceiling test write-down of $115.9 million pre-tax ($72.1 million, net of tax) that occurred during the second quarter of 2012. Our DD&A expense on our oil and natural gas properties is calculated each quarter utilizing period end reserve quantities adjusted for current period production.

During the fourth quarter of 2012, we recorded a non-cash ceiling test write down of $167.7 million pre-tax ($104.4 million, net of tax). If there are further declines in the 12-month average prices, including the discounted value of our commodity hedges, we may be required to record a write-down in future periods.

Mid-Stream

Our mid-stream revenues increased $9.2 million or 4% in 2012 as compared to 2011 primarily due to higher NGLs volumes offset by a decrease in price. Gas processing volumes per day increased 42% between the comparative years and NGLs sold per day increased 32% between the comparative periods. The increase in volumes processed per day is primarily attributable to the volumes added from new wells connected to existing systems and increased capacity of processing facilities. NGLs sold volumes per day increased due to an increase in volumes processed and upgrades to several of our processing facilities . Gas gathering volumes per day increased 34% primarily from new well connections. The average price for NGLs sold decreased 27%.

Operating costs increased $12.4 million or 7% in 2012 compared to 2011 primarily due to a 42% increase in per day gas volumes purchased offset by a 30% decrease in prices paid for natural gas purchased. Depreciation, amortization, and impairment increased $8.3 million or 51% primarily due to the $1.2 million write-down of the carrying value of our Erick system and increased assets placed into service throughout 2012.

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General and Administrative

General and administrative expenses increased $3.0 million or 10% in 2012 compared to 2011 primarily due to increases in employee costs.

Other Income (Expense)

Interest expense, net of capitalized interest, increased $10.0 million between the comparative years of 2012 and 2011. We capitalized interest based on the net book value associated with undeveloped leasehold not being amortized, the construction of additional drilling rigs and the construction of gas gathering systems. Our average interest rate increased from 5.6% to 6.1% and our average debt outstanding was $246.1 million higher in 2012 as compared to 2011 due to the issuance of $400.0 million of senior subordinated notes during the third quarter of 2012 to partially fund the Noble acquisition in the oil and natural gas segment.

Income Tax Expense

Income tax expense decreased $106.9 million or 87% in 2012 compared to 2011 primarily due to decreased income. Our effective tax rate was 41.2% for 2012 and 38.6% for 2011. Current income tax expense was $0.7 million in 2012 compared to a current tax benefit of $2.4 million for 2011. We paid $5.1 million in income taxes during 2012.

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2011 versus 2010

	2011	2010	Percent Change [1]
Total operating revenue	$1,207,503,000	$870,671,000	39 %
Net income	$195,867,000	$146,484,000	34 %
Contract Drilling:			
Revenue	$484,651,000	$316,384,000	53 %
Operating costs excluding depreciation	$269,899,000	$186,813,000	44 %
Percentage of revenue from daywork contracts	100 %	100 %	
Average number of drilling rigs in use	76.1	61.4	24 %
Average dayrate on daywork contracts	$18,842	$15,478	22 %
Depreciation	$79,667,000	$69,970,000	14 %
Oil and Natural Gas:			
Revenue [2]	$514,614,000	$399,771,000	29 %
Operating costs excluding depreciation, depletion, and amortization	$131,271,000	$105,365,000	25 %
Average oil price (Bbl)	$87.18	$69.52	25 %
Average NGL price (Bbl)	$43.64	$37.04	18 %
Average natural gas price (Mcf)	$4.26	$5.62	(24)%
Oil production (Bbl)	2,511,000	1,521,000	65 %
NGLs production (Bbl)	2,239,000	1,549,000	45 %
Natural gas production (Mcf)	44,104,000	40,756,000	8 %
Depreciation, depletion and amortization rate (Boe)	$15.06	$11.94	26 %
Depreciation, depletion, and amortization	$183,350,000	$118,793,000	54 %
Mid-Stream Operations:			
Revenue	$208,238,000	$154,516,000	35 %
Operating costs excluding depreciation and amortization	$174,859,000	$122,146,000	43 %
Depreciation and amortization	$16,101,000	$15,385,000	5 %
Gas gathered—MMBtu/day	215,805	183,867	17 %
Gas processed—MMBtu/day	116,161	82,175	41 %
Gas liquids sold—gallons/day	412,064	271,360	52 %
General and administrative expense	$30,055,000	$26,152,000	15 %
Other income (expense): [2]			
Interest expense, net	$(4,167,000)	$—	NM
Gain/(loss) on derivatives not designated as hedges and hedge ineffectiveness	$1,702,000	$1,036,000	64 %
Other income	$(834,000)	$10,138,000	(108)%
Income tax expense	$123,135,000	$90,737,000	36 %
Average interest rate	5.6 %	3.5 %	60 %
Average long-term debt outstanding	$249,681,000	$94,873,000	163 %

(1) NM – A percentage calculation is not meaningful due to a zero-value denominator or a percentage change greater than 200.

(2) During the third quarter of 2012, we made the decision to prospectively use mark-to-market accounting for our economic hedges. Previously, we reported all realized and unrealized hedging gains (losses) in oil and natural gas revenues and now we reflect gains (losses) on non-designated hedges and the ineffectiveness from cash flow hedges along with other revenue items in other income (expense) below income from operations. Prior year amounts have been reclassified to conform to current year presentation.

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Contract Drilling

Drilling revenues increased $168.3 million or 53% in 2011 versus 2010 primarily due to a 24% increase in the average number of drilling rigs in use during 2011 compared to 2010 and a 22% higher average dayrate in 2011 compared to 2010. Average drilling rig utilization increased from 61.4 drilling rigs in 2010 to 76.1 drilling rigs in 2011. Oil and NGLs prices improved in 2011 compared to 2010, creating increased demand for drilling rigs.

Drilling operating costs increased $83.1 million or 44% between the comparative years of 2011 and 2010 primarily due to increased utilization and increased direct cost due to higher personnel cost. Due to an increase in activity over last year's levels, competition to keep qualified labor has increased. Starting in the third quarter 2010, we increased compensation for drilling personnel in Oklahoma, Texas and Louisiana and again at the end of the first quarter 2011 for drilling personnel in all divisions. Contract drilling depreciation increased $9.7 million or 14% primarily due to increased utilization and from capital expenditures associated with the construction of new drilling rigs and for upgrades to existing drilling rigs in our fleet.

Oil and Natural Gas

Oil and natural gas revenues increased $114.8 million or 29% in 2011 as compared to 2010 primarily due to an increase in equivalent production volumes of 23% and an increase in oil and NGLs prices partially offset by decreases in prices for natural gas. Average oil and NGLs prices between the comparative years increased 25% to $87.18 per barrel and 18% to $43.64 per barrel, respectively, while natural gas prices decreased 24% to $4.26 per Mcf. In 2011, as compared to 2010, oil production increased 65%, NGLs production increased 45% and natural gas production increased 8%. Production increased from our drilling program and from wells acquired over the last twelve months while gas production for 2010 was negatively impacted by an unexpected shut-in of some of our production from operational issues experienced at a third party facility that processes our Segno field production and production growth was hampered by the lack of availability of fracing services to complete wells.

Oil and natural gas operating costs increased $25.9 million or 25% between the comparative years of 2011 and 2010 due to increases in lease operating expenses from increased well servicing costs and higher saltwater disposal fees and higher gross production taxes due to higher revenue from higher oil prices and increased production between years partially offset by refunds of production taxes attributable to high-cost gas wells received during the third quarter of 2011. Lease operating expenses per Boe increased 1% to $6.79.

DD&A increased $64.6 million or 54% primarily due to a 26% increase in our DD&A rate and a 23% increase in equivalent production. The increase in our DD&A rate in 2011 compared to 2010 resulted primarily from increased net book value from new reserves added throughout 2010 and 2011. Our DD&A expense on our oil and natural gas properties is calculated each quarter utilizing period end reserve quantities adjusted for current period production.

Mid-Stream

Our mid-stream revenues increased $53.7 million or 35% in 2011 as compared to 2010 primarily due to higher NGLs volumes and prices. The average price for NGLs sold increased 12%. Gas processing volumes per day increased 41% between the comparative years and NGLs sold per day increased 52% between the comparative periods. The increase in volumes processed per day is primarily attributable to the volumes added from new wells connected to existing systems and increased capacity of processing facilities. NGLs sold volumes per day increased due to an increase in volumes processed and upgrades to several of our processing facilities. Gas gathering volumes per day increased 17% primarily from new well connections.

Operating costs increased $52.7 million or 43% in 2011 compared to 2010 primarily due to a 11% increase in prices paid for natural gas purchased and a 38% increase in gas purchased. Depreciation and amortization increased $0.7 million, or 5%. For 2011, we increased well connections over 2010 due to increased drilling activity by operators in the areas of our existing gathering systems along with the benefit of the additional processing capacity from the Hemphill facility completed during the fourth quarter of 2010.

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General and Administrative

General and administrative expenses increased $3.9 million or 15% in 2011 compared to 2010 primarily due to increases in employee costs.

Other Income (Expense)

Interest expense, net of capitalized interest, increased $4.2 million between the comparative years of 2011 and 2010. We capitalized interest based on the net book value associated with undeveloped leasehold not being amortized, the construction of additional drilling rigs and the construction of gas gathering systems. Our average interest rate increased by 60% primarily due to the issuance of $250.0 million of Senior Subordinated Notes during the second quarter of 2011 and our average debt outstanding was $154.8 million higher in 2011 as compared to 2010 due to the drilling of developmental wells and construction of new rigs in 2011.

Income Tax Expense

Income tax expense increased $32.4 million or 36% in 2011 compared to 2010 primarily due to increased income. Our effective tax rate was 38.6% for 2011 and 38.3% for 2010. Current income tax benefit for 2011 was $2.4 million due to a larger than expected net operating loss carryback recognized in the third quarter of 2011 compared with $9.9 million of total current income tax benefit for 2010 due to expected bonus depreciation for 2010. We paid $0.7 million in income taxes during 2011.

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Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Our operations are exposed to market risks primarily as a result of changes in the prices for natural gas and oil and interest rates.

Commodity Price Risk. Our major market risk exposure is in the prices we receive for our oil, NGLs, and natural gas production. Those prices are primarily driven by the prevailing worldwide price for crude oil and market prices applicable to our natural gas production. Historically, these prices have fluctuated and we expect they will continue to do so. The price of oil, NGLs, and natural gas also affects both the demand for our drilling rigs and the amount we can charge for the use of our drilling rigs. Based on our 2012 production, a $0.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $386,000 per month ($4.6 million annualized) change in our pre-tax cash flow. A $1.00 per barrel change in our oil price would have a $259,000 per month ($3.1 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGLs prices would have a $220,000 per month ($2.6 million annualized) change in our pre-tax cash flow.

We use hedging transactions to manage the risk associated with price volatility. Our decisions regarding the amount and prices at which we choose to hedge certain of our products is based, in part, on our view of current and future market conditions. The transactions we use include financial price swaps under which we will receive a fixed price for our production and pay a variable market price to the contract counterparty. We do not hold or issue derivative instruments for speculative trading purposes.

At December 31, 2012, the following designated cash flow hedges were outstanding:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Jan’13 – Dec’13	Natural gas – swap	60,000 MMBtu/day	$3.56	IF – NYMEX (HH)
Jan’13 – Dec’13	Crude oil – swap	5,500 Bbl/day	$99.71	WTI – NYMEX
Jan’13 – Dec’13	Natural gas – collar	20,000 MMBtu/day	$3.25-3.72	IF – NYMEX (HH)

At December 31, 2012, the following non-designated hedges were outstanding:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Jan’13 – Dec’13	Natural gas – swap	20,000 MMBtu/day	$3.94	IF – NYMEX (HH)
Jan’13 – Dec’13	Crude oil – swap	1,000 Bbl/day	$90.63	WTI – NYMEX
Jan’14 – Dec’14	Crude oil – swap	1,000 Bbl/day	$90.60	WTI – NYMEX

Subsequent to December 31, 2012, the following non-designated hedges were entered into:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Feb’13 – Dec’13	Crude oil – swap	2,000 Bbl/day	$96.58	WTI – NYMEX
Jan’14 – Dec’14	Crude oil – swap	1,000 Bbl/day	$92.20	WTI – NYMEX
Jan’14 – Dec’14	Crude oil – collar	2,000 Bbl/day	$90.00-95.00	WTI – NYMEX

Interest Rate Risk. Our interest rate exposure relates to our long-term debt under our credit agreement and the Notes. The credit agreement, at our election bears interest at variable rates based on the Prime Rate or the LIBOR Rate. At our election, borrowings under our credit agreement may be fixed at the LIBOR Rate for periods of up to 180 days. Under our Notes, we pay a fixed rate of interest of 6.625% per year (payable semi-annually in arrears on May 15 and November 15 of each year).

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Item 8. Financial Statements and Supplementary Data

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Unit Corporation and Subsidiaries

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Management's Report on Internal Control over Financial Reporting

Management of the company is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined in Rules 13a-15(f) or 15d-15(f) promulgated under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, the company's principal executive and principal financial officers and effected by the company's board of directors, management and other personnel, 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 and includes those policies and procedures that:

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company;
- 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
- 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. Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

The company's management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2012. In making this assessment, the company's management used the criteria set forth in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on their assessment, the company's management concluded that, as of December 31, 2012, the company's internal control over financial reporting was effective based on those criteria.

The effectiveness of the company'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.

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Report of Independent Registered Public Accounting Firm

To Board of Directors and Shareholders of Unit Corporation:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, changes in shareholders' equity, and cash flows present fairly, in all material respects, the financial position of Unit 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 index appearing under item 15(a)(2), presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. 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 the accompanying Management's Report on Internal Control Over Financial Reporting. 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

Tulsa, Oklahoma

February 26, 2013

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UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
	2012	2011
	(In thousands except share and par value amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$974	$835
Accounts receivable (less allowance for doubtful accounts of $5,343 both at December 31, 2012 and 2011)	146,046	165,276
Materials and supplies	8,563	8,202
Current derivative asset (Note 13)	16,552	31,938
Current income tax receivable	901	—
Current deferred tax asset (Note 8)	8,765	10,936
Prepaid expenses and other	13,843	11,278
Total current assets	195,644	228,465
Property and equipment:		
Drilling equipment	1,478,645	1,423,570
Oil and natural gas properties, on the full cost method:		
Proved properties	3,822,381	3,302,032
Undeveloped leasehold not being amortized	521,659	185,632
Gas gathering and processing equipment	461,629	278,919
Transportation equipment	37,728	34,118
Other	62,840	37,544
	6,384,882	5,261,815
Less accumulated depreciation, depletion, amortization and impairment	2,907,660	2,319,484
Net property and equipment	3,477,222	2,942,331
Debt issuance cost	13,432	5,671
Goodwill (Note 2)	62,808	62,808
Other intangible assets, net	680	1,855
Non-current derivative asset (Note 13)	—	4,514
Other assets	11,334	11,076
Total assets	$3,761,120	$3,256,720

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UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS - (Continued)

	As of December 31, 2012	2011
	(In thousands except share and par value amounts)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$138,811	$143,311
Accrued liabilities (Note 5)	53,162	51,733
Income taxes payable	—	781
Contract advances	936	2,055
Current derivative liabilities (Note 13)	1,948	2,657
Current portion of other long-term liabilities (Note 6)	12,282	12,213
Total current liabilities	207,139	212,750
Long-term debt (Note 6)	716,359	300,000
Non-current derivative liabilities (Note 13)	562	—
Other long-term liabilities (Note 6)	166,983	113,830
Deferred income taxes (Note 8)	695,776	683,123
Commitments and contingencies (Note 15)	—	—
Shareholders' equity:		
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	—	—
Common stock, $0.20 par value, 175,000,000 shares authorized, 48,581,948 and 48,151,442 shares issued as of December 31, 2012 and 2011, respectively	9,594	9,541
Capital in excess of par value	423,603	408,109
Accumulated other comprehensive income (net of tax of $4,892 and $11,961, respectively)	7,587	19,026
Retained earnings	1,533,517	1,510,341
Total shareholders' equity	1,974,301	1,947,017
Total liabilities and shareholders' equity	$3,761,120	$3,256,720

The accompanying notes are an integral part of the consolidated financial statements.

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UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2012	2011	2010
	(In thousands except per share amounts)		
Revenues:			
Contract drilling	$529,719	$484,651	$316,384
Oil and natural gas	567,944	514,614	399,771
Gas gathering and processing	217,460	208,238	154,516
Total revenues	1,315,123	1,207,503	870,671
Expenses:			
Contract drilling:			
Operating costs	289,524	269,899	186,813
Depreciation	81,007	79,667	69,970
Oil and natural gas:			
Operating costs	150,212	131,271	105,365
Depreciation, depletion, and amortization	211,347	183,350	118,793
Impairment of oil and natural gas properties (Note 2)	283,606	—	—
Gas gathering and processing:			
Operating costs	187,292	174,859	122,146
Depreciation, amortization, and impairment	24,388	16,101	15,385
General and administrative	33,086	30,055	26,152
Total expenses	1,260,462	885,202	644,624
Income from operations	54,661	322,301	226,047
Other income (expense):			
Interest, net	(14,137)	(4,167)	—
Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net	(1,243)	1,702	1,036
Other	121	(834)	10,138
Total other income (expense)	(15,259)	(3,299)	11,174
Income before income taxes	39,402	319,002	237,221
Income tax expense (benefit):			
Current	696	(2,416)	(9,935)
Deferred	15,530	125,551	100,672
Total income taxes	16,226	123,135	90,737
Net income	$23,176	$195,867	$146,484
Net income per common share:			
Basic	$0.48	$4.11	$3.10
Diluted	$0.48	$4.08	$3.09

The accompanying notes are an integral part of the consolidated financial statements.

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UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	For Years ended December 31,		
	2012	2011	2010
	(In thousands)		
Net income	$ 23,176	$ 195,867	$ 146,484
Other comprehensive income (loss), net of taxes:			
Change in value of derivative instruments used as cash flow hedges, net of tax of $12,094, $18,412, and $13,254	18,635	29,384	21,392
Reclassification - derivative settlements, net of tax of ($20,171), ($1,146), and ($19,987)	(31,682)	(1,819)	(32,268)
Ineffective portion of derivatives, net of tax of $1,008, ($1,061), and ($267)	1,608	(1,688)	(433)
Comprehensive income	$ 11,737	$ 221,744	$ 135,175

The accompanying notes are an integral part of the consolidated financial statements.

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UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
Year Ended December 31, 2010, 2011, and 2012

	Common Stock	Capital In Excess of Par Value	Accumulated Other Comprehensive Income	Retained Earnings	Total
	(In thousands except share amounts)				
Balances, January 1, 2010	$9,405	$383,957	$4,458	$1,167,990	$1,565,810
Comprehensive income (loss):					
Net income	—	—	—	146,484	146,484
Other comprehensive loss (net of tax of ($7,000))	—	—	(11,309)	—	(11,309)
Total comprehensive income					135,175
Activity in employee compensation plans (379,762 shares)	88	9,544	—	—	9,632
Balances, December 31, 2010	9,493	393,501	(6,851)	1,314,474	1,710,617
Comprehensive income:					
Net income	—	—	—	195,867	195,867
Other comprehensive income (net of tax of $16,205)	—	—	25,877	—	25,877
Total comprehensive income					221,744
Activity in employee compensation plans (241,011 shares)	48	14,608	—	—	14,656
Balances, December 31, 2011	9,541	408,109	19,026	1,510,341	1,947,017
Comprehensive income (loss):					
Net income	—	—	—	23,176	23,176
Other comprehensive loss (net of tax ($7,069))	—	—	(11,439)	—	(11,439)
Total comprehensive income					11,737
Activity in employee compensation plans (430,506 shares)	53	15,494	—	—	15,547
Balances, December 31, 2012	$9,594	$423,603	$7,587	$1,533,517	$1,974,301

The accompanying notes are an integral part of the consolidated financial statements.

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UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2012	2011	2010
	(In thousands)		
OPERATING ACTIVITIES:			
Net income	$23,176	$195,867	$146,484
Adjustments to reconcile net income (loss) to net cash provided (used) by operating activities:			
Depreciation, depletion, amortization, and impairment	319,021	280,451	205,124
Impairment of oil and natural gas properties (Note 2)	283,606	—	—
Unrealized (gain) loss on derivatives	1,243	(2,413)	(1,036)
(Gain) loss on disposition of assets	(253)	595	(9,687)
Deferred tax expense	15,530	125,551	100,672
Employee stock compensation plans	16,956	14,303	10,067
Bad debt expense	90	260	—
ARO liability accretion	4,615	3,838	2,937
Other, net	781	294	(69)
Changes in operating assets and liabilities increasing (decreasing) cash:			
Accounts receivable	13,994	(38,731)	(58,965)
Materials and supplies	(361)	(1,886)	598
Prepaid expenses and other	(3,466)	22,672	6,957
Accounts payable	10,187	(1,064)	(8,913)
Accrued liabilities	6,911	9,245	(3,555)
Contract advances	(1,119)	(527)	(542)
Net cash provided by operating activities	690,911	608,455	390,072
INVESTING ACTIVITIES:			
Capital expenditures	(762,381)	(728,551)	(484,080)
Producing property and other acquisitions	(598,485)	(50,013)	(92,229)
Proceeds from disposition of property and equipment	281,824	10,328	40,048
Net cash used in investing activities	(1,079,042)	(768,236)	(536,261)
FINANCING ACTIVITIES:			
Borrowings under line of credit	735,300	441,500	286,900
Payments under line of credit	(714,200)	(554,500)	(153,900)
Proceeds from issuance of senior subordinated notes, net of debt issuance costs and discount	386,274	243,950	—
Proceeds from exercise of stock options	215	679	149
Tax benefit from stock options	121	1,174	40
Increase (decrease) in book overdrafts (Note 2)	(19,440)	26,454	13,219
Net cash provided by financing activities	388,270	159,257	146,408
Net increase (decrease) in cash and cash equivalents	139	(524)	219
Cash and cash equivalents, beginning of year	835	1,359	1,140
Cash and cash equivalents, end of year	$974	$835	$1,359
Supplemental disclosure of cash flow information:			
Cash paid during the year for:			
Interest paid (net of capitalized)	$14,880	$3,470	$—
Income taxes	$5,116	$655	$3,143

Changes in accounts payable and accrued liabilities related to purchases of property, plant, and equipment	$(4,753)	$(28,036)	$(29,700)
Non-cash additions to oil and natural gas properties related to asset retirement obligations	$45,097	$23,345	$9,924

The accompanying notes are an integral part of the consolidated financial statements.

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UNIT CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 – ORGANIZATION

Unless the context clearly indicates otherwise, references in this report to “Unit”, “Company”, “we”, “our”, “us”, or like terms refer to Unit Corporation and its subsidiaries.

We are primarily engaged in the land contract drilling of natural gas and oil wells, the exploration, development, acquisition, and production of oil and natural gas properties, and the buying, selling, gathering, processing, and treating of natural gas. Our operations are located principally in the United States and are organized in the following three reporting segments: (1) Contract Drilling, (2) Oil and Natural Gas, and (3) Mid-Stream.

Contract Drilling. Our contract drilling business is conducted through Unit Drilling Company and its subsidiary Unit Texas Drilling L.L.C. Through these companies we drill onshore oil and natural gas wells for our own account as well as for a wide range of other oil and natural gas companies. Our drilling operations are mainly located in Oklahoma, Texas, Louisiana, Kansas, Wyoming, Colorado, Utah, Montana, and North Dakota.

Oil and Natural Gas. Carried out by our subsidiary, Unit Petroleum Company, we explore, develop, acquire, and produce oil and natural gas properties for our own account. Our producing oil and natural gas properties, undeveloped leaseholds, and related assets are located mainly in Oklahoma and Texas, and to a lesser extent, in Arkansas, Colorado, Kansas, Louisiana, Mississippi, Montana, New Mexico, North Dakota, Pennsylvania, Wyoming, and a small portion in Canada.

Historically, our contract drilling segment has experienced a greater demand for natural gas drilling as opposed to drilling for oil and NGLs. With the current weakened natural gas market, operators are focusing on drilling for oil and NGLs.

Mid-Stream. Carried out by our subsidiary, Superior Pipeline Company, L.L.C. and its subsidiaries, we buy, sell, gather, transport, process, and treat natural gas for our own account and for third parties. Mid-stream operations are performed in Oklahoma, Texas, Kansas, Pennsylvania, and West Virginia.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation. The consolidated financial statements include the accounts of Unit Corporation and its subsidiaries. Our investment in limited partnerships is accounted for on the proportionate consolidation method, whereby our share of the partnerships’ assets, liabilities, revenues, and expenses are included in the appropriate classification in the accompanying consolidated financial statements.

Certain amounts in the accompanying consolidated financial statements for prior periods have been reclassified to conform to current year presentation. Certain financial statement captions were expanded or combined with no impact to consolidated net income or shareholders' equity.

Accounting Estimates. The preparation of financial statements in conformity with generally accepted accounting principles (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Drilling Contracts. We recognize revenues and expenses generated from “daywork” drilling contracts as the services are performed, since we do not bear the risk of completion of the well. Under “footage” and “turnkey” contracts, we bear the risk of completion of the well; therefore, revenues and expenses are recognized when the well is substantially completed. Under this method, substantial completion is determined when the well bore reaches the negotiated depth as stated in the contract. The entire amount of a loss, if any, is recorded when the loss is determinable. The costs of uncompleted drilling contracts include expenses incurred to date on “footage” or “turnkey” contracts, which are still in process at the end of the period, and are included in other current assets. Typically, any one of these three types of contracts can be used for the drilling of one well which can take from 20 to 90 days. At December 31, 2012, substantially all of our contracts were daywork contracts of which 27 were multi-well and had durations which ranged from 6 months to 3 years. These longer term contracts may contain a fixed

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UNIT CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

rate for the duration of the contract or provide for the periodic renegotiation of the rate within a specific range from the existing rate.

Cash Equivalents and Book Overdrafts. We include as cash equivalents all investments with maturities at date of purchase of three months or less which are readily convertible into known amounts of cash. Book overdrafts are checks that have been issued before the end of the period, but not presented to our bank for payment before the end of the period. At December 31, 2012 and 2011, book overdrafts were $7.0 million and $26.5 million, respectively, and included in accounts payable.

Accounts Receivable. Accounts receivable are carried on a gross basis, with no discounting, less an allowance for doubtful accounts. We estimate the allowance for doubtful accounts based on existing economic conditions, the financial condition of our customers, and the amount and age of past due accounts. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been unsuccessful.

Financial Instruments and Concentrations of Credit Risk and Non-performance Risk. Financial instruments, which potentially subject us to concentrations of credit risk, consist primarily of trade receivables with a variety of oil and natural gas companies. We do not generally require collateral related to receivables. Our credit risk is considered to be limited due to the large number of customers comprising our customer base. Below are the third-party customers that accounted for more than 10% of our segment’s revenues:

	2012		2011		2010	
Drilling:						
QEP Resources, Inc.	15	%	22	%	28	%
Kodiak Oil and Gas Corp.	10	%	6	%	5	%
Oil and Natural Gas:						
Valero Energy Corporation	26	%	18	%	7	%
Sunoco Partners Marketing	8	%	10	%	8	%
Mid-Stream:						
ONEOK	54	%	54	%	53	%
Gavilon, LLC	10	%	19	%	12	%
ConocoPhillips	4	%	7	%	12	%

We had a concentration of cash of $40.4 million and $31.1 million at December 31, 2012 and 2011, respectively with one bank.

The use of derivative transactions also involves the risk that the counterparties will be unable to meet the financial terms of the transactions. We considered this non-performance risk with regard to our counterparties and our own non-performance risk in our derivative valuation at December 31, 2012 and determined there was no material risk at that time. At December 31, 2012, the fair values of the net assets (liabilities) we had with each of the counterparties with respect to all of our commodity derivative transactions are listed in the table below:

	December 31, 2012 (In millions)
Comerica Bank	$ 8.1
Canadian Imperial Bank of Commerce	2.9
Bank of Montreal	2.6
BBVA Compass Bank	1.4

Bank of America, N.A.	(1.0)
Total assets (liabilities)	$ 14.0

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Property and Equipment. Drilling equipment, natural gas gathering and processing equipment, transportation equipment, and other property and equipment are carried at cost. Renewals and improvements are capitalized while repairs and maintenance are expensed. Depreciation of drilling equipment is recorded using the units-of-production method based on estimated useful lives starting at 15 years , including a minimum provision of 20% of the active rate when the equipment is idle. We use the composite method of depreciation for drill pipe and collars and calculate the depreciation by footage actually drilled compared to total estimated remaining footage. Depreciation of other property and equipment is computed using the straight-line method over the estimated useful lives of the assets ranging from 3 to 15 years.

Realization of the carrying value of property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset including disposal value if any, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. An estimate of fair value is based on the best information available, including prices for similar assets. Changes in such estimates could cause us to reduce the carrying value of property and equipment. In December 2012, our mid-stream segment had a $1.2 million write down of our Erick system. There was no volume from the wells connected to this system, the compressor and related surface equipment have been removed from this location and there is no future activity anticipated from this gathering system. No significant impairments were recorded in 2011 or 2010.

When property and equipment components are disposed of, the cost and the related accumulated depreciation are removed from the accounts and any resulting gain or loss is generally reflected in operations. For dispositions of drill pipe and drill collars, an average cost for the appropriate feet of drill pipe and drill collars is removed from the asset account and charged to accumulated depreciation and proceeds, if any, are credited to accumulated depreciation.

We record an asset and a liability equal to the present value of the expected future asset retirement obligation (ARO) associated with our oil and gas properties. The ARO asset is depreciated in a manner consistent with the depreciation of the underlying physical asset. We measure changes in the liability due to passage of time by accreting an interest charge. This amount is recognized as an increase in the carrying amount of the liability and as a corresponding accretion expense.

Goodwill. Goodwill represents the excess of the cost of acquisitions over the fair value of the net assets acquired. Goodwill is not amortized, but an impairment test is performed at least annually to determine whether the fair value has decreased and is performed additionally when events indicate an impairment may have occurred. Goodwill is all related to our contract drilling segment, and accordingly, the impairment test is generally based on the estimated discounted future net cash flows of our drilling segment, utilizing discount rates and other factors in determining the fair value of our drilling segment. Inputs in our estimated discounted future net cash flows include rig utilization, day rates, gross margin percentages, and terminal value (these are all considered level 3 inputs). No goodwill impairment was recorded for the years ended December 31, 2012, 2011, or 2010. There were no additions to goodwill in 2012, 2011, or 2010. Goodwill of $4.8 million is deductible for tax purposes.

Intangible Assets. Intangible assets are capitalized and amortized over the estimated period benefited. Such amounts are reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. No intangible asset impairment was recorded for the years ended December 31, 2012, 2011 or 2010. Amortization of $1.2 million, $1.2 million and $2.6 million was recorded in 2012, 2011, and 2010, respectively. Accumulated amortization for 2012 and 2011 was $17.3 million and $16.1 million, respectively. Amortization of $0.7 million is expected to be recorded in 2013.

Oil and Natural Gas Operations. We account for our oil and natural gas exploration and development activities using the full cost method of accounting prescribed by the SEC. Accordingly, all productive and non-productive costs incurred in connection with the acquisition, exploration and development of our oil and natural gas reserves, including directly related overhead costs and related asset retirement costs, are capitalized and amortized on a units-of-production method based on proved oil and natural gas reserves. Directly related overhead costs of $17.6 million, $15.6 million, and $13.4 million were capitalized in 2012, 2011, and 2010, respectively. Independent petroleum engineers annually audit our internal evaluation of our reserves. The average rates used for depreciation, depletion, and amortization (DD&A) were $14.70, $15.06, and $11.94 per Boe in 2012, 2011, and 2010, respectively. The calculation of DD&A includes estimated future expenditures to be incurred in developing proved reserves and estimated dismantlement and abandonment costs, net of estimated salvage values. Our undeveloped leasehold properties totaling $521.7 million are excluded from the DD&A calculation.

No gains or losses are recognized on the sale, conveyance or other disposition of oil and natural gas properties unless a significant reserve amount to our total reserves is involved.

Revenue from the sale of oil and natural gas is recognized when title passes, net of royalties.

Under the full cost rules, at the end of each quarter, we review the carrying value of our oil and natural gas properties. The full cost ceiling is based principally on the estimated future discounted net cash flows from our oil and natural gas properties discounted at 10%. We use the unweighted arithmetic average of the commodity prices existing on the first day of each of the 12 months before the end of the reporting period to calculate discounted future revenues, unless prices were otherwise determined under contractual arrangements. In the event the unamortized cost of oil and natural gas properties being amortized exceeds the full cost ceiling, as defined by the SEC, the excess is charged to expense in the period during which such excess occurs. Once incurred, a write-down of oil and natural gas properties is not reversible.

At December 31, 2010 and December 31, 2011, using the existing 12-month average commodity prices, including the discounted value of our commodity hedges, we were not required to record a ceiling test write-down.

For the quarter ended June 30, 2012, the 12-month average commodity prices, including the discounted value of our cash flow hedges, decreased significantly, resulting in a non-cash ceiling test write down of $115.9 million pre-tax ($72.1 million, net of tax). Our qualifying cash flow hedges used in the ceiling test determination at June 30, 2012, consisted of swaps and collars, covering production of 2.9 MMBoe in 2012 and 4.5 MMBoe in 2013. The effect of those hedges on the June 30, 2012 ceiling test was a $32.5 million pre-tax increase in the discounted net cash flows of our oil and natural gas properties.

For the quarter ended December 31, 2012, the 12-month average commodity prices, including the discounted value of our cash flow hedges, decreased further, resulting in an additional non-cash ceiling test write down of $167.7 million pre-tax ($104.4 million, net of tax). Our qualifying cash flow hedges used in the ceiling test determination at December 31, 2012, consisted of swaps and collars covering 6.9 MMBoe in 2013. The effect of those hedges on the December 31, 2012 ceiling test was a $29.8 million pre-tax increase in the discounted net cash flows of our oil and natural gas properties. Our oil and natural gas hedging is discussed in Note 13 of the Notes to our Consolidated Financial Statements.

If there are further declines in the 12-month average prices, including the discounted value of our cash flow hedges, we may be required to record a write-down in future periods.

Our contract drilling segment provides drilling services for our exploration and production segment. Depending on their timing some of the drilling services performed on our properties are also deemed to be associated with the acquisition of an ownership interest in the property. Revenues and expenses for such services are eliminated in our income statement, with any profit recognized as a reduction in our investment in our oil and natural gas properties. The contracts for these services are issued under the same conditions and rates as the contracts entered into with unrelated third parties. We eliminated revenue of $49.6 million, $52.2 million, and $40.1 million for 2012, 2011, and 2010, respectively from our contract drilling segment and eliminated the associated operating expense of $34.1 million, $32.6 million, and $31.0 million during 2012, 2011, and 2010, respectively, yielding $15.5 million, $19.6 million, and $9.1 million during 2012, 2011, and 2010, respectively, as a reduction to the carrying value of our oil and natural gas properties.

Gas Gathering and Processing Revenue. Our gathering and processing segment recognizes revenue from the gathering and processing of natural gas and NGLs in the period the service is provided based on contractual terms.

Insurance. We are self-insured for certain losses relating to workers' compensation, control of well and employee medical benefits. Insured policies for other coverage contain deductibles or retentions per occurrence that range from $50,000 to $1.5 million. We have purchased stop-loss coverage in order to limit, to the extent feasible, per occurrence and aggregate exposure to certain types of claims. However, there is no assurance that the insurance coverage will adequately protect us against liability from all potential consequences. We have elected to use an ERISA governed occupational injury benefit plan to cover all Texas drilling operations in lieu of covering them under Texas Workers' Compensation. If insurance coverage becomes more expensive, we may choose to self-insure, decrease our limits, raise our deductibles or any combination of these rather than pay higher premiums.

Hedging Activities. All derivatives are recognized on the balance sheet and measured at fair value. Derivatives that are designated as a cash flow hedge are measured by the effectiveness of the hedge, or the degree that the gain (loss) for the hedging instrument offsets the loss (gain) on the hedged item, at each reporting period. The effective portion of the gain (loss) on the derivative instrument is recognized in other comprehensive income as a component of equity and subsequently reclassified into earnings when the forecasted transaction affects earnings. The ineffective portion of a derivative's change in fair value is required to be recognized in earnings immediately. Derivatives that are not designated for hedge treatment are recorded at fair value with gains (losses) recognized in earnings in the period of change. In August 2012, we determined on a prospective basis, to enter into economic hedges without electing cash flow hedge accounting. Our current cash flow hedges (that existed before August 2012) will expire in December 2013.

We do not engage in derivative transactions for speculative purposes. We document our risk management strategy, and for cash flow hedges, we test the hedge effectiveness at the inception of and during the term of each hedge.

Limited Partnerships. Unit Petroleum Company is a general partner in 16 oil and natural gas limited partnerships sold privately and publicly. Some of our officers, directors, and employees own the interests in most of these partnerships. We share in each partnership's revenues and costs in accordance with formulas set out in each of the limited partnership agreement. The partnerships also reimburse us for certain administrative costs incurred on behalf of the partnerships.

Income Taxes. Measurement of current and deferred income tax liabilities and assets is based on provisions of enacted tax law; the effects of future changes in tax laws or rates are not included in the measurement. Valuation allowances are established where necessary to reduce deferred tax assets to the amount expected to be realized. Income tax expense is the tax payable for the year and the change during that year in deferred tax assets and liabilities.

The accounting for uncertainty in income taxes prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a return. Guidance is also provided on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. We have no unrecognized tax benefits and we do not expect any significant changes in unrecognized tax benefits in the next twelve months.

Natural Gas Balancing. We use the sales method for recording natural gas sales. This method allows for recognition of revenue, which may be more or less than its share of pro-rata production from certain wells. We estimate our December 31, 2012 balancing position to be approximately 5.1 Bcf on under-produced properties and approximately 4.6 Bcf on over-produced properties. We have recorded a receivable of $2.4 million on certain wells where we estimate that insufficient reserves are available for us to recover the under-production from future production volumes. We have also recorded a liability of $3.8 million on certain properties where we believe there are insufficient reserves available to allow the under-produced owners to recover their under-production from future production volumes. Our policy is to expense the pro-rata share of lease operating costs from all wells as incurred. Such expenses relating to the balancing position on wells in which we have imbalances are not material.

Employee and Director Stock Based Compensation. We recognize in our financial statements the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards. The amount of our equity compensation cost relating to employees directly involved in our oil and natural gas segment is capitalized to our oil and natural gas properties. Amounts not capitalized to our oil and natural gas properties are recognized in general and administrative expense and operating costs of our business segments. We utilize the Black-Scholes option pricing model to measure the fair value of stock options and stock appreciation rights (SARs). The value of our restricted stock grants is based on the closing stock price on the date of the grants.

Impact of Financial Accounting Pronouncements.

Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards (IFRS). In May 2011, the FASB issued ASU 2011-04 Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS. ASU 2011-4 is intended to improve the comparability of fair value measurements presented and disclosed in financial statements prepared in accordance with U.S. GAAP and IFRS. The amendments are of two types: (i) those that clarify the Board's intent about the application of existing fair value measurement and disclosure requirements and (ii) those that change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements. The update is effective for annual periods beginning after December 15, 2011. We are in the process of evaluating the impact, if any, the adoption of this update will have on our financial statements.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Presentation of Comprehensive Income. In June 2011, the FASB issued ASU 2011-05—Presentation of Comprehensive Income. This ASU amends the Codification to allow an entity the option to present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. ASU 2011-05 eliminates the option to present the components of other comprehensive income as part of the statement of changes in stockholders' equity. The amendments to the Codification in the ASU 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. We chose to present net income and comprehensive income as two consecutive statements in our financial statements.

In February 2013, the FASB issued ASU 2013-02 to address the presentation of comprehensive income related to ASU 2011-05. The standard requires that companies present either in a single note or parenthetically on the face of the financial statements, the effect of significant amounts reclassified from each component of accumulated other comprehensive income based on its source (e.g., the release due to cash flow hedges from interest rate contracts) and the income statement line items affected by the reclassification (e.g., interest income or interest expense). The amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2012. We are in the process of evaluating the option we will choose to present comprehensive income and the impact it will have on our financial statements.

Disclosures about Offsetting Assets and Liabilities. In January 2011, the FASB issued ASU 2011-11—Disclosures about Offsetting Assets and Liabilities. Unlike IFRS, U.S. GAAP allows companies the option to present net in their balance sheets derivatives that are subject to a legally enforceable netting arrangement with the same party where rights of set-off are only available in the event of default or bankruptcy. To address these differences between IFRS and U.S. GAAP, the FASB and the IASB (the Boards) issued an exposure draft that proposed new criteria for netting that were narrower than the current conditions currently in U.S. GAAP. Nevertheless, in response to feedback from their respective stakeholders, the Boards decided to retain their existing offsetting models. Instead, the Boards have issued common disclosure requirements related to offsetting arrangements to allow investors to better compare financial statements prepared in accordance with IFRS or U.S. GAAP. The amendments in this ASU 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. An entity is required to apply the amendments for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. An entity should provide the disclosures required by those amendments retrospectively for all comparative periods presented. We are in the process of evaluating the impact this will have on our financial statements.

NOTE 3 – ACQUISITIONS AND DIVESTITURES

On June 2, 2010, we completed an acquisition of oil and natural gas properties from certain unaffiliated parties in an effort to explore and develop more oil rich plays. The properties were purchased for approximately $73.7 million in cash, after post-closing adjustments. The purchase price allocation was $48.7 million for proved properties and $25.0 million for undeveloped leasehold not being amortized. The acquisition included approximately 45,000 net leasehold acres and 10 producing oil wells. This acquisition targeted the Marmaton horizontal oil play located mainly in Beaver County, Oklahoma.

On July 20, 2011, we acquired certain producing properties from an unaffiliated seller for approximately $12.3 million in cash, after post-closing adjustments, consisting of 30 operated wells and 59 non-operated well interests located in Beaver, Harper, and Ellis Counties,Oklahoma and Lipscomb County, Texas. The purchase price allocation was $8.4 million for proved properties and $3.9 million for acreage. The acquisition also included in excess of 12,000 net acres held by production available for future development.

On August 31, 2011, we acquired certain producing oil and gas properties for $30.5 million in cash, from an unaffiliated seller. Included in the acquisition were more than 500 wells located principally in the Oklahoma Arkoma Woodford and Hartshorne Coal plays along with other properties located throughout Oklahoma and Texas. The acquisition also included approximately 55,000 net acres of which 96% was held by production.

On September 17, 2012, we closed on the acquisition of certain oil and natural gas assets from Noble Energy, Inc. (Noble). After final closing adjustments, the acquisition included approximately 83,000 net acres primarily in the Granite Wash, Cleveland, and various other plays in western Oklahoma and the Texas Panhandle. The adjusted amount paid was $592.6 million.

As of April 1, 2012, the effective date of the Noble acquisition,the estimated proved reserves of the acquired properties were 44 million barrels of oil equivalent (MMBoe). The acquisition adds approximately 24,000 net acres to our Granite Wash core area in the Texas Panhandle with significant resource potential including approximately 600 horizontal drilling locations. The total acreage acquired in other plays in western Oklahoma and the Texas Panhandle was approximately 59,000 net acres and is characterized by high working interest and operatorship, 95% of which was held by production. We also received four gathering systems as part of the transaction and other miscellaneous assets.

The Noble acquisition is accounted for using the acquisition method under ASC 805, Business Combinations, which requires that the acquired assets and liabilities be recorded at their fair values as of the acquisition date. The following table summarizes the adjusted purchase price and the estimated values of assets acquired and liabilities assumed. It is based on information available to us at the time these consolidated financial statements were prepared. We believe these estimates are reasonable; however, the estimates are subject to change as additional information becomes available and is assessed by us (in thousands):

Adjusted Purchase Price	
Total consideration given	$592,627
Adjusted Allocation of Purchase Price	
Oil and natural gas properties included in the full cost pool:	
Proved oil and natural gas properties	$260,799
Undeveloped oil and natural gas properties	353,343
Total oil and natural gas properties included in the full cost pool (1)	614,142
Gas gathering and processing equipment and other	25,163
Asset retirement obligation	(46,678)
Fair value of net assets acquired	$592,627

(1) We used a discounted cash flow model and made 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.

Pro Forma Financial Information

The following unaudited pro forma financial information is presented to reflect the operations of the acquired assets as if the acquisition had been completed on January 1, 2011. The unaudited pro forma financial information was derived from the historical accounting records of the seller adjusted for estimated transaction costs, depreciation, depletion and amortization, ceiling test impact, general and administrative expenses, capitalized interest, and interest on the $400.0 million of bonds issued along with additional borrowings under our credit agreement to finance the acquisition. The unaudited pro forma financial information does not purport to be indicative of results of operations that would have occurred had the transaction occurred on the basis assumed above, nor is such information indicative of our expected future results of operations. The pro forma results of operations do not include any cost savings or other synergies that resulted, or may result, from the acquisition or any estimated costs that will be incurred to integrate these assets. Future results may vary significantly from the results reflected in this pro forma financial information because of future events and transactions, as well as other factors.

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	Twelve months ended December 31,	
	2012	2011
	(In thousands, except per share amounts)	
Pro forma:		
Revenues	$1,376,393	$1,336,227
Net income	$83,940	$229,272
Net income per common share:		
Basic	$1.75	$4.81
Diluted	$1.74	$4.78

From September 17, 2012, the date of the acquisition, through the end of the year, the portion of our revenues that were attributable to Noble were $21.4 million with a net loss of $0.8 million.

2012 Divestitures

We completed the following divestitures in 2012, all of which were accounted for as adjustments to the full cost pool with no gain or loss recognized:

•In September 2012, we sold our interest in certain Bakken properties (representing approximately 35% of our total acreage in the Bakken play). The proceeds, net of related expenses were $226.6 million.

•In September 2012, we sold certain oil and natural gas assets located in Brazos and Madison Counties, Texas, for approximately $44.1 million.

Other

In conjunction with the acquisition and divestitures completed in the third quarter 2012, we took the necessary steps to secure like-kind exchange tax treatment for the transactions under Section 1031 of the Internal Revenue Code.

NOTE 4 – EARNINGS PER SHARE

The following data shows the amounts used in computing earnings per share:

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the year ended December 31, 2012:			
Basic earnings per common share	23,176	47,909	0.48
Effect of dilutive stock options, restricted stock and SARs	—	245	—
Diluted earnings per common share	23,176	48,154	0.48
For the year ended December 31, 2011:			
Basic earnings per common share	195,867	47,658	4.11
Effect of dilutive stock options, restricted stock and SARs	—	293	(0.03)
Diluted earnings per common share	195,867	47,951	4.08
For the year ended December 31, 2010:			
Basic earnings per common share	146,484	47,278	3.10
Effect of dilutive stock options and restricted stock	—	176	(0.01)
Diluted earnings per common share	146,484	47,454	3.09

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

The following options and their average exercise prices were not included in the computation of diluted earnings per share because the option exercise prices were greater than the average market price of our common stock for the years ended December 31:

	2012	2011	2010
Options and SARs	250,901	105,000	222,901
Average exercise price	$52.72	$61.24	$52.59

NOTE 5 – ACCRUED LIABILITIES

Accrued liabilities consisted of the following as of December 31:

	2012	2011
	(In thousands)	
Employee costs	$24,632	$22,518
Lease operating expenses	10,903	7,346
Taxes	7,308	13,480
Interest payable	6,568	2,647
Hedge settlements	160	1,844
Other	3,591	3,898
Total accrued liabilities	$53,162	$51,733

NOTE 6 – LONG-TERM DEBT AND OTHER LONG-TERM LIABILITIES

Long-Term Debt

Long-term debt consisted of the following as of December 31:

	2012	2011
	(In thousands)	
Credit agreement with an average interest rates of 2.9% and 2.7% at December 31, 2012 and 2011, respectively	$71,100	$50,000
6.625% senior subordinated notes due 2021, net of unamortized discount of $4.7 million at December 31, 2012	645,259	250,000
Total long-term debt	$716,359	$300,000

Credit Agreement. On September 5, 2012, we amended our Senior Credit Agreement (credit agreement) scheduled to mature on September 13, 2016. The amount available to be borrowed is the lesser of the amount we elect (from time to time) as the commitment amount (amended to $500.0 million from $250.0 million) or the value of the borrowing base as determined by the lenders (amended to $800.0 million from $600.0 million), but in either event not to exceed the maximum credit agreement amount of $900.0 million (amended from $750.0 million). We are charged a commitment fee ranging from 0.375 to 0.50 of 1% on the amount available but not borrowed. The rate varies based on the amount borrowed as a percentage of the amount of the total borrowing base. In connection with this new amendment, we paid $1.5 million in origination, agency, syndication, and other related fees. We are amortizing these fees over the life of the credit agreement.

The amount of the borrowing base, which is subject to redetermination by the lenders on April 1st and October 1st of each year, is based primarily on a percentage of the discounted future value of our oil and natural gas reserves. We or the

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lenders may request a onetime special redetermination of the borrowing base between each scheduled redetermination. In addition, we may request a redetermination following the completion of an acquisition that meets the requirements set forth in the credit agreement.

At our election, any part of the outstanding debt under the credit agreement may be fixed at a London Interbank Offered Rate (LIBOR). LIBOR interest is computed as the sum of the LIBOR base for the applicable term plus 1.75% to 2.50% depending on the level of debt as a percentage of the borrowing base and is payable at the end of each term, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the Prime Rate, which cannot be less than LIBOR plus 1.00%. Interest is payable at the end of each month, and the principal may be repaid in whole or in part at anytime, without a premium or penalty. At December 31, 2012, we had $71.1 million of outstanding borrowings under our credit agreement.
We can use borrowings for financing general working capital requirements for (a) exploration, development, production and acquisition of oil and gas properties, (b) acquisitions and operation of mid-stream assets, (c) issuance of standby letters of credit, (d) contract drilling services, and (e) general corporate purposes.

The credit agreement prohibits, among other things:

- the payment of dividends (other than stock dividends) during any fiscal year in excess of 30% of our consolidated net income for the preceding fiscal year;
- the incurrence of additional debt with certain limited exceptions; and
- the creation or existence of mortgages or liens, other than those in the ordinary course of business, on any of our properties, except in favor of our lenders.

The credit agreement also requires that we have at the end of each quarter:

- a current ratio (as defined in the credit agreement) of not less than 1 to 1; and
- a leverage ratio of funded debt to consolidated EBITDA (as defined in the credit agreement) for the most recently ended rolling four fiscal quarters of no greater than 4 to 1.

As of December 31, 2012, we were in compliance with the covenants contained in the credit agreement.

6.625% Senior Subordinated Notes. On May 18, 2011, we completed the sale of $250.0 million aggregate principal amount of our 6.625% Senior Subordinated Notes due 2021 (the 2011 Notes). The Notes were issued at par and mature on May 15, 2021. We received net proceeds of approximately $244.0 million after deducting fees of approximately $6.0 million. Those fees are being amortized as deferred financing costs over the life of the Notes. We used the net proceeds to repay outstanding borrowings under our credit agreement, which was $220.3 million on May 18, 2011. The remaining proceeds were used for general working capital purposes.

On July 24, 2012, we completed the sale of $400.0 million aggregate principal amount of unregistered senior subordinated notes (the 2012 Notes) due May 15, 2021, which will bear interest at a rate of 6.625% per year. The 2012 Notes were sold at 98.75% of par plus accrued interest from May 15, 2012. We used the net proceeds from the offering to partially finance the acquisition of oil and natural gas properties from Noble. We incurred $8.7 million of fees that are being amortized as debt issuance cost over the life of the 2012 Notes.

On November 13, 2012, we registered with the SEC on Form S-4 an offer to exchange the 2012 Notes for additional notes with materially identical terms to our existing 2011 Notes, which were registered under the Securities Act. On January 7, 2013, the exchange of the 2012 Notes was completed. The notes issued in exchange for the 2012 Notes are now registered and treated as a single series of debt securities with the 2011 Notes, bringing the total to $650.0 million aggregate principal amount of 6.625% senior subordinated notes (the Notes). The interest is payable semi-annually (in arrears) on May 15 and November 15 of each year, and the Notes will mature on May 15, 2021

The Notes are guaranteed by our 100% owned domestic direct and indirect subsidiaries (the Guarantors). Unit, as the parent company, has no independent assets or operations. The guarantees registered under the registration statement are full and unconditional and joint and several, subject to certain automatic customary releases, including sale, disposition, or transfer of the capital stock or substantially all of the assets of a subsidiary guarantor, exercise of legal defeasance option or covenant defeasance option, and designation of a subsidiary guarantor as unrestricted in accordance with the Indenture. Any subsidiaries of Unit other than the Guarantors are minor. There are no significant restrictions on the ability of Unit to receive funds from its subsidiaries through dividends, loans, advances or otherwise.

The Notes are subject to an Indenture dated as of May 18, 2011, between us and Wilmington Trust, National Association (successor to Wilmington Trust FSB), as Trustee (the Trustee), as supplemented by the First Supplemental Indenture thereto dated as of May 18, 2011, between us, the Guarantors, and the Trustee, and as further supplemented by that the Second Supplemental Indenture thereto dated as of January 7, 2013, between us, the Guarantors and the Trustee, establishing the terms and providing for the issuance of the Notes (as supplemented, the 2011 Indenture). The discussion of the Notes in this report is qualified by and subject to the actual terms of the 2011 Indenture .

On and after May 15, 2016, we may redeem all or, from time to time, a part of the Notes at certain redemption prices, plus accrued and unpaid interest. Before May 15, 2014, we may on any one or more occasions redeem up to 35% of the original principal amount of the Notes with the net cash proceeds of one or more equity offerings at a redemption price of 106.625% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, provided that at least 65% of the original principal amount of the Notes remains outstanding after each redemption. In addition, at any time before May 15, 2016, we may redeem the Notes, in whole or in part, at a redemption price equal to 100% of the principal amount plus a “make whole” premium, plus accrued and unpaid interest, if any, to the redemption date. If a “change of control” occurs, subject to certain conditions, we must offer to repurchase from each holder all or any part of that holder’s Notes at a purchase price in cash equal to 101% of the principal amount of the Notes plus accrued and unpaid interest, if any, to the date of purchase. The Indenture contains customary events of default. The Indenture contains covenants that, among other things, limit our ability and the ability of certain of our subsidiaries to incur or guarantee additional indebtedness; pay dividends on our capital stock or redeem capital stock or subordinated indebtedness; transfer or sell assets; make investments; incur liens; enter into transactions with our affiliates; and merge or consolidate with other companies. We were in compliance with all covenants of the Notes as of December 31, 2012.

Other Long-Term Liabilities

Other long-term liabilities consisted of the following as of December 31:

	2012	2011
	(In thousands)	
ARO liability	$146,159	$96,446
Workers’ compensation	18,517	17,026
Separation benefit plans	7,972	6,845
Gas balancing liability	3,838	3,263
Deferred compensation plan	2,779	2,463
	179,265	126,043
Less current portion	12,282	12,213
Total other long-term liabilities	$166,983	$113,830

Estimated annual principal payments under the terms of debt and other long-term liabilities from 2013 through 2017 are $12.3 million, $4.4 million, $44.4 million, $74.9 million, and $4.2 million, respectively.

NOTE 7 – ASSET RETIREMENT OBLIGATIONS

We are required to record the estimated fair value of the liabilities relating to the future retirement of our long-lived assets (AROs). Our oil and natural gas wells are plugged and abandoned when the oil and natural gas reserves in those wells are depleted or the wells are no longer able to produce. The plugging and abandonment liability for a well is recorded in the period in which the obligation is incurred (at the time the well is drilled or acquired). None of our assets are restricted for purposes of settling these AROs. All of our AROs relate to plugging costs associated with our oil and gas wells.

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The following table shows certain information about our AROs for the periods indicated:

	2012	2011
	(In thousands)	
ARO liability, January 1:	$96,446	$69,265
Accretion of discount	4,615	3,838
Liability incurred	56,650 (1)	15,068
Liability settled	(2,788)	(1,009)
Liability Sold	(1,258)	—
Revision of estimates	(7,506) (2)	9,284
ARO liability, December 31:	146,159	96,446
Less current portion	2,953	3,040
Total long-term ARO liability	$143,206	$93,406

(1) The liability incurred increased $46.7 million related to the Noble properties acquired in September 2012.
(2) Plugging liability estimates were revised in March 2012 for updates in the cost of services used to plug wells over the preceding year. Although cost per well increased, a slight decrease in the inflation factor resulted in a decrease in estimated cost. Costs were reviewed each quarter resulting in no change to the March 2012 estimates.

NOTE 8 – INCOME TAXES

A reconciliation of income tax expense, computed by applying the federal statutory rate to pre-tax income to our effective income tax expense is as follows:

	2012	2011	2010
	(In thousands)		
Income tax expense computed by applying the statutory rate	$13,791	$111,651	$83,027
State income tax, net of federal benefit	1,084	8,941	6,030
Statutory depletion and other	1,351	2,543	1,680
Income tax expense	$16,226	$123,135	$90,737

For the periods indicated, the total provision for income taxes consisted of the following:

	2012	2011	2010
	(In thousands)		
Current taxes:			
Federal	$2,084	$(3,159)	$(6,856)
State	(1,388)	743	(3,079)
	696	(2,416)	(9,935)
Deferred taxes:			
Federal	13,768	109,363	88,021
State	1,762	16,188	12,651
	15,530	125,551	100,672
Total provision	$16,226	$123,135	$90,737

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Deferred tax assets and liabilities are comprised of the following at December 31:

	2012	2011
	(In thousands)	
Deferred tax assets:		
Allowance for losses and nondeductible accruals	$74,890	$53,376
Net operating loss carryforward	56,020	47,683
Alternative minimum tax credit carryforward	1,972	—
	132,882	101,059
Deferred tax liability:		
Depreciation, depletion, amortization and impairment	(819,893)	(773,246)
Net deferred tax liability	(687,011)	(672,187)
Current deferred tax asset	8,765	10,936
Non-current—deferred tax liability	$(695,776)	$(683,123)

Realization of the deferred tax assets are dependent on generating sufficient future taxable income. Although realization is not assured, management believes it is more likely than not that the deferred tax asset will be realized. The amount of the deferred tax asset considered realizable, however, could be reduced in the near-term if estimates of future taxable income are reduced. At December 31, 2012, we have federal net operating loss carryforwards of approximately $138.6 million which expire from 2015 to 2032.

NOTE 9 – EMPLOYEE BENEFIT PLANS

Under our 401(k) Employee Thrift Plan, employees who meet specified service requirements may contribute a percentage of their total compensation, up to a specified maximum, to the plan. We may match each employee’s contribution, up to a specified maximum, in full or on a partial basis. We made discretionary contributions under the plan of 95,598, 71,742, and 74,205 shares of common stock and recognized expense of $5.5 million, $4.3 million, and $3.6 million in 2012, 2011, and 2010, respectively.

We provide a salary deferral plan (Deferral Plan) which allows participants to defer the recognition of salary for income tax purposes until actual distribution of benefits which occurs at either termination of employment, death or certain defined unforeseeable emergency hardships. The liability recorded under the Deferral Plan at December 31, 2012 and 2011 was $2.8 million and $2.5 million, respectively. We recognized payroll expense and recorded a liability at the time of deferral.

Effective January 1, 1997, we adopted a separation benefit plan (Separation Plan). The Separation Plan allows eligible employees whose employment is involuntarily terminated or, in the case of an employee who has completed 20 years of service, voluntarily or involuntarily terminated, to receive benefits equivalent to four weeks salary for every whole year of service completed up to a maximum of 104 weeks. To receive payments, the recipient must waive any claims against us in exchange for receiving the separation benefits. On October 28, 1997, we adopted a Separation Benefit Plan for Senior Management (Senior Plan). The Senior Plan provides certain officers and key executives of Unit with benefits generally equivalent to the Separation Plan. The Compensation Committee of the Board of Directors has absolute discretion in the selection of the individuals covered in this plan. On May 5, 2004 we also adopted the Special Separation Benefit Plan (Special Plan). This plan is identical to the Separation Benefit Plan with the exception that the benefits under the plan vest on the earliest of a participant’s reaching the age of 65 or serving 20 years with the company.

On December 31, 2008, we amended all three Plans to be in compliance with Section 409A of the Internal Revenue Code of 1986, as amended. The key amendments to the Plans address, among other things, when distributions may be made, the timing of payments, and the circumstances under which employees become eligible to receive benefits. None of the amendments materially increase the benefits, grants or awards issuable under the Plans. We recognized expense of $2.2 million, $1.9 million, and $1.6 million in 2012, 2011, and 2010, respectively, for benefits associated with anticipated payments from these separation plans.

We have entered into key employee change of control contracts with three of our current executive officers. These severance contracts have an initial three-year term that is automatically extended for one year on each anniversary, unless a notice not to extend is given by us. If a change of control of the company, as defined in the contracts, occurs during the term of the severance contract, then the contract becomes operative for a fixed three-year period. The severance contracts generally provide that the executive's terms and conditions for employment (including position, work location, compensation, and benefits) will not be adversely changed during the three-year period after a change of control. If the executive's employment is terminated (other than for cause, death, or disability), the executive terminates for good reason during such three-year period, or the executive terminates employment for any reason during the 30-day period following the first anniversary of the change of control, and on certain terminations prior to a change of control or in connection with or in anticipation of a change of control, the executive is generally entitled to receive, in addition to certain other benefits, any earned but unpaid compensation; up to 2.9 times the executive's base salary plus annual bonus (based on historic annual bonus); and the company matching contributions that would have been made had the executive continued to participate in the company's 401(k) plan for up to an additional three years.

The severance contract provides that the executive is entitled to receive a payment in an amount sufficient to make the executive whole for any excise tax on excess parachute payments imposed under Section 4999 of the Code. As a condition to receipt of these severance benefits, the executive must remain in the employ of the company prior to change of control and render services commensurate with his position.

NOTE 10 – TRANSACTIONS WITH RELATED PARTIES

Unit Petroleum Company serves as the general partner of 16 oil and gas limited partnerships. Three were formed for investment by third parties and 13 (the employee partnerships) were formed to allow certain of our qualified employees and our directors to participate in Unit Petroleum's oil and gas exploration and production operations. The partnerships for the third party investments were formed in 1984 and 1986. Employee partnerships have been formed for each year beginning with 1984 and ending with 2011. Interests in the employee partnerships were offered to the employees of Unit and its subsidiaries whose annual base compensation was at least a specified amount ($36,000 for 2011 and 2010) and to the directors of Unit.

The employee partnerships formed in 1984 through 1990 were consolidated into a single consolidating partnership in 1993 and the employee partnerships formed in 1991 through 1999 were also consolidated into the consolidating partnership in 2002. The consolidation of the 1991 through the 1999 employee partnerships was done by the general partners under the authority contained in the respective partnership agreements and did not involve any vote, consent or approval by the limited partners. The employee partnerships have each had a set percentage (ranging from 1% to 15%) of our interest in most of the oil and natural gas wells we drill or acquire for our own account during the particular year for which the partnership was formed. The total interest the employees have in our oil and natural gas wells by participating in these partnerships does not exceed one percent.

Amounts received in the years ended December 31, from both public and private Partnerships for which Unit is a general partner are as follows:

	2012	2011	2010
	(In thousands)		
Contract drilling	$246	$352	$529
Well supervision and other fees	$434	$396	$386
General and administrative expense reimbursement	$39	$610	$536

Related party transactions for contract drilling and well supervision fees are the related party's share of such costs. These costs are billed to related parties on the same basis as billings to unrelated parties for such services. General and administrative reimbursements are both direct general and administrative expense incurred on the related party's behalf and indirect expenses allocated to the related parties. Such allocations are based on the related party's level of activity and are considered by management to be reasonable.

On November 21, 2011, Superior Pipeline Company, L.L.C. (Superior), a wholly-owned subsidiary of ours, entered a Gas Purchase Agreement with Sullivan and Company, L.L.C. (Sullivan), an Oklahoma limited liability company for which Robert Sullivan, Jr., one the Company's directors, is a principal. Under the terms of the agreement, Sullivan is selling natural gas from 23 wells in northern Oklahoma to Superior, which will gather, process and sell purchased volumes. The term of the agreement is for a five-year period, after which it will be on a year-to-year basis until terminated by either party on sixty days written notice. Volumes sold are not dedicated under the agreement, and volumes are purchased at Superior's discretion. Proceeds from sales of volumes gathered and processed under the agreement are to be paid 90% to Sullivan and 10% to Superior. The agreement is the result of an arm's length transaction reflecting market rate terms and conditions comparable to other gas purchase agreements negotiated by Superior with similarly situated sellers of natural gas in the same market during the same general time frame.

One of our directors, G. Bailey Peyton IV, also serves as the President and a significant investor in Upland Resources, L.L.C., a small independent oil and natural gas exploration company, and as Manager of Peyton Royalties, LP, a family-controlled limited partnership that owns royalty rights in wells in the Texas and Oklahoma Panhandles. In the ordinary course of business during 2012 the Company drilled three wells, under its usual standard dayrate contracts, in which Upland Resources, L.L.C. was a participant, for which the Company received payments of approximately $1.6 million from Upland Resources, L.L.C. The Company also paid royalties during 2012, primarily due to its status as successor in interest to prior transactions and as operator of the wells involved and, in some cases, as lessee, with respect to certain wells in which Mr. Peyton, members of Mr. Peyton's family, and Peyton Royalties, LP have an interest. Such payments totaled approximately $1.2 million during 2012. Our Audit Committee and the board, in accordance with the Policy, have determined that these arrangements are in the best interest of the Company.

NOTE 11 – SHAREHOLDER RIGHTS PLAN

We maintain a Shareholder Rights Plan (the Plan) designed to deter coercive or unfair takeover tactics, to prevent a person or group from gaining control of us without offering fair value to all our shareholders and to deter other abusive takeover tactics, which are not in the best interest of shareholders.

Under the terms of the Plan, each share of common stock is accompanied by one right, which given certain acquisition and business combination criteria, entitles the shareholder to purchase from us one one-hundredth of a newly issued share of Series A Participating Cumulative Preferred Stock at a price subject to adjustment by us or to purchase from an acquiring company certain shares of its common stock or the surviving company's common stock at 50% of its value.

The rights become exercisable 10 days after we learn that an acquiring person (as defined in the Plan) has acquired 15% or more of the outstanding common stock of Unit or 10 business days after the commencement of a tender offer, which would result in a person owning 15% or more of our shares. We can redeem the rights for $0.01 per right at any date before the earlier of (i) the close of business on the 10th day following the time we learn that a person has become an acquiring person or (ii) May 19, 2015 (the "Expiration Date"). The rights will expire on the Expiration Date, unless redeemed earlier by Unit.

NOTE 12 – STOCK-BASED COMPENSATION

For restricted stock awards, stock options, and stock appreciation rights (SARs), we had:

	2012	2011	2010
	(In millions)		
Recognized stock compensation expense	$11.4	$10.0	$10.8
	2.7	2.5	2.7

Capitalized stock compensation cost for our oil and natural gas properties			
Tax benefit on stock based compensation	4.5	3.9	4.1

The remaining unrecognized compensation cost related to unvested awards at December 31, 2012 is approximately \$11.3 million with \$2.1 million of this amount anticipated to be capitalized. The weighted average period of time over which this cost will be recognized is 0.8 years.

At our annual meeting of stockholders held on May 2, 2012, our stockholders approved the Unit Corporation Stock and Incentive Compensation Plan Amended and Restated May 2, 2012 (the amended plan). The amended plan allows us to grant stock-based and cash-based compensation to our employees (including employees of subsidiaries) as well as non-employee

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directors. The amended plan succeeds the Non-employee Directors' 2000 Stock Option Plan (the option plan), and no new awards will be issued under the option plan.

The amended plan allows for the issuance of 3.3 million shares of common stock with 2.0 million shares being the maximum number of shares that can be issued as "incentive stock options." Awards under this plan may be granted in any one or a combination of the following:

- incentive stock options under Section 422 of the Internal Revenue Code;
- non-qualified stock options;
- performance shares;
- performance units;
- restricted stock;
- restricted stock units;
- stock appreciation rights;
- cash based awards; and
- other stock-based awards.

This plan also contains various limits as to the amount of awards that can be given to an employee in any fiscal year. All awards are generally subject to the minimum vesting periods, as determined by our Compensation Committee and included in the award agreement.

The table below shows the estimates of the fair value of stock options granted to our non-employee directors under the option plan in 2011 and 2010 using the Black-Scholes model and applying the estimated values also presented in the table:

	2011	2010
Options granted	31,500	52,504 (1)
Stock appreciation rights	—	—
Estimated fair value (in millions)	$0.7	$0.8
Estimate of stock volatility	0.48	0.45
Estimated dividend yield	— %	— %
Risk free interest rate	2 %	2 %
Expected life range based on prior experience (in years)	5	5
Forfeiture rate	— %	— %

(1) On May 29, 2009, eight of our directors were each issued 3,063 options contingent on shareholder approval, which was received at the May 5, 2010 annual shareholders' meeting. These 24,504 options granted and vested simultaneously with that approval.

Expected volatilities are based on the historical volatility of our stock. We use historical data to estimate option exercise and termination rates within the model and aggregate groups that have similar historical exercise behavior for valuation purposes. To date, we have not paid dividends on our stock. The risk free interest rate is computed from the United States Treasury Strips rate using the term over which it is anticipated the grant will be exercised.

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SARs

Activity pertaining to SARs granted under the Unit Corporation Stock and Incentive Compensation Plan is as follows:

	Number of Shares	Weighted Average Grant Date Price
Outstanding at January 1, 2010	145,901	$46.59
Granted	—	—
Exercised	—	—
Forfeited	—	—
Outstanding at December 31, 2010	145,901	46.59
Granted	—	—
Exercised	—	—
Forfeited	—	—
Outstanding at December 31, 2011	145,901	46.59
Granted	—	—
Exercised	—	—
Forfeited	—	—
Outstanding at December 31, 2012	145,901	$46.59

There were no SARs granted in 2012, 2011, or 2010. The SARs expire after 10 years from the date of the grant. In 2012, no shares vested. In 2011 and 2010, 33,745, and 48,632 shares vested, respectively. The aggregate intrinsic value of the 145,901 shares outstanding at December 31, 2012 was $0.1 million with a weighted average remaining contractual term of 4.6 years.

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Restricted Stock

Activity pertaining to restricted stock awards granted under the amended plan is as follows:

Employees	Number of Shares	Weighted Average Grant Date Price
Nonvested at January 1, 2010	507,071	$47.46
Granted	450,355	41.09
Vested	(496,497)	47.09
Forfeited	(14,804)	44.25
Nonvested at December 31, 2010	446,125	47.39
Granted	211,050	55.91
Vested	(190,262)	43.32
Forfeited	(18,952)	44.55
Nonvested at December 31, 2011	447,961	47.44
Granted	376,445	47.37
Vested	(220,788)	45.66
Forfeited	(14,091)	45.37
Nonvested at December 31, 2012	589,527	$48.11

Non-Employee Directors	Number of Shares	Weighted Average Grant Date Price
Nonvested at December 31, 2011	—	$—
Granted	24,606	40.23
Vested	—	—
Forfeited	—	—
Nonvested at December 31, 2012	24,606	$40.23

The restricted stock awards vest in periods ranging from 2 to 3 years, except for a portion of those granted to certain executive officers. As to those executive officers, 30% of the shares granted, or 46,441 shares in 2012 and 20,062 shares in 2011 (the performance shares), will cliff vest in the first half of 2015 and 2014, respectively. The actual number of performance shares that vest in 2014 and 2015 will be based on the company’s achievement of certain performance criteria over a three-year period, and will range from 50% to 150% of the restricted shares granted as performance shares. Based on the first two years' results, the participants would receive more than 100% of the performance based shares.

The fair value of the restricted stock granted in 2012, 2011, and 2010 at the grant date was $16.9 million, $10.8 million, and $16.9 million, respectively. The aggregate intrinsic value of the 220,788 shares of restricted stock on their 2012 vesting date was $10.0 million. The aggregate intrinsic value of the 614,133 shares outstanding subject to vesting at December 31, 2012 was $27.7 million with a weighted average remaining life of 1.1 years.

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Employee Stock Option Plan

The Stock Option Plan, provided the granting of options for up to 2,700,000 shares of common stock to officers and employees. The option plan permitted the issuance of qualified or nonqualified stock options. Options granted typically became exercisable at the rate of 20% per year one year after being granted and expire after 10 years from the original grant date. The exercise price for options granted under this plan was the fair market value of the common stock on the date of the grant. In 2006, as a result of the approval of the adoption of the Unit Corporation Stock and Incentive Compensation Plan, no further awards were made under this plan.

Activity pertaining to the Stock Option Plan is as follows:

	Number of Shares	Weighted Average Exercise Price
Outstanding at January 1, 2010	219,625	$29.61
Granted	—	—
Exercised	(32,360)	20.35
Forfeited	(2,500)	37.83
Outstanding at December 31, 2010	184,765	31.11
Granted	—	—
Exercised	(42,285)	28.29
Forfeited	(3,500)	53.90
Outstanding at December 31, 2011	138,980	31.39
Granted	—	—
Exercised	(18,850)	20.38
Forfeited	(2,100)	37.83
Outstanding at December 31, 2012	118,030	$33.03

There were no shares that vested in 2012 or 2011. The total grant date fair value of the 6,200 shares vesting in 2010 was $0.2 million. The intrinsic value of options exercised in 2012 was $0.4 million. Total cash received from the options exercised in 2012 was $0.1 million.

	Outstanding and Exercisable Options at December 31, 2012		
Exercise Prices	Number of Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price
$21.50 - $22.95	37,410	0.9 years	$22.76
$37.69 - $37.83	80,620	2.0 years	$37.80

Options for 118,030, 138,980, and 184,765 shares were exercisable with weighted average exercise prices of $33.03, $31.39, and $31.11 at December 31, 2012, 2011, and 2010, respectively. The aggregate intrinsic value of the 118,030 shares outstanding subject to options at December 31, 2012 was $1.4 million with a weighted average remaining contractual term of 1.7 years.

Non-Employee Directors' Stock Option Plan

Under the Unit Corporation 2000 Non-Employee Directors’ Stock Option Plan, on the first business day following each annual meeting of shareholders, each person who was then a member of our Board of Directors and who was not then an employee of the company or any of its subsidiaries was granted an option to purchase 3,500 shares of common stock. The option price for each stock option was the fair market value of the common stock on the date the stock options were granted. The term of each option is 10 years and cannot be increased and no stock options were to be exercised during the first six months of its term except in case of death. As mentioned above, on May 2, 2012, our stockholders approved the amended plan which succeeds this plan, and no new awards will be issued under the non-employee director option plan.

On the first day following the 2009 annual meeting, each non-employee director was granted 437 shares of common stock. Effective with the adoption of the amendments mentioned above, a contingent one-time grant of 3,063 shares to each non-employee director was made on May 29, 2009. These contingent option awards vested when the stockholders approved the amended plan at the May 5, 2010 annual meeting.

Activity pertaining to the Directors' Plan is as follows:

	Number of Shares	Weighted Average Exercise Price
Outstanding at January 1, 2010	143,496	$49.38
Granted	52,504	37.62
Exercised	(3,500)	17.54
Forfeited	(14,000)	58.20
Outstanding at December 31, 2010	178,500	48.77
Granted	31,500	53.81
Exercised	(10,500)	21.96
Forfeited	—	—
Outstanding at December 31, 2011	199,500	48.37
Granted	—	—
Exercised	(7,000)	20.28
Forfeited	—	—
Outstanding at December 31, 2012	192,500	$49.39

The total grant date fair value of the 31,500 and 52,504 shares vesting in 2011 and 2010, respectively, was $0.7 million and $0.8 million, respectively. The intrinsic value of the 7,000 options exercised in 2012 was $0.2 million. Total cash received from options exercised in 2012 was $0.1 million.

	Outstanding and Exercisable Options at December 31, 2012		
Exercise Prices	Number of Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price
$20.46	7,000	0.3 years	$20.46
$28.23 - $41.21	80,500	5.4 years	$36.45
$53.81 - $73.26	105,000	5.5 years	$61.24

Options for 192,500, 199,500, and 178,500 shares were exercisable with weighted average exercise prices of $49.39, $48.37, and $48.77 at December 31, 2012, 2011, and 2010, respectively. The aggregate intrinsic value of the shares outstanding subject to options at December 31, 2012 was $0.9 million with a weighted average remaining contractual term of 5.3 years.

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NOTE 13 – DERIVATIVES

Commodity Derivatives

We have entered into various types of derivative transactions covering some of our projected natural gas, NGLs, and oil production. These transactions are intended to reduce our exposure to market price volatility by setting the price(s) we will receive for that production. Our decisions on the price(s), type, and quantity of our production hedged is based, in part, on our view of current and future market conditions. As of December 31, 2012, our derivative transactions consisted of the following types of hedges:

- Swaps. We receive or pay a fixed price for the hedged commodity and pay or receive a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

- Collars. A collar contains a fixed floor price (put) and a ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, we receive the fixed price and pay the market price. If the market price is between the call and the put strike price, no payments are due from either party.

We have documented policies and procedures to monitor and control the use of derivative instruments. We do not engage in derivative transactions for speculative purposes. In August 2012, we determined on a prospective basis, to enter into economic hedges without electing cash flow hedge accounting. Therefore, the change in fair value, on all commodity derivatives entered into after that determination, will be reflected in the income statement and not in accumulated other comprehensive income (OCI).

At December 31, 2012, the following designated cash flow hedges were outstanding:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Jan'13 – Dec'13	Natural gas – swap	60,000 MMBtu/day	$3.56	IF – NYMEX (HH)
Jan'13 – Dec'13	Crude oil – swap	5,500 Bbl/day	$99.71	WTI – NYMEX
Jan'13 – Dec'13	Natural gas – collar	20,000 MMBtu/day	$3.25-3.72	IF – NYMEX (HH)

At December 31, 2012, the following non-designated hedges were outstanding:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Jan'13 – Dec'13	Natural gas – swap	20,000 MMBtu/day	$3.94	IF – NYMEX (HH)
Jan'13 – Dec'13	Crude oil – swap	1,000 Bbl/day	$90.63	WTI – NYMEX
Jan'14 – Dec'14	Crude oil – swap	1,000 Bbl/day	$90.60	WTI – NYMEX

Subsequent to December 31, 2012, the following non-designated hedges were entered into:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Feb'13 – Dec'13	Crude oil – swap	2,000 Bbl/day	$96.58	WTI – NYMEX
Jan'14 – Dec'14	Crude oil – swap	1,000 Bbl/day	$92.20	WTI – NYMEX
Jan'14 – Dec'14	Crude oil – collar	2,000 Bbl/day	$90.00-95.00	WTI – NYMEX

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The following tables present the fair values of our derivative transactions and the location within our balance sheets where those values are recorded:

	Balance Sheet Location	Derivative Assets Fair Value December 31, 2012 (In thousands)	December 31, 2011
Derivatives designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative assets	$13,674	$31,938
Long-term	Non-current derivative assets	—	4,514
Total derivatives designated as hedging instruments		13,674	36,452
Derivatives not designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative assets	2,878	—
Long-term	Non-current derivative assets	—	—
Total derivatives not designated as hedging instruments		2,878	—
Total derivative assets		$16,552	$36,452

	Balance Sheet Location	Derivative Liabilities Fair Value December 31, 2012 (In thousands)	December 31, 2011
Derivatives designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative liabilities	$1,005	$2,657
Long-term	Non-current derivative liabilities	—	—
Total derivatives designated as hedging instruments		1,005	2,657
Derivatives not designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative liabilities	943	—
Long-term	Non-current derivative liabilities	562	—
Total derivatives not designated as hedging instruments		1,505	—
Total derivative liabilities		$2,510	$2,657

If a legal right of set-off exists, we net the value of the derivative transactions we have with the same counterparty in our balance sheets.

We recognize in accumulated other comprehensive income (OCI) the effective portion of any changes in fair value and reclassify the recognized gains (losses) on the sales to oil and natural gas revenue as the underlying transactions are settled. As of December 31, 2012 and 2011, we had a gain of $7.6 million and $19.0 million, net of tax, respectively, in accumulated OCI.

Based on market prices at December 31, 2012, we expect to transfer a gain of approximately $7.6 million, net of tax, included in accumulated OCI during the next 12 months in the related month of settlement. The cash flow derivative instruments existing as of December 31, 2012 are expected to mature by December 31, 2013.

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UNIT CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

For our economic hedges that we elected not to apply cash flow accounting to, any changes in their fair value occurring before their maturity (i.e., temporary fluctuations in value) are reported in gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net in our consolidated statements of income. Changes in the fair value of derivatives designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in OCI until the hedged item is recognized into earnings. When the hedged item is recognized into earnings, it is reported in oil and natural gas revenues. Any change in fair value resulting from ineffectiveness is recognized in gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net. Previously, we reported all realized and unrealized gains (losses) in oil and natural gas revenues and now we reflect gains (losses) on non-designated hedges and ineffectiveness from cash flow hedges along with other revenue items in other income (expense) below income from operations. Prior year amounts have been reclassified to conform to current year presentation.

Effect of Derivative Instruments on the Consolidated Balance Sheets (cash flow hedges) for the year ended December 31:

Derivatives in Cash Flow Hedging Relationships	Amount of Gain or (Loss) Recognized in Accumulated OCI on Derivative (Effective Portion) (1)	
	2012	2011
	(In thousands)	
Commodity derivatives	$7,587	$19,026

(1) Net of taxes.

Effect of derivative instruments on the Consolidated Statements of Income (cash flow hedges) for the year ended December 31:

Derivative Instrument	Location of Gain or (Loss) Reclassified from Accumulated OCI into Income & Location of Gain or (Loss) Recognized in Income	Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income (1)		Amount of Gain or (Loss) Recognized in Income (2)	
		2012	2011	2012	2011
		(In thousands)			
Commodity derivatives	Oil and natural gas revenue (1)	51,853	4,699	—	—
Commodity derivatives	Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net (2)	—	—	(2,616)	2,749
Interest rate swaps	Interest, net	—	(1,734)	—	—
	Total	$51,853	$2,965	$(2,616)	$2,749

(1) Effective portion of gain (loss).
(2) Ineffective portion of gain (loss).

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UNIT CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Effect of Derivative Instruments on the Consolidated Statements of Income (derivatives not designated as hedging instruments) for the year ended December 31:

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Income on Derivative	Amount of Gain or (Loss) Recognized in Income on Derivative	
		2012	2011
		(In thousands)	
Commodity derivatives	Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net	$1,373	$(1,047)
Total		$1,373	$(1,047)

NOTE 14 – FAIR VALUE MEASUREMENTS

Fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants (in either case, an exit price). To estimate an exit price, a three-level hierarchy is used prioritizing the valuation techniques used to measure fair value into three levels with the highest priority given to Level 1 and the lowest priority given to Level 3. The levels are summarized as follows:

- Level 1—unadjusted quoted prices in active markets for identical assets and liabilities.
- Level 2—significant observable pricing inputs other than quoted prices included within level 1 that are either directly or indirectly observable as of the reporting date. Essentially, inputs (variables used in the pricing models) that are derived principally from or corroborated by observable market data.
- Level 3—generally unobservable inputs which are developed based on the best information available and may include our own internal data.

The inputs available to us determine the valuation technique we use to measure the fair values of our financial instruments.

The following tables set forth our recurring fair value measurements:

	December 31, 2012			
	Level 2	Level 3	Effect of Netting	Total
	(In thousands)			
Financial assets (liabilities):				
Commodity derivatives:				
Assets	$18,555	$—	$(2,003)	$16,552
Liabilities	(3,918)	(595)	2,003	(2,510)
	$14,637	$(595)	$—	$14,042

	December 31, 2011			
	Level 2	Level 3	Effect of Netting	Total
	(In thousands)			
Financial assets (liabilities):				
Commodity derivatives:				
Assets	$9,698	$34,321	$(7,567)	$36,452
Liabilities	(9,518)	(706)	7,567	(2,657)
	$180	$33,615	$—	$33,795

Certain natural gas fixed price swaps were transferred from Level 3 to Level 2 as of March 31, 2012 because of improvements in our ability to obtain and corroborate observable significant inputs to assess the fair value. Our policy is to recognize transfers either in or out of fair value hierarchy levels as of the end of the quarterly reporting period in which the event or change in circumstances causing the transfer occurred.

The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the table above.

Level 2 Fair Value Measurements

Commodity Derivatives. We measure the fair values of our crude oil swaps using estimated internal discounted cash flow calculations based on the NYMEX futures index.

Level 3 Fair Value Measurements

Interest Rate Swaps. The fair values of our interest rate swaps are based on estimates provided by our respective counterparties and reviewed internally against established index prices and other sources.

Commodity Derivatives. The fair values of our natural gas, NGLs and basis swaps are estimated using internal discounted cash flow calculations based on forward price curves, quotes obtained from brokers for contracts with similar terms, or quotes obtained from counterparties to the agreements.

The following tables are reconciliations of our level 3 fair value measurements:

	Net Derivatives			
	For the Year Ended, December 31, 2012		For the Year Ended, December 31, 2011	
	Interest Rate Swaps	Commodity Swaps	Interest Rate Swaps	Commodity Swaps
	(In thousands)			
Beginning of period	$—	$33,615	$(1,614)	$10,868
Total gains or losses (realized and unrealized):				
Included in earnings [1]	—	24,484	(1,734)	20,086
Included in other comprehensive income (loss)	—	(11,641)	1,614	22,503
Settlements	—	(25,129)	1,734	(19,842)
Transfers out of Level 3 into Level 2	—	(21,924)	—	—
End of period	$—	$(595)	$—	$33,615
Total gains (losses) for the period included in earnings attributable to the change in unrealized	$—	$(645)	$—	$244

gain relating to assets still held at end of period

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(1) Interest rate swaps and commodity sales swaps and collars are reported in the consolidated statements of operations in interest expense, oil and gas revenues (for cash flow hedges), and gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net, respectively.

The following table provides quantitative information about our Level 3 unobservable inputs at December 31, 2012:

	Fair Value (In thousands)	Valuation Technique	Unobservable Input	Range
Commodity collars [1]	$ (595)	Discounted cash flow	Forward commodity price curve	$0.09-$0.56

(1) The commodity contracts detailed in this category include non-exchange-traded natural gas collars that are valued based on NYMEX. The forward pricing range represents the low and high price expected to be received within the settlement period.

Based on our valuation at December 31, 2012, we determined that the non-performance risk with regard to our counterparties was immaterial.

Fair Value of Other Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with accounting guidance for financial instruments. We have determined the estimated fair values by using available market information and valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

At December 31, 2012, the carrying values on the consolidated balance sheets for cash and cash equivalents (classified as Level 1), accounts receivable, accounts payable, other current assets, and current liabilities approximate their fair value because of their short term nature.

Based on the borrowing rates currently available to us for credit agreement debt with similar terms and maturities and also considering the risk of our non-performance, long-term debt under our credit agreement at December 31, 2012 approximates its fair value. This debt would be classified as Level 2.

The carrying amounts of long-term debt, net of unamortized discount, associated with the Notes reported in the consolidated balance sheets at December 31, 2012 and December 31, 2011 were $645.3 million and $250.0 million, respectively. We estimate the fair value of these Notes using quoted marked prices at December 31, 2012 and December 31, 2011 were $687.7 million and $250.6 million, respectively. These Notes would be classified as Level 2.

NOTE 15 – COMMITMENTS AND CONTINGENCIES

We lease office space or yards in Edmond, Oklahoma City, and Tulsa, Oklahoma; Houston, Texas; Englewood, Colorado; Pinedale, Wyoming; and Pittsburgh, Pennsylvania under the terms of operating leases expiring through September, 2017. Additionally, we have several compressor rentals, equipment leases, and lease space on short-term commitments to stack excess drilling rig equipment and production inventory. Future minimum rental payments under the terms of the leases are approximately $8.4 million, $3.3 million, $0.6 million, $0.3 million, and $0.1 million in 2013-2017, respectively. Total rent expense incurred was $14.0 million, $8.5 million, and $7.1 million in 2012, 2011, and 2010, respectively.

The Unit 1984 Oil and Gas Limited Partnership and the 1986 Energy Income Limited Partnership agreements along with the employee oil and gas limited partnerships require, on the election of a limited partner, that we repurchase the limited partner's interest at amounts to be determined by appraisal in the future. These repurchases in any one year are limited to 20% of the units outstanding. We made repurchases of $56,000 in 2012, $22,000 in 2011, and $22,000 in 2010.

We manage our exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. We also conduct periodic reviews, on a company-wide basis, to identify changes in our environmental risk profile. These reviews evaluate whether there is a probable liability, its amount, and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of time directly to any possible remediation effort. As it relates to evaluations of purchased properties, depending on the extent of an identified environmental problem, we may exclude a property from the acquisition, require the seller to remediate the property to our satisfaction, or agree to assume liability for the remediation of the property.

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We have not historically experienced any environmental liability while being a contract driller since the greatest portion of risk is borne by the operator. Any liabilities we have incurred have been small and have been resolved while the drilling rig is on the location and the cost has been included in the direct cost of drilling the well.

At December 31, 2012, we had commitments to purchase $1.8 million for a processing plant within the next twelve months.

We are subject to various legal proceedings arising in the ordinary course of our various businesses none of which, in our opinion, will result in judgments which would have a material adverse effect on our financial position, operating results or cash flows.

NOTE 16 – INDUSTRY SEGMENT INFORMATION

We have three main business segments offering different products and services:

- Contract drilling,
- Oil and natural gas, and
- Mid-stream

The contract drilling segment is engaged in the land contract drilling of oil and natural gas wells. The oil and natural gas segment is engaged in the development, acquisition, and production of oil and natural gas properties and the mid-stream segment is engaged in the buying, selling, gathering, processing, and treating of natural gas.

We evaluate each segment’s performance based on its operating income, which is defined as operating revenues less operating expenses and depreciation, depletion, amortization, and impairment. Our oil and natural gas production outside the United States is not significant.

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The following table provides certain information about the operations of each of our segments:

	2012	2011	2010
	(In thousands)		
Revenues:			
Contract drilling	$579,368	$536,872	$356,527
Elimination of inter-segment revenue	(49,649)	(52,221)	(40,143)
Contract drilling net of inter-segment revenue	529,719	484,651	316,384
Oil and natural gas	567,944	514,614	399,771
Gas gathering and processing	290,773	284,248	201,320
Elimination of inter-segment revenue	(73,313)	(76,010)	(46,804)
Gas gathering and processing net of inter-segment revenue	217,460	208,238	154,516
Total revenues	$1,315,123	$1,207,503	$870,671
Operating income:			
Contract drilling	$159,188	$135,085	$59,601
Oil and natural gas	(77,221) (3)	199,993	175,613
Gas gathering and processing	5,780	17,278	16,985
Total operating income (1)	87,747	352,356	252,199
General and administrative expense	(33,086)	(30,055)	(26,152)
Interest expense, net	(14,137)	(4,167)	—
Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net	(1,243)	1,702	1,036
Other income (loss), net	121	(834)	10,138
Income before income taxes	$39,402	$319,002	$237,221
Identifiable assets:			
Contract drilling	$1,079,736	$1,118,666	$998,658
Oil and natural gas	2,214,029	1,820,492	1,441,797
Gas gathering and processing	413,708	247,763	176,596
Total identifiable assets (2)	3,707,473	3,186,921	2,617,051
Corporate assets	53,647	69,799	52,189
Total assets	$3,761,120	$3,256,720	$2,669,240
Capital expenditures:			
Contract drilling	$77,520	$162,208	$118,806
Oil and natural gas	1,128,349	580,055	463,870
Gas gathering and processing	183,162	79,355	29,815
Other	28,071	10,791	6,417
Total capital expenditures	$1,417,102	$832,409	$618,908
Depreciation, depletion, amortization, and impairment:			
Contract drilling	$81,007	$79,667	$69,970
Oil and natural gas:			
Depreciation, depletion, and amortization	211,347	183,350	118,793
Impairment of oil and natural gas properties	283,606 (3)	—	—
Gas gathering and processing	24,388 (4)	16,101	15,385
Other	2,279	1,333	976
Total depreciation, depletion, amortization, and impairment	$602,627	$280,451	$205,124

(1) Operating income is total operating revenues less operating expenses, depreciation, depletion, amortization, and impairment and does not include general corporate expenses, gain (loss) on non-designated hedges and hedge

ineffectiveness, interest expense, other income (loss), or income taxes.

(2) Identifiable assets are those used in Unit's operations in each industry segment. Corporate assets are principally cash and cash equivalents, short-term investments, corporate leasehold improvements, furniture and equipment.

(3) In June 2012 and December 2012, due to low 12-month average commodity prices, we incurred non-cash ceiling test write downs of our oil and natural gas properties of $115.9 million pre-tax ($72.1 million net of tax) and $167.7 million pre-tax ($104.4 million net of tax), respectively.

(4) Depreciation, depletion, amortization, and impairment for gas gathering and processing includes a $1.2 million write down of our Erick system.

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UNIT CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

NOTE 17 – SELECTED QUARTERLY FINANCIAL INFORMATION

Summarized unaudited quarterly financial information is as follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
	(In thousands except per share amounts)			
2012:				
Revenues	$333,966	$327,785	$321,790	$331,582
Gross profit (loss)	$95,912	$(22,253)	$95,921	$(81,833) (1)
Net income (loss)	$52,439	$(19,302)	$46,586	$(56,547)
Net income (loss) per common share:				
Basic	$1.10	$(0.40)	$0.97	$(1.18) (2)
Diluted	$1.09	$(0.40)	$0.97	$(1.18)
2011:				
Revenues	$250,096	$287,829	$322,237	$347,341
Gross profit	$76,078	$85,780	$94,306	$96,192 (1)
Net income	$41,027	$49,819	$53,360	$51,661
Net income per common share:				
Basic	$0.86	$1.05	$1.12	$1.08
Diluted	$0.86	$1.04	$1.11	$1.08

(1) Gross profit excludes general and administrative expense, interest expense, gain (loss) on non-designated hedges and hedge ineffectiveness, and other income (loss).

(2) Due to the effect of rounding the basic earnings or diluted per share for the year's four quarters does not equal annual earnings per share.

SUPPLEMENTAL OIL AND GAS DISCLOSURES
(UNAUDITED)

Our oil and gas operations are substantially located in the United States. We do have operations in Canada that are insignificant. The capitalized costs at year-end and costs incurred during the year were as follows:

	2012	2011	2010
	(In thousands)		
Capitalized costs:			
Proved properties	$3,822,381	$3,302,032	$2,738,093
Unproved properties	521,659	185,632	175,065
	4,344,040	3,487,664	2,913,158
Accumulated depreciation, depletion, amortization, and impairment	(2,216,787)	(1,724,312)	(1,542,352)
Net capitalized costs	$2,127,253	$1,763,352	$1,370,806
Cost incurred:			
Unproved properties acquired	$420,467	$70,999	$75,739
Proved properties acquired	225,669	50,013	50,000
Exploration	46,467	43,836	48,304
Development	390,649	391,862	279,903
Asset retirement obligation	45,097	23,345	9,924
Total costs incurred	$1,128,349	$580,055	$463,870

The following table shows a summary of the oil and natural gas property costs not being amortized at December 31, 2012, by the year in which such costs were incurred:

	2012	2011	2010	2009 and Prior	Total
	(In thousands)				
Undeveloped leasehold acquired and wells in progress	$428,375	$62,750	$19,975	$10,559	$521,659

Unproved properties not subject to amortization relates to properties which are not individually significant and consist primarily of lease acquisition costs. The evaluation process associated with these properties has not been completed and therefore, the company is unable to estimate when these costs will be included in the amortization calculation.

The results of operations for producing activities are as follows:

	2012	2011	2010
	(In thousands)		
Revenues	$557,003	$505,450	$392,229
Production costs	(131,389)	(115,400)	(91,143)
Depreciation, depletion, amortization, and impairment	(492,475)	(181,960)	(117,793)
	(66,861)	208,090	183,293
Income tax (expense) benefit	27,533	(80,323)	(70,110)
Results of operations for producing activities (excluding corporate overhead and financing costs)	$(39,328)	$127,767	$113,183

Estimated quantities of proved developed oil, NGLs, and natural gas reserves and changes in net quantities of proved developed and undeveloped oil, NGLs, and natural gas reserves were as follows:

	Oil Bbls	Liquids Bbls	Natural Gas Mcf
	(In thousands)		
2012:			
Proved Developed and Undeveloped Reserves:			
Beginning of Year	20,255	22,087	442,135
Revision of Previous Estimates (1)	(1,747)	(2,682)	(55,110)
Extensions and Discoveries	5,014	4,819	54,761
Infill Reserves in Existing Proved Fields	4,196	3,018	25,057
Purchases of Minerals in Place	2,830	11,098	141,494
Production	(3,279)	(2,796)	(48,930)
Sales	(5,271)	(378)	(3,760)
End of Year	21,998	35,166	555,647
Proved Developed Reserves:			
Beginning of Year	15,618	16,649	372,311
End of Year	16,441	25,657	452,844
Proved Undeveloped Reserves:			
Beginning of Year	4,637	5,438	69,824
End of Year	5,557	9,509	102,803
2011:			
Proved Developed and Undeveloped Reserves:			
Beginning of Year	17,494	16,117	420,486
Revision of Previous Estimates (1)	374	2,112	(30,510)
Extensions and Discoveries	3,477	3,924	39,836
Infill Reserves in Existing Proved Fields	1,229	1,780	15,592
Purchases of Minerals in Place	192	393	40,835
Production	(2,511)	(2,239)	(44,104)
Sales	—	—	—
End of Year	20,255	22,087	442,135
Proved Developed Reserves:			
Beginning of Year	12,773	12,088	346,928
End of Year	15,618	16,649	372,311
Proved Undeveloped Reserves:			
Beginning of Year	4,721	4,029	73,558
End of Year	4,637	5,438	69,824
2010:			
Proved Developed and Undeveloped Reserves:			
Beginning of Year	11,669	14,653	419,061
Revision of Previous Estimates (1)	434	(1,559)	(25,007)
Extensions and Discoveries	3,473	878	31,328
Infill Reserves in Existing Proved Fields	2,152	3,482	34,128
Purchases of Minerals in Place	1,293	212	1,732
Production	(1,521)	(1,549)	(40,756)
Sales	(6)	—	—
End of Year	17,494	16,117	420,486
Proved Developed Reserves:			
Beginning of Year	9,183	11,538	338,217
End of Year	12,773	12,088	346,928

Proved Undeveloped Reserves:			
Beginning of Year	2,486	3,115	80,844
End of Year	4,721	4,029	73,558

(1) Natural gas revisions of previous estimates decreased primarily due to a decline in natural gas prices.

Estimates of oil, NGLs, and natural gas reserves require extensive judgments of reservoir engineering data. Assigning monetary values to such estimates does not reduce the subjectivity and changing nature of such reserve estimates. Indeed the uncertainties inherent in the disclosure are compounded by applying additional estimates of the rates and timing of production and the costs that will be incurred in developing and producing the reserves. The information set forth in this report is, therefore, subjective and, since judgments are involved, may not be comparable to estimates submitted by other oil and natural gas producers. In addition, since prices and costs do not remain static, and no price or cost escalations or de-escalations have been considered, the results are not necessarily indicative of the estimated fair market value of estimated proved reserves, nor of estimated future cash flows.

The standardized measure of discounted future net cash flows (SMOG) was calculated using 12-month average prices and year-end costs and statutory tax rates, adjusted for permanent differences that relate to existing proved oil, NGLs, and natural gas reserves. SMOG as of December 31 is as follows:

	2012	2011	2010
	(In thousands)		
Future cash flows	$4,522,351	$4,583,629	$3,745,046
Future production costs	(1,405,773)	(1,277,856)	(1,054,630)
Future development costs	(431,673)	(340,992)	(303,152)
Future income tax expenses	(762,519)	(952,736)	(799,260)
Future net cash flows	1,922,386	2,012,045	1,588,004
10% annual discount for estimated timing of cash flows	(842,430)	(924,136)	(732,918)
Standardized measure of discounted future net cash flows relating to proved oil, NGLs, and natural gas reserves	$1,079,956	$1,087,909	$855,086

The principal sources of changes in the standardized measure of discounted future net cash flows were as follows:

	2012	2011	2010
	(In thousands)		
Sales and transfers of oil and natural gas produced, net of production costs	$(425,626)	$(389,339)	$(301,086)
Net changes in prices and production costs	(321,099)	115,852	379,097
Revisions in quantity estimates and changes in production timing	(148,648)	(38,336)	(67,116)
Extensions, discoveries and improved recovery, less related costs	432,058	401,134	340,771
Changes in estimated future development costs	51,587	37,742	15,974
Previously estimated cost incurred during the period	104,377	45,327	45,327
Purchases of minerals in place	283,774	58,567	42,280
Sales of minerals in place	(112,359)	(29)	(120)
Accretion of discount	157,842	128,492	77,536
Net change in income taxes	94,678	(60,675)	(200,815)
Other—net	(124,537)	(65,912)	(23,097)
Net change	(7,953)	232,823	308,751
Beginning of year	1,087,909	855,086	546,335
End of year	$1,079,956	$1,087,909	$855,086

Certain information concerning the assumptions used in computing SMOG and their inherent limitations are discussed below. We believe this information is essential for a proper understanding and assessment of the data presented.

The assumptions used to compute SMOG do not necessarily reflect our expectations of actual revenues to be derived from those reserves nor their present worth. Assigning monetary values to the reserve quantity estimation process does not reduce the subjective and ever-changing nature of reserve estimates. Additional subjectivity occurs when determining present values because the rate of producing the reserves must be estimated. In addition to difficulty inherent in predicting the future,

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variations from the expected production rate could result from factors outside of our control, such as unintentional delays in development, environmental concerns or changes in prices or regulatory controls. Also, the reserve valuation assumes that all reserves will be disposed of by production. However, other factors such as the sale of reserves in place could affect the amount of cash eventually realized.

The December 31, 2012, future cash flows were computed by applying the unescalated 12-month average prices of $94.71 per barrel for oil, $43.14 per barrel for NGLs, and $2.76 per Mcf for natural gas, then adjusted for price differentials, relating to proved reserves and to the year-end quantities of those reserves. Future price changes are considered only to the extent provided by contractual arrangements in existence at year-end.

Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil, NGLs, and natural gas reserves at the end of the year, based on continuation of existing economic conditions.

Future income tax expenses are computed by applying the appropriate year-end statutory tax rates to the future pretax net cash flows relating to proved oil, NGLs, and natural gas reserves less the tax basis of our properties. The future income tax expenses also give effect to permanent differences and tax credits and allowances relating to our proved oil, NGLs, and natural gas reserves.

Care should be exercised in the use and interpretation of the above data. As production occurs over the next several years, the results shown may be significantly different as changes in production performance, petroleum prices and costs are likely to occur.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

(a) Evaluation of Disclosure Controls and Procedures
The company maintains “disclosure controls and procedures,” as that term is defined in Rule 13a-15(e) and Rule 15d-15(e) under the Securities Exchange Act of 1934 (the Exchange Act), that are designed to ensure that information required to be disclosed in reports the company files or submits under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms, and that such information is collected and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating its disclosure controls and procedures, our management recognized that no matter how well conceived and operated, disclosure controls and procedures can provide only reasonable, not absolute, assurance that the objectives of the disclosure controls and procedures are met. Our disclosure controls and procedures have been designed to meet, and our management believes that they meet, reasonable assurance standards. Based on their evaluation as of the end of the period covered by this Annual Report on Form 10-K, our Chief Executive Officer and Chief Financial Officer have concluded that, subject to the limitations noted above, the company’s disclosure controls and procedures were effective.

(b) Management’s Report on Internal Control Over Financial Reporting
Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as that is defined in Exchange Act Rule 13a-15(f). Our management, including our Chief Executive Officer and Chief Financial Officer, conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this evaluation, our management concluded that our internal control over

financial reporting was effective as of December 31, 2012.

The effectiveness of the company'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.

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(c) Changes in Internal Control Over Financial Reporting
During the last quarter, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

In accordance with Instruction G(3) of Form 10-K, the information required by this item is incorporated in this report by reference to the Proxy Statement, except for the information regarding our executive officers which is presented below. The Proxy Statement will be filed before our annual shareholders' meeting scheduled to be held on May 1, 2013.

Our Code of Ethics and Business Conduct applies to all directors, officers, and employees, including our Chief Executive Officer, our Chief Financial Officer, and our Controller. You can find our Code of Ethics and Business Conduct on our internet website, www.unitcorp.com. We will post any amendments to the Code of Ethics and Business Conduct, and any waivers that are required to be disclosed by the rules of either the SEC or the NYSE, on our internet website.

Because our common stock is listed on the NYSE, our Chief Executive Officer was required to make, and he has made, an annual certification to the NYSE stating that he was not aware of any violation of our corporate governance listing standards of the NYSE. Our Chief Executive Officer made his annual certification to that effect to the NYSE as of May 14, 2012. In addition, we have filed, as exhibits to this Annual Report on Form 10-K, the certifications of our Chief Executive Officer and Chief Financial Officer required under Section 302 of the Sarbanes-Oxley Act of 2002 to be filed with the SEC regarding the quality of our public disclosure.

Executive Officers

The table below and accompanying text sets forth certain information as of February 15, 2013 concerning each of our executive officers as well as certain officers of our subsidiaries. There were no arrangements or understandings between any of the officers and any other person(s) under which the officers were elected.

NAME	AGE	POSITION HELD
Larry D. Pinkston	58	Chief Executive Officer since April 1, 2005, Director since January 15, 2004, President since August 1, 2003, Chief Operating Officer since February 24, 2004, Vice President and Chief Financial Officer from May 1989 to February 24, 2004
Mark E. Schell	55	Senior Vice President since December 2002, General Counsel and Corporate Secretary since January 1987
David T. Merrill	52	Senior Vice President since May 2, 2012, Chief Financial Officer and Treasurer since February 24, 2004, Vice President of Finance from August 2003 to February 24, 2004
Brad J. Guidry	57	Executive Vice President, Unit Petroleum Company since March 1, 2005
John Cromling	65	Executive Vice President, Unit Drilling Company since April 15, 2005
Robert Parks	58	Manager and President, Superior Pipeline Company, L.L.C. since June 1996

Mr. Pinkston joined the company in December 1981. He had served as Corporate Budget Director and Assistant Controller before being appointed Controller in February, 1985. In December, 1986 he was elected Treasurer of the company and was elected to the position of Vice President and Chief Financial Officer in May, 1989. In August, 2003, he was elected to the position of President. He was elected a director of the company by the Board in January, 2004. In February, 2004, in addition to his position as President, he was elected to the office of Chief Operating Officer. In April 2005, he also began serving as Chief Executive Officer. Mr. Pinkston holds the offices of President, Chief Executive Officer, and Chief Operating Officer. He holds a Bachelor of Science Degree in Accounting from East Central University of Oklahoma.

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Mr. Schell joined the company in January 1987, as its Secretary and General Counsel. In 2003, he was promoted to Senior Vice President. From 1979 until joining Unit Corporation, Mr. Schell was Counsel, Vice President, and a member of the Board of Directors of C & S Exploration Inc. He received a Bachelor of Science degree in Political Science from Arizona State University and his Juris Doctorate degree from the University of Tulsa College of Law. He is a member of the Oklahoma Bar Association as well as the Association of Corporate Counsel. Mr. Schell is a director of the Oklahoma Independent Petroleum Association and is Chairman of its legal committee. In addition, he is the President and a director of the Oklahoma Injury Benefit Coalition, an Oklahoma non-profit association advocating for alternatives to Oklahoma's current Workers' Compensation system. He is also a member of the State Chamber of Oklahoma board of directors and serves on the board of advisors for the Greater Oklahoma City Chamber.

Mr. Merrill joined the company in August 2003 and served as its Vice President of Finance until February 2004 when he was elected to the position of Chief Financial Officer and Treasurer. In May 2012, he was promoted to Senior Vice President. From May 1999 through August 2003, Mr. Merrill served as Senior Vice President, Finance with TV Guide Networks, Inc. From July 1996 through May 1999 he was a Senior Manager with Deloitte & Touche LLP. From July 1994 through July 1996 he was Director of Financial Reporting and Special Projects for MAPCO, Inc. He began his career as an auditor with Deloitte, Haskins & Sells in 1983. Mr. Merrill received a Bachelor of Business Administration Degree in Accounting from the University of Oklahoma and is a Certified Public Accountant.

Mr. Guidry joined Unit Petroleum Company in August 1988 as a Staff Geologist. In 1991, he was promoted to Geologic Manager overseeing the Geologic Operations of the company. In January 2003, he was promoted to Vice President of the West division. In March 2005, Mr. Guidry was promoted to Senior Vice President of Exploration for Unit Petroleum Company. From 1979 to 1988, he was employed as a Division Geologist for Reading and Bates Petroleum Co. From 1978 to 1979, he worked with ANR Resources in Houston. He began his career as an open hole well logging engineer with Dresser Atlas Oilfield Services. Mr. Guidry graduated from Louisiana State University with a Bachelor of Science degree in Geology.

Mr. Cromling joined Unit Drilling Company in 1997 as a Vice-President and Division Manager. In April 2005, he was promoted to the position of Executive Vice-President of Drilling for Unit Drilling Company. In 1980, he formed Cromling Drilling Company which managed and operated drilling rigs until 1987. From 1987 to 1997, Cromling Drilling Company provided engineering consulting services and generated and drilled oil and natural gas prospects. Prior to this, he was employed by Big Chief Drilling for 11 years and served as Vice-President. Mr. Cromling graduated from the University of Oklahoma with a degree in Petroleum Engineering.

Mr. Parks founded Superior Pipeline Company, L.L.C. in 1996. When Superior was acquired by the company in July 2004, he continued with Superior as one of its managers and as its President. From April 1992 through April 1996 Mr. Parks served as Vice-President—Gathering and Processing for Cimarron Gas Companies. From December 1986 through March 1992, he served as Vice-President—Business Development for American Central Gas Companies. Mr. Parks began his career as an engineer with Cities Service Company in 1978. He received a Bachelor of Science degree in Chemical Engineering from Rice University and his M.B.A. from the University of Texas at Austin.

Item 11. Executive Compensation

In accordance with Instruction G(3) of Form 10-K, the information required by this Item is incorporated into this report by reference to the Proxy Statement (see Item 10 above).

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Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The following table provides information for all equity compensation plans as of the fiscal year ended December 31, 2012, under which our equity securities were authorized for issuance:

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)		Weighted Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (c)	
Equity compensation plans approved by security holders (1)	310,530	(2)	$43.17	1,975,661	(3)
Equity compensation plans not approved by security holders	—		—	—	
Total	310,530		$43.17	1,975,661	

(1) Shares awarded under all above plans may be newly issued, from our treasury or acquired in the open market.
(2) This number includes the following:
118,030 stock options outstanding under the company's Amended and Restated Stock Option Plan.
192,500 stock options outstanding under the Non-Employee Directors' Stock Option Plan.
(3) This number reflects the shares available for issuance under the Unit Corporation Stock and Incentive Compensation Plan Amended and Restated May 2, 2012 (the amended plan). The amended plan allows us to grant stock-based compensation to our employees and non-employee directors. The previous balance of 230,000 shares that were available for issuance under the Non-Employee Directors' Stock Option Plan were transferred to the amended plan on May 2, 2012. No more than 2,000,000 of the shares available under the amended plan may be issued as "incentive stock options" and all of the shares available under this plan may be issued as restricted stock. In addition, shares related to grants that are forfeited, terminated, canceled, expire unexercised, or settled in such manner that all or some of the shares are not issued to a participant shall immediately become available for issuance.

In accordance with Instruction G(3) of Form 10-K, the information required by this Item is incorporated into this report by reference to the Proxy Statement (see Item 10 above).

Item 13. Certain Relationships and Related Transactions, and Director Independence

In accordance with Instruction G(3) of Form 10-K, the information required by this Item is incorporated into this report by reference to the Proxy Statement (see Item 10 above).

Item 14. Principal Accounting Fees and Services

In accordance with Instruction G(3) of Form 10-K, the information required by this Item is incorporated into this report by reference to the Proxy Statement (see Item 10 above).

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PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) Financial Statements, Schedules and Exhibits:

1. Financial Statements:

Included in Part II of this report:

Report of Independent Registered Public Accounting Firm
Consolidated Balance Sheets as of December 31, 2012 and 2011
Consolidated Statements of Income for the years ended December 31, 2012, 2011, and 2010
Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2012, 2011, and 2010
Consolidated Statements of Changes in Shareholders’ Equity for the years ended December 31, 2010, 2011, and 2012
Consolidated Statements of Cash Flows for the years ended December 31, 2012, 2011, and 2010
Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

Included in Part IV of this report for the years ended December 31, 2012, 2011, and 2010:

Schedule II—Valuation and Qualifying Accounts and Reserves

Other schedules are omitted because of the absence of conditions under which they are required or because the required information is included in the consolidated financial statements or notes thereto.

3. Exhibits:

The exhibit numbers in the following list correspond to the numbers assigned such exhibits in the Exhibit Table of Item 601 of Regulation S-K.

3.1	Restated Certificate of Incorporation of Unit Corporation (filed as Exhibit 3.1 to Unit's Form 8-K, dated June 29, 2000, which is incorporated herein by reference).
3.1.2	Certificate of Amendment of Amended and Restated Certificate of Incorporation of the Company (filed as Exhibit 3.1 to Unit’s Form 8-K, dated May 9, 2006 which is incorporated herein by reference).
3.2	By-Laws of Unit Corporation as amended and restated May 7, 2008 (filed as Exhibit 3.2 to Unit’s Form 8-K, dated May 8, 2008 which is incorporated herein by reference).
4.1	Form of Common Stock Certificate (filed as Exhibit 4.1 to Unit’s Form S-3 (File No. 333-83551), which is incorporated herein by reference).
4.2	Rights Agreement as amended and restated on May 18, 2005 (filed as Exhibit 4.1 to Unit’s Form 8-K dated May 18, 2005, which is incorporated herein by reference).
4.3	Amendment to Rights Agreement dated March 24, 2009 (filed as Exhibit 4.1 to Unit’s Form 8-K dated March 23, 2009, which is incorporated herein by reference).

4.4	Standstill Agreement dated March 24, 2009, by and between us and the George Kaiser Foundation (filed as Exhibit 4.2 to Unit’s Form 8-K dated March 23, 2009, which is incorporated herein by reference).
4.5	Indenture dated as of May 18, 2011, by and between the Company and Wilmington Trust FSB, as trustee (filed as Exhibit 4.1 to Unit’s Form 8-K dated May 18, 2011, which is incorporated herein by reference).
4.6	First Supplemental Indenture (including form of note) dated as of May 18, 2011, by and among the Company, as issuer, the Subsidiary Guarantors (as defined therein), as guarantors and Wilmington Trust FSB as trustee (filed as Exhibit 4.1 to Unit’s Form 8-K dated May 18, 2011, which is incorporated herein by reference).

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4.7	Indenture dated July 24, 2012, among Unit Corporation, certain of its wholly-owned subsidiaries party thereto, as guarantors, and Wilmington Trust, National Association, as trustee (filed as Exhibit 4.1 to Unit's Form 8-K dated July 24, 2012, which is incorporated herein by reference).
4.8	First Supplemental Indenture (including form of note) dated July 24, 2012, among Unit Corporation, certain of its wholly-owned subsidiaries party thereto, as guarantors, and Wilmington Trust, National Association, as trustee (filed as Exhibit 4.2 to Unit's Form 8-K dated July 24, 2012, which is incorporated herein by reference).
4.9	Registration Rights Agreement dated July 24, 2012, among Unit Corporation, certain of its wholly-owned subsidiaries party thereto, as guarantors, and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as the representative of the several initial purchasers (filed as Exhibit 4.3 to Unit's Form 8-K dated July 24, 2012, which is incorporated herein by reference).
10.1.1	Third Amended and Restated Security Agreement effective November 1, 2005 (filed as Exhibit 10.2 to Unit's Form 8-K dated November 4, 2005, which is incorporated herein by reference).
10.1.2*	Form of Unit Corporation Restricted Stock Bonus Agreement (filed as Exhibit 10.1 to Unit's Form 8-K dated December 13, 2005, which is incorporated herein by reference).
10.1.3*	Unit Corporation Stock and Incentive Compensation Plan Amended and Restated May 2, 2012 (filed as Exhibit 10 to Unit's Form 8-K dated May 2, 2012, which is incorporated herein by reference).
10.1.4	Consulting Agreement with John G. Nikkel dated June 1, 2010 (filed as Exhibit 10.1 to Unit's Form 8-K dated June 30, 2010, which is incorporated herein by reference).
10.1.5	Amended and Restated Key Employee Change of Control Contract dated August 19, 2008 (filed as Exhibit 10.1 to Unit's Form 8-K dated August 25, 2008, which is incorporated herein by reference).
10.1.6	Senior Credit Agreement dated September 13, 2011 by and among the Company and the subsidiaries named therein (as borrowers), BOKF, NA DBA Bank of Oklahoma, as Administrative Agent, and the institutions named therein (as lenders) (filed as Exhibit 10.1 to Unit's Form 8-K dated September 13, 2011, which is incorporated herein by reference).
10.1.7	Gas Purchase Agreement dated November 21, 2011 by and between Superior Pipeline Company, L.L.C. and Sullivan and Company, L.L.C. (filed as Exhibit 10.1 to Unit's Form 8-K dated November 21, 2011, which is incorporated herein by reference).
10.1.8	First Amendment and Consent, dated September 5, 2012, to the Senior Credit Agreement by and among the Company and the subsidiaries named therein (as borrowers), BOKF, NA DBA Bank of Oklahoma, as Administrative Agent, and the institutions named therein (as lenders) (filed as exhibit 10.1 to Unit's Form 8-K dated September 5, 2012, which is incorporated herein by reference).
10.2.1	Unit 1979 Oil and Gas Program Agreement of Limited Partnership (filed as Exhibit I to Unit Drilling and Exploration Company's Registration Statement on Form S-1 as S.E.C. File No. 2-66347, which is incorporated herein by reference).
10.2.2	Unit 1984 Oil and Gas Program Agreement of Limited Partnership (filed as an Exhibit 3.1 to Unit 1984 Oil and Gas Program's Registration Statement Form S-1 as S.E.C. File No. 2-92582, which is incorporated

	herein by reference).
10.2.3*	Unit’s Amended and Restated Stock Option Plan (filed as an Exhibit to Unit’s Registration Statement on Form S-8 as S.E.C. File No’s. 33-19652, 33-44103, 33-64323 and 333-39584 which is incorporated herein by reference).
10.2.4*	Unit Corporation Non-Employee Directors’ Stock Option Plan (filed as an Exhibit to Form S-8 as S.E.C. File No. 33-49724 and File No. 333-166605, which are incorporated herein by reference).
10.2.5*	Unit Corporation Employees’ Thrift Plan (filed as an Exhibit to Form S-8 as S.E.C. File No. 33-53542, which is incorporated herein by reference).
10.2.6	Unit Consolidated Employee Oil and Gas Limited Partnership Agreement (filed as an Exhibit to Unit’s Annual Report under cover of Form 10-K for the year ended December 31, 1993, which is incorporated herein by reference).
10.2.7*	Unit Corporation Salary Deferral Plan (filed as an Exhibit to Unit’s Annual Report under cover of Form 10-K for the year ended December 31, 1993, which is incorporated herein by reference).
10.2.8*	Unit Corporation Separation Benefit Plan for Senior Management as amended (filed as an Exhibit 10.1 to Unit’s Form 8-K dated December 20, 2004).

10.2.9*	Unit Corporation Special Separation Benefit Plan as amended (filed as Exhibit 10.3 to Unit's Form 8-K dated December 20, 2004).
10.2.10	Unit 2000 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under the cover of Form 10-K for the year ended December 31, 1999).
10.2.11*	Unit Corporation 2000 Non-Employee Directors' Stock Option Plan (filed as an Exhibit to Form S-8 as S.E.C. File No. 333-38166, which is incorporated herein by reference).
10.2.12	Unit 2001 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under the cover of Form 10-K for the year ended December 31, 2000).
10.2.13	Unit 2002 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2001).
10.2.14	Unit 2003 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2002).
10.2.15	Unit 2004 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2003).
10.2.16	Unit 2005 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2004).
10.2.17*	Form of Indemnification Agreement entered into between the Company and its executive officers and directors (filed as Exhibit 10.1 to Unit's Form 8-K dated February 22, 2005, which is incorporated herein by reference).
10.2.18	Unit 2006 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2005).
10.2.19	Unit 2007 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2006).
10.2.20*	Separation Benefit Plan as amended August 21, 2007 (filed as an Exhibit to Unit's Form 10-Q for the quarter ended September 30, 2007).
10.2.21	Unit 2008 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2007).
10.2.22*	Annual Bonus Performance Plan entered into October 21, 2008 (filed as Exhibit 10.1 to Unit's Form 8-K dated October 23, 2008, which is incorporated herein by reference).
10.2.23*	Separation Benefit Plan as amended October 21, 2008 (filed as Exhibit 10.2 to Unit's Form 8-K dated October 23, 2008, which is incorporated herein by reference).
10.2.24*	Separation Benefit Plan as amended December 31, 2008 (filed as Exhibit 10.1 to Unit's Form 8-K dated January 6, 2009, which is incorporated herein by reference).

10.2.25*	Special Separation Benefit Plan as amended December 31, 2008 (filed as Exhibit 10.2 to Unit's Form 8-K dated January 6, 2009, which is incorporated herein by reference).
10.2.26*	Separation Benefit Plan for Senior Management as amended December 31, 2008 (filed as Exhibit 10.3 to Unit's Form 8-K dated January 6, 2009, which is incorporated herein by reference).
10.2.27	Unit 2009 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2008).
10.2.28*	Unit Corporation 2000 Non-Employee Directors' Stock Option Plan as Amended and Restated August 25, 2004 (as amended on May 29, 2009 and filed as Exhibit 10.1 to Unit's Form 8-K dated May 29, 2009, which is incorporated herein by reference).
10.2.29	Unit 2010 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2009).
10.2.30	Unit 2011 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2010).
21	Subsidiaries of the Registrant (filed herein).

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23.1	Consent of Independent Registered Public Accounting Firm, PricewaterhouseCoopers LLP (filed herein).
23.2	Consent of Ryder Scott Company, L.P. (filed herein).
31.1	Certification of Chief Executive Officer under Rule 13a - 14(a) of the Exchange Act (filed herein).
31.2	Certification of Chief Financial Officer under Rule 13a - 14(a) of the Exchange Act (filed herein).
32	Certification of Chief Executive Officer and Chief Financial Officer under Rule 13a-14(a) of the Exchange Act and 18 U.S.C. Section 1350, as adopted under Section 906 of the Sarbanes-Oxley Act of 2002 (filed herein).
99.1	Ryder Scott Company, L.P. Summary Report (filed herein).
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

* Indicates a management contract or compensatory plan identified under the requirements of Item 15 of Form 10-K.

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Schedule II
UNIT CORPORATION AND SUBSIDIARIES
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Allowance for Doubtful Accounts:

Description	Balance at Beginning of Period	Additions Charged to Costs & Expenses	Deductions & Net Write-Offs	Balance at End of Period
	(In thousands)			
Year ended December 31, 2012	$5,343	$90	$(90)	$5,343
Year ended December 31, 2011	$5,083	$260	$—	$5,343
Year ended December 31, 2010	$5,186	$—	$(103)	$5,083

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SIGNATURES

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

UNIT CORPORATION

DATE: February 26, 2013 By:	/s/ LARRY D. PINKSTON LARRY D. PINKSTON President and Chief Executive Officer (Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on the 26th day of February, 2013.

Name	Title
/s/ JOHN G. NIKKEL John G. Nikkel	Chairman of the Board and Director
/s/ LARRY D. PINKSTON Larry D. Pinkston	President and Chief Executive Officer, Chief Operating Officer and Director (Principal Executive Officer)
/s/ DAVID T. MERRILL David T. Merrill	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ DON A. HAYES Don A. Hayes	Vice President, Controller (Principal Accounting Officer)
/s/ J. MICHAEL ADCOCK J. Michael Adcock	Director
/s/ GARY CHRISTOPHER Gary Christopher	Director
/s/ STEVEN B. HILDEBRAND Steven B. Hildebrand	Director
/s/ WILLIAM B. MORGAN William B. Morgan	Director
/s/ LARRY C. PAYNE Larry C. Payne	Director
/s/ G. BAILEY PEYTON IV G. Bailey Peyton IV	Director
/s/ ROBERT SULLIVAN, JR. Robert Sullivan, Jr.	Director

/s/ JOHN H. WILLIAMS John H. Williams	Director

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EXHIBIT INDEX

Exhibit No.	Description
21	Subsidiaries of the Registrant.
23.1	Consent of Independent Registered Public Accounting Firm, PricewaterhouseCoopers LLP.
23.2	Consent of Ryder Scott Company, L.P.
31.1	Certification of Chief Executive Officer under Rule 13a—14(a) of the Exchange Act.
31.2	Certification of Chief Financial Officer under Rule 13a—14(a) of the Exchange Act.
32	Certification of Chief Executive Officer and Chief Financial Officer under Rule 13a-14(a) of the Exchange Act and 18 U.S.C. Section 1350, as adopted under Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Ryder Scott Company, L.P. Summary Report.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.