UNIT CORP
Form 10-K
February 23, 2012
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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, 2011

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, 2011, 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, 2011) held by non-affiliates was approximately $1,759,458,732. 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 10, 2012
Common Stock, $0.20 par value per share	48,247,040 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 2, 2012. 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 124

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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 to six Mcf of natural gas.

Bbl Barrel, or 42 U.S. gallons liquid volume.

Boe Barrel of oil equivalent.

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.

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DEFINITIONS (Continued)

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 and oil property with existing production.

Proved developed reserves Are reserves from any category 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 is by means not involving a well. 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 indicated 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 Is 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, coal bed or 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 stimulation treatments or other special recovery processes in order to produce economically.

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DEFINITIONS (Continued)

Undeveloped acreage Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial 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, 2011

PART I

Item 1. Business

Unless otherwise indicated or required by the context, the terms corporation , company , Unit , us , our , we and its refer to Unit Corporat 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, or at 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 Nomination 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 relations section of our website, as allowed by SEC rules.

GENERAL

We were founded in 1963 as a 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 10, 2012:

Number of drilling rigs owned	127

Completed gross wells in which we own an interest	8,823
Number of natural gas treatment plants owned	3
Number of processing plants owned	10
Number of natural gas gathering systems owned	35

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2011 SEGMENT OPERATION HIGHLIGHTS

Contract Drilling

- Averaged 76.1 drilling rigs used, an increase of 24% over the average of 61.4 drilling rigs used during 2010.
- Built seven new 1,500 horsepower, diesel-electric drilling rigs for our Rocky Mountain division. Five were placed in service in the Bakken Shale in North Dakota, one was placed in service in Western Wyoming and the other one is to be placed into service in Western Wyoming in the first quarter of 2012.
- During the year, 19 of our drilling rigs were either refurbished, upgraded or returned into service after previously being stacked for use to meet increasing horizontal drilling activity.

Oil and Natural Gas

- Attained net proved oil, natural gas liquids (NGLs) and natural gas reserves of 116.0 million barrels of oil equivalents (MMBoe), a 12% increase over end of 2010 reserves.
- Increased net proved oil and NGL reserves 26% over 2010.
- Total production of 12.1 MMBoe or 23% over 2010.
- Participated in the drilling of 160 wells.
- Acquired 12,000 net held by production acres, 30 operated wells and 59 non-operated wells located mainly in Harper, Ellis and Beaver Counties, Oklahoma from certain unaffiliated third parties.
- Acquired 55,000 net acres (96% of which is held by production) and 500 wells located principally in the Oklahoma Arkoma, Woodford and Hartshorne Coal plays along with other properties from certain unaffiliated third parties.

Mid-Stream

- Gas processed increased 41% over 2010.
- Completed construction of a new gathering system and gas processing plant in Grant County, Oklahoma.
- Completed the construction of a16-mile, 16 pipeline and accompanying compressor station in Preston County, West Virginia.

Added an additional 74 miles of pipeline (approximately a 9% increase) and connected 62 new wells to its gathering systems.

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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.

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, Wyoming, Colorado, Utah, Montana and North Dakota.

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

	Year Ended December 31,		
	2011	**2010**	**2009**
Number of drilling rigs owned at end of year	127.0	121.0	130.0
Average number of drilling rigs owned during year	123.7	123.9	130.8
Average number of drilling rigs utilized	76.1	61.4	38.9
Utilization rate (1)	61%	50%	30%
Average revenue per day (2)	$ 17,455	$ 14,115	$ 16,662
Total footage drilled (feet in 1,000 s)	9,749	7,961	4,627
Number of wells drilled	742	593	409

(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 from our contract drilling operations divided by the total number of days our drilling rigs were used 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 that are collectively unitized into an operating system commonly referred to as a drilling rig. 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 2011, 85 of our 127 drilling rigs were used in drilling services.

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The following table shows certain information about our drilling rigs (including their distribution) as of February 10, 2012:

Region	Contracted Rigs	Non-Contracted Rigs	Total Rigs	Average Rated Drilling Depth (ft)
Anadarko Basin Oklahoma and Texas Panhandle	49	25	74	16,142
Arkoma Basin	2	3	5	13,900
East Texas, Louisiana, Gulf				
Coast and South Texas	11	7	18	17,611
Rocky Mountains	21	9	30	18,100
Totals	83	44	127	16,724

With the downturn in drilling activity that started in the fourth quarter of 2008, we consolidated our nine operating divisions into six at the beginning of 2009 to minimize our costs. Currently our operating divisions consist of the following: Arkoma, Gulf Coast, Mid-Continent, Panhandle, Rocky Mountain and Woodward.

Drilling rig utilization steadily increased throughout 2010 and 2011. In the middle of 2009 our active rig count reached a low of 28 rigs. Our active rig count at the beginning of 2010 was 42 rigs and increased to 82 rigs to finish out 2011.

Anadarko Basin. The Anadarko Basin is a geologic feature covering approximately 50,000 square miles primarily in Central and Western Oklahoma, but also includes the upper Texas Panhandle, southwestern Kansas and southeastern Colorado region. The basin contains sedimentary deposits ranging in thickness from 2,000 feet on its northern and western flanks to 40,000 feet in its southern portion.

During 2011, our Mid-Continent, Panhandle and Woodward divisions working in the Anadarko Basin area averaged 24.0, 9.1 and 8.9 drilling rigs operating, respectively. Part of the increased activity in this area stems from the oil and NGL interest by operators working primarily in the Cana Woodford , Granite Wash, Marmaton and Mississippi horizontal plays.

Arkoma Basin. The Arkoma Basin is another geologic feature that encompasses approximately 33,800 square miles of southeastern Oklahoma and west-central Arkansas. The Arkoma Basin holds deposits ranging in thickness from 3,000 to 20,000 feet. It contains multiple conventional gas plays as well as two of the more recent notable unconventional plays the Woodford Shale and Fayetteville Shale.

During 2011, our Arkoma division averaged 3.6 drilling rigs operating. The Arkoma Basin has traditionally been a natural gas play. With lower natural gas commodity prices during 2011 and operators shifting their drilling emphasis to liquids, we moved one rig from this division to our Mid-Continent division for greater utilization. Additionally, we reactivated two stacked, lower horsepower rigs and moved into southern Oklahoma drilling oil and liquids rich programs.

East Texas, Louisiana, Gulf Coast and South Texas. Our Gulf Coast division provides drilling rigs to the onshore areas of the south Louisiana Gulf Coast and upper Texas Gulf Coast region as well as the conventional and unconventional gas plays of northwest Louisiana, East Texas and South Texas. The Gulf Coast division averaged 12.9 drilling rigs operating for the year. The Haynesville Shale play was an active area for us with six rigs working there during most of 2011. As natural gas prices declined in 2011, rig activity in the Haynesville Shale began to slow and we moved four rigs out of this area, two were relocated to the Mid-Continent division, one relocated to South Texas and one was recently relocated to the Arkoma division. At year-end 2011, we had two rigs operating in the Haynesville area and six rigs in the Eagle Ford area.

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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 17.6 drilling rigs during 2011. We have drilling rigs operating primarily in the Pinedale Anticline of western Wyoming and the Bakken Shale of North Dakota, as well as other areas throughout this expansive geographical area. We ended 2011 with 14 drilling rigs working in the Bakken Shale, including six new build rigs that were constructed and placed into service during 2011. Additionally, one new 1,500 horsepower electric drilling rig is rigging up to begin operations during the first quarter of 2012. As mentioned earlier, we are in the process of building another 1,500 horsepower electric drilling rig that will be deployed in the second quarter of 2012 to the Bakken Shale.

At any given time the number of our drilling rigs we can work is dependent 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 various conditions tends to fluctuate with the demand for our drilling rigs. Our utilization rate was significantly affected by the U.S. and world economic downturn starting in late 2008. For 2009, our average utilization rate declined to 30%, for 2010 our average utilization rate increased to 50%, and by 2011 it was 61%.

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

	2011	2010	2009
First quarter	70.0	50.9	52.8
Second quarter	73.1	58.1	31.6
Third quarter	78.9	65.4	34.6
Fourth quarter	82.1	70.9	36.7

Drilling Rig Fleet. The following table summarizes the changes made to our drilling rig fleet in 2011. A more complete discussion of these changes follows the table:

Drilling rigs owned at December 31, 2010	121
Drilling rigs sold	
Drilling rigs purchased	
Drilling rigs constructed	6
Total drilling rigs owned at December 31, 2011	127

Dispositions, Acquisitions, and Construction. During 2009, we sold three mechanical drilling rigs (ranging in horsepower from 750 to 1,000) for $8.6 million and recorded a $4.8 million gain and acquired one new 1,500 horsepower diesel electric drilling rig for $13.2 million.

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 of those drilling rigs 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 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 working in the Bakken shale in North Dakota under two-year drilling contracts.

During the third quarter of 2011, we were awarded two additional new build rig contracts for 1,500 horsepower, diesel-electric drilling rigs. These new build rigs will initially be working under three year contracts. One was placed into service during the fourth quarter of 2011 and the other will be placed in service during the first quarter of 2012.

During the fourth quarter of 2011, we entered into an agreement to build a new 1,500 horsepower, diesel-electric drilling rig to be used in North Dakota starting in the second quarter of 2012. This new build rig will initially be working under a three year contract.

Subsequent to the 2011 year-end, we sold an idle 600 horsepower mechanical drilling rig to an unaffiliated third party.

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 93% of our working drilling rigs are drilling for oil or NGLs. Of those, approximately 98% 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 with 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 2011, we drilled four wells under a footage contract in 2010 and one well in 2009. 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.

Under turnkey contracts 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 2011, QEP Resources, Inc. was our largest drilling customer accounting for approximately 22% of our total contract drilling revenues. Our work for this customer 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 2011, 2010 and 2009, we drilled 81, 75 and 38 wells, respectively, or 11%, 13% and 9%, 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 $52.2 million, $40.1 million and $15.0 million during 2011, 2010 and 2009, respectively from our contract drilling segment and eliminated the associated operating expense of $32.6 million, $31.0 and $13.7 million during 2011, 2010 and 2009, respectively, yielding $19.6 million, $9.1 million and $1.3 million during 2011, 2010 and 2009, 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, Texas, Louisiana, North Dakota and, to a lesser extent, in Arkansas, New Mexico, Wyoming, Montana, Alabama, Kansas, Mississippi, Michigan, Colorado and Pennsylvania 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.

The following table presents certain information regarding our oil and natural gas operations as of December 31, 2011:

					2011 Average Net Daily Production		
Our Divisions/Area	**Number of Gross Wells**	**Number of Net Wells**	**Number of Gross Wells in Process**	**Number of Net Wells in Process**	**Natural Gas (Mcf)**	**Oil (Bbls)**	**NGL (Bbls)**
West division (consists principally of the Rocky Mountain region, New Mexico, Western and Southern Texas and the Gulf Coast region)	3,308	534.37	11	5.60	32,258	2,446	2,186
East division (consists principally of the Appalachian region, Arkansas, East Texas, Northern Louisiana and Eastern Oklahoma)	1,697	526.32	2	0.46	34,979	33	14
Central division (consists principally of Kansas, Western Oklahoma and the Texas Panhandle)	3,806	986.07	13	4.46	53,596	4,401	3,934
Total	8,811	2,046.76	26	10.52	120,833	6,880	6,134

As of December 31, 2011, we did not have any significant water floods, pressure maintenance operations, or any other material operations that were in process.

Description and Location of Our Core Operations

West division. Our Wilcox play, located primarily in Polk, Tyler and Hardin Counties, Texas, continues to grow. For 2011, we operated and completed 17 wells with an average working interest of 97%. The net production from this area for the fourth quarter 2011 averaged 1,562 barrels of oil per day, 1,486 barrels of NGLs per day and 24.5 MMcf per day, or an equivalent rate of 42.7 MMcfe per day, an increase of 34% from the fourth quarter of 2010. For 2012, we plan to drill approximately 15 gross wells with an approximate working interest of 87% for an estimated cost of $41 million. We hold approximately 26,000 net leasehold acres in the Wilcox play. We have entered into a development agreement covering approximately 47,000 net mineral acres and have acquired lease options covering approximately 82,000 net mineral acres in the expanded area.

In the Bakken play located in North Dakota, we participated in 17 wells in 2011 at an average working interest of 11% and a total net cost of approximately $18 million. The average ultimate recovery for a Bakken horizontal well is estimated to be 662 thousand barrels of oil equivalent (MBoe) per well. The net production from our Bakken play for the fourth quarter 2011 averaged approximately 831 barrels of oil per day and 977 Mcf per day, an increase of 42% from the fourth quarter of 2010. For 2012, we anticipate participating in approximately 20 gross wells with an average working interest of 10% to 15% at a total net cost of approximately $30 million. We own approximately 13,400 net acres in the play and anticipate two to three rigs drilling on its North Dakota Bakken leasehold during 2012.

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. During 2011, we drilled 34 wells with an average working interest of 87% in our Marmaton horizontal oil play located in Beaver County, Oklahoma. The initial 30-day average production rate for the 34 wells ranged from 20 barrels of oil equivalent (Boe) per day to 930 Boe per day with an average rate of 308 Boe per day. The average ultimate recovery for a Marmaton horizontal well is estimated to be 130 MBoe, which is comprised of approximately 78% oil, 14% NGLs and 8% natural gas. The average completed well cost is approximately $2.7 million. The net production from our Marmaton operated wells for the fourth quarter 2011 averaged 2,295 barrels of oil per day, 321 barrels NGLs per day, and 1,077 Mcf per day, an increase of 46% over the third quarter 2011 and a 176% increase over the fourth quarter 2010. For 2012, we anticipate running a two drilling rig program in this play that should result in 30 to 35 gross wells at an approximate net cost of $61 million to $71 million. We plan to drill our first 9,000 extended lateral in this play during the first quarter of 2012 for an estimated cost of $4.2 million. The average lateral length drilled to date is 4,100 feet. We currently have leases on approximately 92,262 net acres in this play.

In our Granite Wash (GW) play located in the Texas Panhandle, we drilled and operated 16 horizontal wells with an average working interest of 76% during 2011. The 30-day average production rate for the 16 wells was 6.8 MMcfe per day. The GW laterals completed in 2011 targeted six different GW sands with 44% of the laterals drilled in the GW B interval. The average ultimate recovery for a GW horizontal well is estimated to be 4.6 Bcfe, which is comprised of 13% oil, 37% NGLs and 50% natural gas. The average completed well cost is approximately $5.5 million. The net production from our GW operated wells for the fourth quarter 2011 averaged 1,136 barrels of oil per day, 3,065 barrels NGLs per day and 24.8 MMcf per day, or an equivalent rate of 50.5 MMcfe per day, an increase of 2% over the third quarter 2011 and a 59% increase over the fourth quarter 2010. We expect to work three to four Unit drilling rigs drilling horizontal wells in 2012 which equates to approximately 20 operated GW wells with an approximate net cost of $90 million.

We have recently acquired approximately 60,000 net acres located primarily in south central Kansas in the developing Mississippian play. The current plans are to drill three to four horizontal wells in the next six months and evaluate the results before planning any further drilling in this play.

Dispositions and Acquisitions. There were no material dispositions during 2011 or 2010.

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. At the time of acquisition, proved developed producing net reserves associated with the 10 acquired producing wells was approximately 762,000 BOE consisting of 511,000 barrels of oil, 155,000 barrels of NGLs and 573 MMcf of natural gas.

Also during the second quarter of 2010, we completed an acquisition from unaffiliated parties consisting of approximately 32,000 net acres of undeveloped oil and gas leasehold located in Southwest Oklahoma and North Texas for approximately $17.6 million.

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 in Oklahoma and Lipscomb County, Texas. The purchase price allocation was $8.4 million for proved properties and $3.9 million for acreage. The net proved developed reserves associated with the acquisition are estimated at 6.6 Bcfe (91% natural gas) with production of 1.7 MMcfe per day. 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, subject to closing adjustments, 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 proved reserves associated with the acquisition are approximately 31.2 Bcfe (99% natural gas), 83% of which is proved developed. The acquisition also included approximately 55,000 net acres of which 96% is held by production.

During the fourth quarter of 2011, we leased approximately 60,000 net acres of undeveloped oil and gas leasehold located in south central Kansas for approximately $17.3 million.

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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,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Wells drilled:						
Exploratory:						
Oil:						
West division	0	0	3	1.41	2	0.28
East division	0	0	0	0	0	0
Central division	0	0	1	1.00	0	0
Total oil	0	0	4	2.41	2	0.28
Natural gas:						
West division	5	4.13	4	4.00	3	2.50
East division	0	0	0	0	0	0
Central division	0	0	1	0.05	0	0
Total natural gas	5	4.13	5	4.05	3	2.50
Dry:						
West division	7	6.50	5	4.12	3	2.10
East division	0	0	0	0	0	0
Central division	0	0	0	0	0	0
Total dry	7	6.50	5	4.12	3	2.10
Total exploratory	12	10.63	14	10.58	8	4.88
Development:						
Oil:						
West division	21	4.57	25	4.69	14	3.54
East division	0	0	0	0	0	0
Central division	56	32.81	43	25.90	6	1.80
Total oil	77	37.38	68	30.59	20	5.34
Natural gas:						
West division	9	6.26	13	10.85	1	1.00
East division	9	4.65	19	11.47	35	16.96
Central division	44	18.32	42	18.22	28	12.77
Total natural gas	62	29.23	74	40.54	64	30.73
Dry:						
West division	3	2.03	4	1.51	1	0.80
East division	1	1.00	1	0.36	1	0.16
Central division	5	2.15	6	3.94	1	0.60
Total dry	9	5.18	11	5.81	3	1.56

Total development	148	71.79	153	76.94	87	37.63
Total wells drilled	160	82.42	167	87.52	95	42.51

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	Year Ended December 31, 2011 Gross	2011 Net	2010 Gross	2010 Net	2009 Gross	2009 Net
Wells producing or capable of producing:						
Oil:						
West division	2,074	183.50	2,052	178.85	2,051	178.85
East division	54	3.17	52	2.58	52	2.75
Central division	631	273.31	552	234.05	552	227.73
Total oil	2,759	459.98	2,656	415.48	2,655	409.33
Natural gas:						
West division	1,182	335.90	1,167	324.33	1,128	314.37
East division	1,636	522.15	1,086	290.04	1,052	266.04
Central division	3,097	683.08	2,927	611.05	2,868	580.57
Total natural gas	5,915	1,541.13	5,180	1,225.42	5,048	1,160.98
Total	8,674	2,001.11	7,836	1,640.90	7,703	1,570.31

As of February 10, 2012, we had participated in 12 gross (7.33 net) wells started during 2012.

Cost incurred for development drilling includes $111.4 million, $84.6 million and $24.5 million in 2011, 2010 and 2009, respectively, to develop booked proved undeveloped oil and natural gas reserves.

The following table summarizes our leasehold acreage at December 31, 2011:

	Year Ended December 31, 2011 Developed Gross	Developed Net	Undeveloped Gross	Undeveloped Net (1)	Total Gross	Total Net
West division	318,063	104,221	208,615	113,158	526,678	217,379
East division	266,693	113,720	218,531	68,230	485,224	181,950
Central division	660,656	217,946	228,374	161,776	889,030	379,722
Total	1,245,412	435,887	655,520	343,164	1,900,932	779,051

(1) Approximately 83% (West 67%; East 83% and Central 94%) of the net undeveloped acres are covered by leases that will expire in the years 2012 2014 unless drilling or production extends the terms of those leases.

The future estimated development costs necessary to develop our proved undeveloped oil and natural gas reserves in the United States for the years 2012 2016, as disclosed in our December 31, 2011 oil and natural gas reserve report, are $159.1 million, $124.9 million, $7.4 million, $2.8 million and $1.0 million, respectively.

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Price and Production Data. The following tables identify the average sales price, oil, NGLs and natural gas 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,		
	2011	**2010**	**2009**
Average sales price per barrel of oil produced:			
Price before hedging	$ 93.49	$ 76.65	$ 56.64
Effect of hedging	(6.31)	(7.13)	(0.31)
Price including hedging	$ 87.18	$ 69.52	$ 56.33
Average sales price per barrel of NGLs produced:			
Price before hedging	$ 44.44	$ 36.96	$ 25.66
Effect of hedging	(0.80)	0.08	(2.85)
Price including hedging	$ 43.64	$ 37.04	$ 22.81
Average sales price per Mcf of natural gas produced:			
Price before hedging	$ 3.78	$ 4.05	$ 3.26
Effect of hedging	0.48	1.57	2.33
Price including hedging	$ 4.26	$ 5.62	$ 5.59

	Year Ended December 31,		
	2011	2010	2009
Oil production (MBbls):			
West division	893	729	648
East division	12	14	13
Central division:			
Mendota field	262	149	138
All other central division fields	1,344	629	487
Total central division	1,606	778	625
Total oil production (MBbls)	2,511	1,521	1,286
NGL production (MBbls):			
West division	798	627	699
East division	5	4	5
Central division:			
Mendota field	691	494	475
All other central division fields	745	424	309
Total central division	1,436	918	784
Total NGL production (MBbls)	2,239	1,549	1,488
Natural gas production (MMcf):			
West division	11,774	10,946	12,395
East division	12,768	14,029	14,639
Central division:			
Mendota field	4,887	4,050	4,227
All other central division fields	14,675	11,731	12,802
Total central division	19,562	15,781	17,029
Total natural gas production (MMcf)	44,104	40,756	44,063
Total production (MBoe):			
West division	3,653	3,180	3,412
East division	2,145	2,356	2,458
Central division:			
Mendota field	1,768	1,318	1,318
All other central division fields	4,535	3,009	2,930
Total central division	6,303	4,327	4,248
Total production (MBoe)	12,101	9,863	10,118
Average production cost per equivalent Bbl	$ 9.54	$ 9.24	$ 8.70

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

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

	Year Ended December 31, 2011			
	Natural Gas (MMcf)	Oil (MBbls)	NGL (MBbls)	Total Proved Reserves (MBoe)
Proved developed:				
West division	70,299	5,490	4,403	21,610
East division	131,883	87	70	22,137
Central division	170,129	10,041	12,176	50,572
Total proved developed	372,311	15,618	16,649	94,319
Proved undeveloped:				
West division	6,031	2,214	306	3,525
East division	14,841	0	0	2,473
Central division	48,952	2,423	5,132	15,714
Total proved undeveloped	69,824	4,637	5,438	21,712
Total proved	442,135	20,255	22,087	116,031

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 comprised the top 82% of the total proved developed discounted future net income and 96% 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, 2011.

Our Reservoir Engineering department is responsible for reserve determination for all wells in which we have an interest. Their primary objective is to estimate our future reserves and their 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 and the company s internal audit group has a checklist of review tasks to confirm the correctness of 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 was the primary technical person designated to be in charge on behalf of Ryder Scott for our audit of reserves.

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

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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.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Richoux fulfills. As part as his 2011 continuing education hours, Mr. Richoux attended 29 hours of formalized in-house and external training.

Based on his educational background, professional training and more than 40 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Richoux has attained the professional qualifications as a Reserve Estimator [requires appropriate degree and/or is registered as Professional Engineer and has a minimum of three years experience in the estimation and evaluation of reserves] and Reserve Auditor [requires appropriate degree and/or is registered as Professional Engineer and has a minimum of 10 years experience in the estimation and evaluation of reserves of which at least five 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.

Unit Corporation Responsibility for overseeing the preparation of the company s reserve report is shared by its 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 the recent changes that have occurred in SEC rules pertaining to 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 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 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.

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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 (LKH) 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 (HKO) elevation and the potential exist 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.

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 shall be the average price during the 12-month period prior to 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 such period, unless prices are defined by contractual arrangements, excluding escalations based upon 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 recompletion. Reserves on undrilled acreage shall be 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 shall 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, 2011, we had approximately 121 gross proved undeveloped wells (PUDs) all of which we plan to develop within five years at a net estimated cost of approximately $295.1 million. We do not have any aged PUDs (PUDs greater than five years). During 2011, we converted 38 PUDs into proved developed wells (PDPs) at a cost of approximately $111.4 million.

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Our estimated proved reserves and the standardized measure of discounted future net cash flows of the proved reserves at December 31, 2011, 2010, and 2009, the changes in quantities and standardized measure of such 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 2011, Valero Energy Corporation and Sunoco Partners Marketing accounted for 18% and 10%, respectively, of our oil and natural gas revenues. During 2011, our mid-stream segment purchased $71.5 million of our natural gas and NGLs production and provided gathering and transportation services of $4.6 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 2010 and 2009, we eliminated intercompany revenues of $46.8 million and $33.9 million, respectively, attributable to the production of natural gas and NGLs as well as gathering and transportation services.

MID-STREAM

General. Our mid-stream operations are conducted through Superior Pipeline Company L.L.C. Its operations consist of primarily in the buying, selling, gathering, processing and treating of natural gas. In addition, it operates three natural gas treatment plants, 10 operating processing plants, 35 active gathering systems and 934 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,		
	2011	**2010**	**2009**
Gas gathered MMBtu/day	215,805	183,867	183,989
Gas processed MMBtu/day	116,161	82,175	75,908
NGLs sold gallons/day	412,064	271,360	243,492

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

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, 2011, 42% of our mid-stream segment s total volumes and 14% 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

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percentage of that commodity and is directly subject to fluctuations in its market value. For the year ended December 31, 2011, 52% of our mid-stream segment s total volumes and 57% 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, 2011, 6% of our mid-stream segment s total volumes and 29% 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 2011, ONEOK and Gavilon, LLC accounted for approximately 54% and 19%, 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 liquids.

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. The following table shows for each of the periods indicated 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:

Quarter	Oil Price per Bbl High	Oil Price per Bbl Low	NGL Price per Bbl High	NGL Price per Bbl Low	Natural Gas Price per Mcf High	Natural Gas Price per Mcf Low
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
2009:						
Fourth	$ 75.11	$ 71.76	$ 43.22	$ 31.12	$ 4.38	$ 3.35
Third	$ 67.62	$ 60.69	$ 27.38	$ 21.38	$ 3.30	$ 2.37
Second	$ 66.48	$ 39.93	$ 27.30	$ 21.34	$ 2.90	$ 2.59
First	$ 42.26	$ 34.75	$ 19.95	$ 17.89	$ 4.67	$ 2.45

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;

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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; 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. 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 and natural gas prices affect demand. Because oil and natural gas prices are volatile, the level of demand for our services can also be volatile. Both demand for our drilling rigs and dayrates steadily declined throughout 2009. This was followed by a gradual increase in activity (as well as dayrates) during 2010 and 2011.

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 pipelines. Margins received for the delivery of these natural gas and NGLs are dependent on the price for oil, natural gas and natural gas liquids 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.

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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 explorationists, 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 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 systems and deliver the natural gas and NGLs once the gathering 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 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 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.

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EMPLOYEES

As of February 10, 2012, we had approximately 2,244 employees in our contract drilling segment, 214 employees in our oil and natural gas segment, 111 employees in our mid-stream segment and 105 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. We do not know what effect the FERC s other activities will have on the access to markets, the fostering of competition and the cost of doing business.

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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 are other 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

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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 (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 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 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.

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Further, on July 28, 2011, the EPA issued proposed rules that would subject all 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. The EPA proposed rules also include NSPS standards for completions of hydraulically fractured gas wells. These standards include the reduced emission completion (REC) techniques developed in EPA s Natural Gas STAR program along with the pit flaring of gas not sent to the gathering line. The standards would be applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the proposed regulations under NESHAPS include maximum achievable control technology (MACT) standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. We are currently evaluating the effect these proposed rules could have on our business. 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.

We do not know and cannot predict whether any of the proposed legislation or regulations will be adopted as initially written, if at all, or how legislation or new regulations that may be adopted to address GHG emissions and/or hydraulic fracturing would impact our business segments. Depending on the final provisions of such legislation, rules or ordinances, 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.

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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, estim 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 amount of wells we plan to drill or rework;
- prices for oil, NGLs and natural gas;
- demand for oil 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;
- 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;

- expansion and growth of our business and operations;
- demand for our drilling rigs and drilling rig rates;
- 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 or natural gas production to established pipeline systems; and
- federal and state legislative and regulatory initiatives relating to hydrocarbon fracturing 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;

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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 2012 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.

Drilling Customer Demand. With the exception of the drilling we do for our own account, the demand for our 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. 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 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.

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Based on our 2011 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 $356,000 per month ($4.3 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 $196,000 per month ($2.4 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 $175,000 per month ($2.1 million annualized) change in our pre-tax operating cash flow. During 2011, 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 58%, 18% and 66% of our 2011 average daily production for oil, NGLs and natural gas, respectively.

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. 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. Starting December 31, 2009, companies like us that use full cost accounting moved from using the commodity prices existing on the last day of the period to that of 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

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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 periodically review 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%. As of December 31, 2011, 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, even if prices are depressed for only a short period of time. Before 2009, the price was based on the single-day period-end price. The revision to the 12-month average price was made to reduce the affect of short-term volatility and seasonality that previously occurred with single-day pricing. Using the 12-month average may or may not result in write-downs that would have been required had the single-day period-end price been used. 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 or unusually volatile. 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, we recorded a non-cash ceiling test write down of $281.2 million pre-tax ($175.1 million, net of tax) during the quarter ended March 31, 2009. No ceiling test write down was necessary during 2010 or 2011.

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 working capital expenditures because of the growth in our operations. Historically, we have funded our working capital needs through a combination of internally generated cash flow and borrowings under our bank credit agreement. In 2011 we issued $250.0 million of senior subordinated notes (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, 2011, our outstanding long-term debt under our credit agreement was $50.0 million and the amount of the Notes was $250.0 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;

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- place us at a competitive disadvantage to those of our competitors that are less indebted 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 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.

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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 natural gas market is also unsettled due to a number of factors. At times in the past, production from natural gas wells in some geographic areas of the United States was curtailed for considerable periods of time due to a lack of market demand. When demand for natural gas increased the number of wells being shut-in for lack of demand was reduced. It is possible, however, that some of our wells may in the future be shut-in or that natural gas will be sold on terms less favorable than might otherwise be obtained should demand for gas remain depressed. Competition for available markets has been vigorous and there remains great uncertainty about prices that purchasers will pay. Natural gas surpluses could result in our inability to market natural gas profitably, causing us to curtail production and/or receive lower prices for our 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.

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 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;

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- 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 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 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.

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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 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 working capital needs in the growth of our operations. We have $250.0 million of indebtedness outstanding on the Notes, and in addition, have the right to borrow up to $250.0 million under our credit agreement. As of February 10, 2012, we have outstanding borrowings of $50.0 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.

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 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.

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 cancelled 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;

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- 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 drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced explorationists, 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 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 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 periodically review 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, even if prices were depressed for only a short period of time. Prior to 2009, the price was based on the single-day period-end price. The revision to the 12-month average price was made to reduce the affect of short-term volatility and seasonality that previously occurred with single-day pricing. Using the 12-month average may or may not result in write-downs that would have been required had the single-day period-end price been used. 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 or unusually volatile. 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.

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 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 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

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available capacity on these 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 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 2011, our largest customer, QEP Resources, Inc. accounted for approximately 22% of our 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 NGL 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 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.

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. The Act requires the Commodities Futures and Trading Commission (the CFTC) to promulgate rules to define these terms, but we do not know the definitions that the CFTC will actually promulgate or how these definitions will apply to us.

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 Bakken of North Dakota and Montana. 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.

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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, with initial results expected to be available by late 2012 and final results by 2014. In addition, the U.S. Department of Energy is conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods. Also, the U.S. Department of the Interior is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands.

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, on July 28, 2011, the EPA issued proposed rules that would subject all 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. The EPA proposed rules also include NSPS standards for completions of hydraulically fractured gas wells. These standards include the reduced emission completion (REC) techniques developed in EPA s Natural Gas STAR program along with the pit flaring of gas not sent to the gathering line. The standards would be applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the proposed regulations under NESHAPS include maximum achievable control technology (MACT) standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. We are currently evaluating the effect these proposed rules could have on our business.

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 natural gas.

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

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 company s exploration segment distributes royalty. The Plaintiffs central allegation is that the company s exploration segment has underpaid royalty obligations by deducting post-production costs or marketing related fees. Plaintiffs also seek to pursue the case as a class action on behalf of persons who receive royalty from us for our Oklahoma production. We have asserted

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several defenses including that the deductions are permitted under Oklahoma law. We have 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. We have appealed the trial court s order. It is not currently known when the appeal will be acted on by the Oklahoma Appellate courts. Adjudication of the merits of the Plaintiffs claims is stayed until the appeal of the class certification order is decided.

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:

	2011		2010	
Quarter	**High**	**Low**	**High**	**Low**
First	$ 62.47	$ 44.84	$ 51.00	$ 41.32
Second	$ 63.76	$ 51.58	$ 49.82	$ 36.37
Third	$ 62.66	$ 36.50	$ 42.76	$ 33.37
Fourth	$ 53.35	$ 33.58	$ 46.95	$ 35.37

On February 10, 2012, the closing sale price of our common stock, as reported by the NYSE, was $47.03 per share. On that date, there were approximately 1,095 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.

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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.

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 Helmrich & 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 2011, 2010 and 2009 activity.

	As of and for the Year Ended December 31,				
	2011	2010	2009	2008	2007
	(In thousands except per share amounts)				
Revenues	$ 1,208,371	$ 881,845	$ 709,898	$ 1,358,093	$ 1,158,754
Net income (loss)	$ 195,867	$ 146,484	$ (55,500)(1)	$ 143,625(2)	$ 266,258
Net income (loss) per common share:					
Basic	$ 4.11	$ 3.10	$ (1.18)	$ 3.08	$ 5.74
Diluted	$ 4.08	$ 3.09	$ (1.18)	$ 3.06	$ 5.71
Total assets	$ 3,256,720	$ 2,669,240	$ 2,228,399	$ 2,581,866	$ 2,199,819
Long-term debt	$ 300,000	$ 163,000	$ 30,000	$ 199,500	$ 120,600
Other long-term liabilities	$ 113,830	$ 92,389	$ 81,126	$ 75,807	$ 59,115
Cash dividends per common share	$ 0	$ 0	$ 0	$ 0	$ 0

(1) 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.

(2) 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.

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 annual 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 natural gas, NGLs and oil production; the demand for oil 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 2012 capital budget for all of our business segments forecasts a 6% increase over our 2011 capital expenditures, excluding acquisitions. Our oil and natural gas segment s capital budget is $457 million, an 11% decrease over 2011, excluding acquisitions. We plan to continue our aggressive drilling program into 2012 with a significant portion of the wells being horizontal. Our drilling segment s capital budget is $120.0 million, a 27% decrease over 2011. Our plans for 2012 include the construction of one new 1,500 horsepower diesel-electric drilling rig, as well as continuing to refurbish and upgrade several of our existing drilling rigs in our fleet in order that those rigs can be used in horizontal drilling operations. Our mid-stream segment s capital budget is $224.0 million, a 182% increase over 2011. The increase is due to anticipated drilling activity by operators in the areas of our existing gathering systems resulting in new well connections as well as many new projects including new plants discussed further in the Executive Summary.

In developing our initial overall operating budget for 2012, we used average oil and natural gas prices of $90.00 per Bbl and $3.50 per Mcf. Our budget is subject to possible adjustments for various reasons including changes in commodity prices and industry conditions. Our 2012 operating budget will be funded using internally generated cash flow and 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 2011 was 65%, compared to 63% and 59% for the third quarter of 2011 and the fourth quarter of 2010, respectively.

Dayrates for the fourth quarter of 2011 averaged $19,330, a slight increase over the third quarter of 2011 and an increase of 17% over the fourth quarter of 2010. These increases were due primarily to increased demand for drilling rigs in the 1,000 to 1,500 horsepower range which are used in horizontal drilling and provide for higher rates.

Direct profit (contract drilling revenue less contract drilling operating expense) for the fourth quarter of 2011 increased 12% over the third quarter of 2011 and 41% over the fourth quarter of 2010. The increases were primarily due to increases in dayrates and utilization over the comparative periods as discussed above.

Operating cost per day for the fourth quarter of 2011 increased 5% over the third quarter of 2011 and increased 28% over the fourth quarter of 2010. The increases over the third quarter were primarily due to increases in rig servicing costs while the increases over the fourth quarter of 2010 are primarily due to increases in direct expenses due to pay increases for rig personnel and to a lesser extent from increases in rig servicing costs. As a result of competition to keep qualified labor, we anticipate compensation for rig personnel in certain regions to increase during the first quarter of 2012.

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 93% of our working drilling rigs are drilling for oil or NGLs. Of those, approximately 98% are drilling horizontal or directional wells.

At the end of 2010, we began constructing five new 1,500 horsepower, diesel-electric drilling rigs. All of these drilling rigs are now working in the Bakken shale in North Dakota under two-year drilling contracts.

During the third quarter of 2011, we were awarded two additional new build rig contracts for 1,500 horsepower, diesel-electric drilling rigs. These new build rigs will initially be working under three year contracts. One was placed into service during the fourth quarter of 2011 and the other will be placed into service during the first quarter of 2012.

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During the fourth quarter of 2011, we entered into an agreement to build a new 1,500 horsepower, diesel-electric drilling rig to be used in North Dakota starting in the second quarter of 2012. This new build rig will initially be working under a three year contract. Subsequent to the 2011 year-end, we sold an idle 600 horsepower mechanical drilling rig to an unaffiliated third party. Upon deployment of the new drilling rigs during the first and second quarters of 2012, this segment will have 128 drilling rigs in its fleet.

Our anticipated 2012 capital expenditures for this segment are $120.0 million, a 27% decrease over 2011.

As of December 31, 2011, we had 62 term drilling contracts with original terms ranging from six months to three years. Forty-six of these contracts are up for renewal in 2012, 16 in the first quarter, 11 in the second quarter, 13 in the third quarter and six in the fourth quarter and 16 are up for renewal in 2013 and later. These contracts include seven of the eight term contracts for the new drilling rigs discussed above. 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

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 in Oklahoma and Lipscomb County, Texas. The purchase price allocation was $8.4 million for proved properties and $3.9 million for acreage. The net proved developed reserves associated with the acquisition are estimated at 6.6 Bcfe (91% natural gas) with production of 1.7 MMcfe per day. The acquisition also included in excess of 12,000 net held acres held by production for future development.

On August 31, 2011, we acquired certain producing oil and gas properties for $30.5 million in cash, subject to closing adjustments, 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 proved reserves associated with the acquisition are approximately 31.2 Bcfe (99% natural gas), 83% of which is proved developed. The acquisition also included approximately 55,000 net acres of which 96% is held by production.

During the fourth quarter of 2011, we leased approximately 60,000 net acres of undeveloped oil and gas leasehold located in south central Kansas for approximately $17.3 million.

Fourth quarter 2011 production from our oil and natural gas segment was 3,255,000 barrels of oil equivalent (Boe), a 4% increase over the third quarter of 2011 and a 21% increase over the fourth quarter of 2010. The increase in production came primarily from oil and NGL rich prospects where we completed and brought new wells online and, to a lesser extent, from production associated with the acquisitions discussed above. Due to low natural gas prices, we curtailed approximately 237 MMcf of our dry natural gas production in the month of December. The curtailed production was brought back on-line in January. Fourth quarter 2011 oil and NGL production was 42% of our total production compared to 34% of our total production over the fourth quarter of 2010. Our production in 2010 was hindered by delays in securing third party fracture stimulation services and delays associated with connecting wells to gathering systems. In addition, our 2010 production was curtailed because of the unexpected shut-in of some of our production from operational issues experienced at a third party facility that processes our Segno field production.

Fourth quarter 2011 oil and natural gas revenues increased 4% over the third quarter of 2011 and increased 23% over the fourth quarter of 2010. These increases were primarily due to increased production and for the increase over the fourth quarter of 2010, also increased oil and NGL prices.

Our oil prices for the fourth quarter of 2011 increased 2% over the third quarter of 2011 while NGL and natural gas prices decreased 4% and 7%, respectively. Our oil and NGL prices increased 19% and 8%, respectively, over the fourth quarter of 2010 while natural gas prices decreased 24%.

Direct profit (oil and natural gas revenues less oil and natural gas operating expense) decreased 3% from the third quarter of 2011 and increased 21% over the fourth quarter of 2010. The decrease over the third quarter 2011 was primarily attributable to decreases in gas production due to curtailment and decreases in gas and NGL prices. The increase over the fourth quarter 2010 was primarily attributable to increased production and from developmental drilling and acquisitions and increases in oil and NGL prices.

Operating cost per Boe produced for the fourth quarter of 2011 increased 21% over the third quarter of 2011 and increased 6% over the fourth quarter of 2010. The costs were lower in the third quarter of 2011 due to a gross production tax refund received for high cost gas tax credits, in addition, increases in the fourth quarter of 2011 were also due to increases in lease operating expenses (LOE) due to increased workover expense and higher saltwater disposal fees. The increase over the fourth quarter 2010 was primarily due to the increases in LOEs and an increase in production taxes. Production taxes increased due to commodity price increases between the periods and increased oil and NGL production.

For 2011, we hedged approximately 58% of our average daily oil production, approximately 66% of our average natural gas production and approximately 18% of our average natural gas liquids production (percentages based on our 2011 production) to help manage our cash flow and capital expenditure requirements.

Currently for 2012 we have hedged approximately 6,100 Bbls per day of oil production and approximately 50,000 Mmbtu per day of natural gas production. The oil production is hedged under swap contracts at an average price of $97.55 per barrel. The natural gas production is hedged under swap contracts at a comparable average NYMEX price of $5.09. The average basis differential for the applicable swaps is ($0.28). We have NGL hedges of 1,966 Bbls per day in the first quarter, 926 Bbls per day in the second quarter, 380 Bbls per day in the third quarter, and 380Bbls per day in the fourth quarter. The NGLs are hedged under swap contracts at an average price of $42.53 per barrel in the first quarter, $41.15 per barrel in the second quarter, $51.28 per barrel in the third quarter, and $50.28 per barrel in the fourth quarter.

Currently for 2013 we have hedged 3,000 Bbls per day of oil production. The oil production is hedged under swap contracts at an average price of $101.91 per barrel.

During 2011, we drilled 160 wells (82.42 net wells). Our 2012 production guidance is approximately 13.2 to 13.5 MMBoe, an increase of 9% to 12% over 2011, although actual results will continue to be subject to the timing of third party services, among other factors. For 2012, we plan to participate in the drilling of 160 wells and the level of our capital expenditures is $457.0 million.

Mid-Stream

Fourth quarter 2011 liquids sold per day increased 14% over the third quarter of 2011 and increased 76% over the fourth quarter of 2010. The increases were primarily the result of upgrades and expansions to existing plants and the connection of new wells. For the fourth quarter of 2011, gas processed per day increased 21% over the third quarter of 2011 and 84% over the fourth quarter of 2010. In 2010 and 2011, we upgraded several of our existing processing facilities and added processing plants which was the primary reason for increased volumes. For the fourth quarter of 2011, gas gathered per day increased 13% over the third quarter of 2011 and increased 37% over the fourth quarter of 2010 primarily from well connects throughout 2011.

NGL prices in the fourth quarter of 2011 decreased 10% from the price received in the third quarter of 2011 and 2% from the price received in the fourth quarter of 2010. The price of NGLs as compared to natural gas affects the revenue in our mid-stream operations and determines the fractionation spread which is the difference in the value received for the NGLs recovered from natural gas in comparison to the amount received for the equivalent MMBtu s of natural gas if unprocessed.

Direct profit (mid-stream revenues less mid-stream operating expense) for the fourth quarter of 2011 increased 4% over the third quarter of 2011 and decreased 22% from the fourth quarter of 2010. The increase resulted primarily from increased liquids sold and gas processed volumes. The decrease over the fourth quarter of 2010 was primarily due to renegotiated contracts with customers at one of our processing plants whereby the contracts changed from POI to POP. Total operating cost for our mid-stream segment for the fourth quarter of 2011 increased 5% over the third quarter of 2011 and increased 87% over the fourth quarter of 2010 due primarily to the increase in gas purchased due to increased volumes.

Our Hemphill County facility in Texas is currently processing approximately 100 MMcf per day, after the addition of our fourth gas processing plant. Due to the continued high level of activity around the Hemphill facility, we will be installing an additional 45 MMcf per day gas processing plant which will increase this facility s processing capacity to approximately 160 MMcf per day. This new plant should be completed during the second quarter of 2012.

At our Cashion facility, we are continuing to connect new wells to the system as well as installing a larger, more efficient gas processing plant. The installation of the new 25 MMcf per day high efficiency turbo-expander processing plant is scheduled to be operational during the second quarter of 2012.

We are also very active in the Mississippian play in north central Oklahoma. We completed construction of a new gathering system and gas processing plant in Grant County, Oklahoma during the fourth quarter of 2011. This system consists of approximately seven miles of gathering pipeline and a gas processing plant. Also in this area, we have begun construction of another gathering system and processing plant in Noble and Kay counties in Oklahoma. This system will initially consist of approximately 10 miles of 12 and 16 pipe with a 10 MMcf per day gas processing plant that will be upgraded to a 30 MMcf per day gas processing plant in the fourth quarter of 2012.

Along with the activities in the mid-continent area, we are continuing to expand operations in the Appalachian region. In the fourth quarter of 2011, we completed construction of a 16 mile, 16 pipeline and accompanying compressor station in Preston County, West Virginia. This system is currently flowing approximately 6 MMcf per day. In addition to the Preston County gathering system, we have begun construction of another gathering facility in Allegheny and Butler counties, Pennsylvania. The first phase of this project consists of approximately seven miles of gathering pipeline and a compressor station. The first well has been connected to this system and is currently flowing approximately 5 MMcf per day into a third party transmission line.

Our anticipated capital expenditures for 2012 are $224.0 million.

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	Oil and natural gas properties Shareholder s equity

	Estimates of rates of forfeitures	Operating expenses General and administrative expenses
Accounting for derivative instruments and hedging	Derivatives measured at fair value	Current and non-current derivative assets and liabilities
	Derivatives measured for effectiveness and ineffectiveness	Other comprehensive income as a component of equity
	Non-qualifying derivatives measured at fair value	Oil and natural gas revenue

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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, 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 96% 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, 2011. Included in Part I, Item 1 of this report are the qualifications of our independent petroleum engineering firm and the company s 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. The average unescalated prices used in our reserve estimates were $96.19 per Bbl for oil, $61.78 per Bbl for NGLs and $4.12 per Mcf for natural gas, adjusted for price differentials.

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 2011 production level of 12.1 million barrels of oil equivalent (MMBoe), a 5% decline in the amount of our 2011 oil, NGLs and natural gas reserves would increase our DD&A rate by $0.84 per Boe and would decrease pre-tax income by $10.2 million annually. A 5% increase in the amount of our 2011 oil, NGLs and natural gas reserves would decrease our DD&A rate by $0.72 per Boe and would increase pre-tax income by $8.7 million annually.

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.

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 a non-cash charge to earnings. If required, it reduces earnings and impacts shareholders equity in the period of occurrence and results in lower depreciation, depletion and amortization 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 oil or natural gas prices, even if temporary, increases the chance of a ceiling test write-down. Based on the 12-month 2011 average unescalated prices of $96.19 per barrel of oil, $61.78 per barrel of NGLs and $4.12 per Mcf of natural gas, adjusted for price differentials, for the estimated life of the respective properties, the unamortized cost of our oil and natural gas properties did not exceeded the ceiling of our proved oil, NGL and natural gas reserves.

Derivative instruments qualifying as cash flow hedges are to be included in the computation of limitation on capitalized costs. Our qualifying cash flow hedges used in the ceiling test determination at December 31, 2011, consisted of swaps covering 5.0 MMBoe in 2012 and 0.7 MMBoe in 2013. The effect of those hedges on the December 31, 2011 ceiling test was a $22.1 million pre-tax increase in the discounted net cash flows of our oil and natural gas properties. Even without the impact of those hedges, we would not have been required to take a write-down for the quarter. Our oil and natural gas hedging activities are discussed in Note 13 of our Notes to Consolidated Financial Statements.

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

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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. No significant impairments were recorded at December 31, 2011, 2010 or 2009.

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 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, 2011, 2010 or 2009.

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 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 and in 2009, one under footage and none under turnkey.

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 account for 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 for the next 24 months. This statement 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. Derivatives that do not qualify for hedge treatment must be recorded at fair value with gains (losses) recognized in earnings in the period of change.

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New Accounting Standards

Improving Disclosures about Fair Value Measurements. In January 2010, the FASB issued ASU 2010-06 *Fair Value Measurements and Disclosures (ASC 820): Improving Disclosures about Fair Value Measurements,* which provides additional guidance to improve disclosures regarding fair value measurements. The ASU amends ASC 820-10, *Fair Value Measurements and Disclosures Overall* (formerly FAS 157, Fair Value Measurements) to add two new disclosures: (1) transfers in and out of Level 1 and 2 measurements and the reasons for the transfers, and (2) a gross presentation of activity within the Level 3 roll forward. The ASU also includes clarifications to existing disclosure requirements on the level of disaggregation and disclosures regarding inputs and valuation techniques. The ASU applies to all entities required to make disclosures about recurring and nonrecurring fair value measurements. The effective date of the ASU was the first interim or annual reporting period beginning after December 15, 2009 and was adopted January 1, 2010, except for the gross presentation of the Level 3 roll forward information, which was adopted January 1, 2011. Because it only includes enhanced disclosures, this statement did not have a significant impact on us.

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.

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 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.

Testing Goodwill for Impairment. In August 2011, the FASB issued ASU 2011-08 *Intangibles-Goodwill and Other (ASC 350): Testing Goodwill for Impairment.* This ASU is intended to simplify how entities, both public and nonpublic, test goodwill for impairment. ASU 2011-08 permits an entity to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test described in ASC 350, *Intangibles-Goodwill and Other.* The more-likely-than-not threshold is defined as having a likelihood of more than 50%.

ASU 2011-08 is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011.

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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 natural gas, oil and NGLs we produce;
- the prices we receive for our oil, natural gas and NGL 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:

	2011	2010	2009
	(In thousands except percentages)		
Working capital	$ 15,715	$ 41,052	$ 22,948
Long-term debt	$ 300,000	$ 163,000	$ 30,000
Shareholders equity	$ 1,947,017	$ 1,710,617	$ 1,565,810(1)
Ratio of long-term debt to total capitalization	13%	9%	2%(1)
Net income (loss)	$ 195,867	$ 146,484	$ (55,500)(1)
Net cash provided by operating activities	$ 608,455	$ 390,072	$ 490,475
Net cash used in investing activities	$ (768,236)	$ (536,261)	$ (271,927)
Net cash provided by (used in) financing activities	$ 159,257	$ 146,408	$ (217,992)

(1) 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. The write down impacted our 2009 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:

	2011	2010	2009
Contract Drilling:			
Average number of our drilling rigs in use during the period	76.1	61.4	38.9
Total number of drilling rigs owned at the end of the period	127	121	130
Average dayrate	$ 18,842	$ 15,478	$ 16,713
Oil and Natural Gas:			
Oil production (MBbls)	2,511	1,521	1,286
Natural gas liquids production (MBbls)	2,239	1,549	1,488
Natural gas production (MMcf)	44,104	40,756	44,063
Average oil price per barrel received	$ 87.18	$ 69.52	$ 56.33
Average oil price per barrel received excluding hedges	$ 93.49	$ 76.65	$ 56.64
Average NGL price per barrel received	$ 43.64	$ 37.04	$ 22.81
Average NGL price per barrel received excluding hedges	$ 44.44	$ 36.96	$ 25.66

Average natural gas price per mcf received	$ 4.26	$ 5.62	$ 5.59
Average natural gas price per mcf received excluding hedges	$ 3.78	$ 4.05	$ 3.26
Mid-Stream:			
Gas gathered MMBtu/day	215,805	183,867	183,989
Gas processed MMBtu/day	116,161	82,175	75,908
Gas liquids sold gallons/day	412,064	271,360	243,492
Number of natural gas gathering systems	35	34	33
Number of processing plants	10	10	8

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At December 31, 2011, we had unrestricted cash totaling $0.8 million and had borrowed $50.0 million of the $250.0 million we had elected to 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 Notes) due 2021. The 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 approximately $220.3 million outstanding as of May 18, 2011. The remaining proceeds were used for general working capital purposes.

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 working capital of $15.7 million, $41.1 million and $22.9 million as of December 31, 2011, 2010 and 2009, respectively. The effect of our derivatives increased working capital by $18.0 million, $5.4 million and $4.7 million as of December 31, 2011, 2010 and 2009, respectively.

Contract Drilling

Many factors influence the number of drilling rigs we are working at any one 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.

As activity has increased over last year s levels, competition to keep qualified labor has also increased. 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 of 2011 for drilling personnel in all our divisions. As a result of competition to keep qualified labor, we anticipate compensation for rig personnel in certain regions to increase during the first quarter of 2012.

Over the past year, as more of our customers shift to drilling horizontal wells, demand for drilling rigs in the 1,000 to 1,500 horsepower range has increased as those drilling rigs have the horsepower ideally suited for horizontal drilling. The future demand for and the availability of drilling rigs to meet that demand will have an impact on our future dayrates. For 2011, our average dayrate was $18,842 per day compared to $15,478 per day for 2010. Our average number of drilling rigs used in 2011 was 76.1 drilling rigs (61%) compared with 61.4 drilling rigs (50%) in 2010. Based on the average utilization of our drilling rigs during 2011, a $100 per day change in dayrates has a $7,610 per day ($2.8 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 $52.2 million, $40.1 million and $15.0 million for 2011, 2010 and 2009, respectively from our contract drilling segment and eliminated the associated operating expense of $32.6 million, $31.0 million and $13.7 million during 2011, 2010 and 2009, respectively, yielding $19.6 million, $9.1 million and $1.3 million during 2011, 2010 and 2009, 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 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 2011, 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 $356,000 per month ($4.3 million annualized) change in our pre-tax operating cash flow. Our 2011 average natural gas price was $4.26 compared to an average natural gas price of $5.62 for 2010 and $5.59 for 2009. A $1.00 per barrel change in our oil price, without the effect of hedging, would have a $196,000 per month ($2.4 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGL prices, without the effect of hedging, would have a $175,000 per month ($2.1 million annualized) change in our pre-tax operating cash flow based on our production in 2011. Our 2011 average oil price per barrel was $87.18 compared with an average oil price of $69.52 in 2010 and $56.33 in 2009 and our 2011 average NGL price per barrel was $43.64 compared with an average liquids price of $37.04 in 2010 and $22.81 in 2009.

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.

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 in nine month increments.

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, 10 processing plants, 35 gathering systems and 934 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 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 2011, 2010 and 2009 this segment purchased $71.5 million, $42.4 million and $29.3 million, respectively, of our natural gas production and natural gas liquids and provided gathering and transportation services of $4.6 million, $4.4 million and $4.6 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 215,805 MMBtu per day in 2011 compared to 183,867 MMBtu per day in 2010 and 183,989 MMBtu per day in 2009, processed an average of 116,161 MMBtu per day in 2011 compared to 82,175 MMBtu per day in 2010 and 75,908 MMBtu per day in 2009 and sold NGLs of 412,064 gallons per day in 2011 compared to 271,360 gallons per day in 2010 and 243,492 gallons per day in 2009. Volumes processed increased primarily due to the addition of wells connected and recent upgrades to several of our processing systems. Gas gathering volumes per day in 2011 increased 17% compared to 2010 primarily from wells connected to our systems throughout 2011. Processed volumes increased 41% over the comparative years and NGLs sold increased 52% over the comparative years primarily due to the addition of wells connected, recent upgrades to several of our processing systems and the doubling in size of our Hemphill facility in the Texas Panhandle.

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Our Credit Agreement and Senior Subordinated Notes

Credit Agreement. On September 13, 2011, we entered into a Senior Credit Agreement (credit agreement) that replaced our previous credit agreement which was scheduled to mature on May 24, 2012. The credit agreement has a maturity date of September 13, 2016. The amount available to be borrowed is the lesser of the amount we elect as the commitment amount (currently $250.0 million) or the value of the borrowing base as determined by the lenders (currently $600.0 million), but in either event, not to exceed the maximum credit agreement amount of $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. To date, in connection with this new credit agreement, we paid $1.8 million in origination, agency, syndication and other related fees. We are amortizing these fees over the life of the credit agreement. At both December 31, 2011 and February 10, 2012, borrowings were $50.0 million.

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

Lender	Participation Interest
BOK (BOKF, NA, dba Bank of Oklahoma)	20.00%
BBVA Compass Bank	20.00%
BMO	16.80%
Bank of America, N.A.	16.80%
Comerica Bank	8.80%
Crédit Agricole	8.80%
BNP Paribas	8.80%
	100.00%

The amount of the borrowing base, which is subject to redetermination 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 amount 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%, and is payable at the end of each month and the principal borrowed may be paid at any time, in part or in whole, without a premium or penalty. At December 31, 2011, all of our $50.0 million in outstanding borrowings were subject to LIBOR.

We used borrowings under the credit agreement to pay off the commitments issued under our previous credit agreement. In addition, 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 of the Borrowers.

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.

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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, 2011, 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 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. We also terminated two $15.0 million interest rate swaps associated with that debt with a settlement cost to us of $1.5 million.

The Notes are guaranteed by our wholly-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 were issued under an Indenture dated as of May 18, 2011, between us and Wilmington Trust FSB, as Trustee (the Trustee), as supplemented by the First Supplemental Indenture dated as of May 18, 2011, between us, the Guarantors and the Trustee, establishing the terms and providing for the issuance of the Notes (the Supplemental Indenture). The discussion of the Notes in this annual report is qualified by and subject to the actual terms of the Indenture and the First Supplemental Indenture.

The Notes bear interest at a rate of 6.625% per year (payable semi-annually in arrears on May 15 and November 15 of each year), and will mature on May 15, 2021.

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 and the Supplemental Indenture contain customary events of default. The Indenture governing the Notes 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, 2011.

Capital Requirements

Drilling Dispositions, Acquisitions and Capital Expenditures. During 2009, we sold three mechanical drilling rigs (ranging in horsepower from 750 to 1,000) for $8.6 million and recorded a $4.8 million gain. In the third quarter 2009, we recognized an early termination fee associated with the cancellation of long-term contracts by a customer on two of eight rigs we postponed construction on in 2008. In addition, as a result of an existing contractual obligation, we took delivery of a new 1,500 horsepower drilling rig during the fourth quarter of 2009 at a cost of $13.2 million. The customer, who had signed a two year term contract for this rig when it was ordered, opted not to take delivery of the rig and paid an early termination fee under the contract provisions during the fourth quarter of 2009.

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 working in the Bakken shale in North Dakota under two-year drilling contracts.

During the third quarter of 2011, we were awarded two additional new build rig contracts for 1,500 horsepower, diesel-electric drilling rigs. These new build rigs will initially be working under three year contracts. One was placed into service during the fourth quarter of 2011 and the other will be placed into service during the first quarter of 2012.

During the fourth quarter of 2011, we entered into an agreement to build a new 1,500 horsepower, diesel-electric drilling rig to be used in North Dakota starting in the second quarter of 2012. This new build rig will initially be working under a three year contract. Subsequent to the 2011 year-end, we sold an idle 600 horsepower mechanical drilling rig to an unaffiliated third party. Upon deployment of the new drilling rigs during the first and second quarters of 2012, this segment will have 128 drilling rigs in its fleet.

Our anticipated 2012 capital expenditures for this segment are $120.0 million. At December 31, 2011, we had commitments to purchase approximately $6.6 million for drill pipe, top drives and related equipment over the next twelve months. We have spent $162.2 million for capital expenditures during 2011 compared to $118.8 million in 2010 and $67.7 million in 2009.

Oil and Natural Gas Acquisitions and Capital Expenditures. Most of our capital expenditures for this segment are discretionary and directed toward future growth. Our 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 provide us with a large degree of flexibility in deciding when and if to incur these costs. We completed drilling 160 gross wells (82.42 net wells) in 2011 compared to 167 gross wells (87.52 net wells) in 2010 and 95 gross wells (42.51 net wells) in 2009. Our 2011 total capital expenditures for our oil and natural gas segment, excluding a $23.3 million ARO liability, and $50.0 million for acquisitions, totaled $506.7 million compared to 2010 capital expenditures of $361.4 million (excluding a $9.9 million ARO liability and $92.6 million for acquisitions) and 2009 capital expenditures of $226.0 million (excluding a $4.6 million

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ARO liability). Currently we plan to participate in drilling approximately 160 gross wells in 2012 and estimate our total capital expenditures (excluding any possible acquisitions) for our oil and natural gas segment will be approximately $457.0 million. Whether we are able to drill the full number of wells we are planning on drilling 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 and natural gas, the cost to drill wells, the weather and the efforts of outside industry partners.

During 2008 and 2009, we acquired interests in approximately 60,000 net undeveloped acres in the Marcellus Shale Play, located mainly in Pennsylvania and Maryland for approximately $43.6 million. In July 2009, we received $7.1 million and approximately 1,500 net undeveloped acres, representing payment for our 50% interest in 4,000 gross undeveloped acres and reimbursement for costs we paid on their behalf. On September 30, 2009, per our agreement with certain unaffiliated third parties, we were paid approximately $14.9 million for our 50% interest in approximately 18,000 gross undeveloped acres of the Marcellus Shale and $26.1 million for a receivable from the third parties for their 50% share of the costs we paid on their behalf to acquire the acreage. The sales proceeds reduced undeveloped leasehold and no gain or loss was recorded on this sale. We now have an interest in approximately 50,500 net undeveloped acres.

In June 2010, we completed an acquisition of oil and natural gas properties from certain unaffiliated parties. The properties were purchased for approximately $73.7 million in cash, after post closing adjustments. After these adjustments, 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. At the time of acquisition, proved developed producing net reserves associated with the 10 acquired producing wells was approximately 762,000 BOE consisting of 511,000 barrels of oil, 155,000 barrels of NGLs and 573 MMcf of natural gas.

Also during the second quarter of 2010, we completed an acquisition consisting of approximately 32,000 net acres of undeveloped oil and gas leasehold located in Southwest Oklahoma and North Texas for approximately $17.6 million from an unaffiliated party.

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 in Oklahoma and Lipscomb County, Texas. The purchase price allocation was $8.4 million for proved properties and $3.9 million for acreage. The net proved developed reserves associated with the acquisition are estimated at 6.6 Bcfe (91% natural gas) with production of 1.7 MMcfe per day. 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, subject to closing adjustments, 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 proved reserves associated with the acquisition are approximately 31.2 Bcfe (99% natural gas), 83% of which is proved developed. The acquisition also included approximately 55,000 net acres of which 96% is held by production.

During the fourth quarter of 2011, we leased approximately 60,000 net acres of undeveloped oil and gas leasehold located in south central Kansas for approximately $17.3 million.

Mid-Stream Acquisitions and Capital Expenditures. Our Hemphill County facility in Texas is currently processing approximately 100 MMcf per day, after the addition of our fourth gas processing plant, completed in the fourth quarter of 2010. Due to the continued high level of activity around the Hemphill facility, we will be installing an additional 45 MMcf per day gas processing plant which will increase this facility s processing capacity to approximately 160 MMcf per day. This new plant should be completed during the second quarter of 2012.

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At our Cashion facility, we are continuing to connect new wells to the system as well as installing a larger, more efficient gas processing plant. The installation of the new 25 MMcf per day high efficiency turbo-expander processing plant is scheduled to be operational during the second quarter of 2012.

We are also very active in the Mississippian play in north central Oklahoma. We completed construction of a new gathering system and gas processing plant in Grant County, Oklahoma during the fourth quarter of 2011. This system consists of approximately seven miles of gathering pipeline and a gas processing plant. Also in this area, we have begun construction of another gathering system and processing plant in Noble and Kay counties in Oklahoma. This system will initially consist of approximately 10 miles of 12 and 16 pipe with a 10 MMcf per day gas processing plant that will be upgraded to a 30 MMcf per day gas processing plant in the fourth quarter of 2012.

Along with the activities in the mid-continent area, we are continuing to expand operations in the Appalachian region. In the fourth quarter of 2011, we completed construction of a 16 mile, 16 pipeline and accompanying compressor station in Preston County, West Virginia. This system is currently flowing approximately 6 MMcf per day. In addition to the Preston County gathering system, we have begun construction of another gathering facility in Allegheny and Butler counties, Pennsylvania. The first phase of this project consists of approximately seven miles of gathering pipeline and a compressor station. The first well has been connected to this system and is currently flowing approximately 5 MMcf per day into a third party transmission line.

During 2011, our mid-stream segment incurred $79.4 million in capital expenditures as compared to $29.8 million in 2010 and $9.9 million in 2009, including acquisitions. For 2012, we have budgeted capital expenditures of approximately $224.0 million.

Contractual Commitments

At December 31, 2011, 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]	$ 461,570	$ 17,920	$ 35,839	$ 85,435	$ 322,376
Operating leases [2]	12,745	6,219	6,357	169	0
Drill pipe, drilling components and equipment purchases [3]	6,933	6,933	0	0	0
Total contractual obligations	$ 481,248	$ 31,072	$ 42,196	$ 85,604	$ 322,376

(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, 2011 interest rates of 6.625% for the Notes and 2.7% for the credit agreement.

(2) We lease office space or yards in Elmwood, Elk City, Oklahoma City, Quinton and Tulsa, Oklahoma; Canadian and Houston, Texas; Denver and Englewood, Colorado; Pinedale, Wyoming; and Pittsburgh, Pennsylvania under the terms of operating leases expiring through September, 2015. 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 purchase approximately $6.6 million of new drilling rig components, drill pipe, drill collars and related equipment and $0.3 million remaining towards a gas treating plant over the next twelve months.

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At December 31, 2011, we also had the following commitments and contingencies that could create, increase or accelerate our liabilities:

Other Commitments	Total Accrued	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
		Estimated Amount of Commitment Expiration Per Period (In thousands)			
Deferred compensation plan [1]	$ 2,463	Unknown	Unknown	Unknown	Unknown
Separation benefit plans [2]	$ 6,845	$ 806	Unknown	Unknown	Unknown
Derivative liabilities commodity hedges	$ 2,657	$ 2,657	$ 0	$ 0	$ 0
ARO liability [3]	$ 96,446	$ 3,040	$ 20,064	$ 4,517	$ 68,825
Gas balancing liability [4]	$ 3,263	Unknown	Unknown	Unknown	Unknown
Repurchase obligations [5]	$ 0	Unknown	Unknown	Unknown	Unknown
Workers compensation liability [6]	$ 17,026	$ 8,367	$ 3,006	$ 1,257	$ 4,396

(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 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 $22,000 in 2011,

$22,000 in 2010 and $1,000 in 2009.

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

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Derivative Activities

Periodically we enter into hedge transactions covering part of the interest rate payable under our credit agreement as well as the prices to be received for a portion of our oil, NGLs and natural gas production.

Interest Rate Swaps. From time to time we enter into interest rate swaps to manage our exposure to possible future interest rate increases under our credit agreement. Under these transactions we swap the variable interest rate we would otherwise incur on a portion of our bank debt for a fixed rate of interest. In May 2011, in association with the repayment of outstanding borrowings under our credit agreement, we terminated our two outstanding interest rate swaps that were previously accounted for as cash flow hedges, resulting in an increase of approximately $1.5 million in interest expense. Approximately $1.1 million of that expense was capitalized and is being amortized over the life of the assets.

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. Based on our 2011 average daily production, the approximated percentages of our production that we have hedged are as follows:

Oil and Natural Gas Segment:

	Q1 12	Q2 12	Q3 12	Q4 12	2013
Daily oil production	81%	91%	91%	91%	44%
Daily natural gas production	37%	37%	54%	37%	0%
Natural gas liquids production	32%	15%	6%	6%	0%

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 the counterparties will not be able to meet their financial obligations under the transactions. Based on our evaluation at December 31, 2011, we determined that there was no material risk of non-performance by our counterparties. At December 31, 2011, 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, 2011 (In millions)
Bank of Montreal	$ 18.7
Bank of America, N.A.	6.5
BNP Paribas	6.1
Comerica Bank	1.4
BBVA Compass Bank	1.0
BP Corporation	0.2
Crédit Agricole Corporate and Investment Bank, London Branch	0.1
Macquarie Bank	(0.2)
Total assets (liabilities)	$ 33.8

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, 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. At December 31 2010, we recorded

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the fair value of our commodity derivatives on our balance sheet as current and non-current derivative assets of $5.6 million and $2.5 million, respectively, and current and non-current derivative liabilities of $13.3 million and $3.9 million, respectively.

We recognize in accumulated OCI the effective portion of any changes in fair value 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, 2011, we had a gain of $19.0 million, net of tax from our oil and natural gas segment derivatives in accumulated OCI.

Based on market prices at December 31, 2011, we expect to transfer to earnings a gain of approximately $18.0 million, net of tax, of the loss included in accumulated OCI during the next 12 months in the related month of production. The commodity derivative instruments existing as of December 31, 2011 are expected to mature by December 2013.

Certain derivatives do not qualify for designation as cash flow hedges. We had three basis swaps that did not qualify as cash flow hedges that expired in December 2011. For these derivatives, any changes in their fair value occurring before their maturity (i.e., temporary fluctuations in value) are reported in oil and natural gas revenues in our consolidated statements of operations. 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. Any change in fair value resulting from ineffectiveness is recognized in our oil and natural gas revenues. The effect of these realized and unrealized gains and losses on our revenues and expenses were as follows at December 31:

	2011	2010 (In thousands)	2009
Oil and natural gas revenue:			
Realized gains on oil and natural gas derivatives	$ 3,988	$ 53,473	$ 97,864
Unrealized gains (losses) on ineffectiveness of cash flow hedges	2,749	700	(897)
Unrealized gains (losses) on non-qualifying oil and natural gas derivatives	(336)	336	(1,047)
Impact on pre-tax earnings	$ 6,401	$ 54,509	$ 95,920

Stock and Incentive Compensation

During 2011, we granted awards covering 211,050 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 $10.8 million. Compensation expense will be recognized over their two and three year vesting periods, and during 2011, we recognized $4.1 million in additional compensation expense and capitalized $1.0 million for these awards. 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. During 2009, we did not grant any awards of restricted stock. No SAR awards were made during 2011, 2010, or 2009.

During 2011, we recognized compensation expense of $10.0 million for all of our restricted stock, stock options and SAR grants and capitalized $2.5 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 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.

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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 2011, 2010 and 2009, the total we received for all of these fees was $1.4 million, $1.5 million and $1.1 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.

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

2011 versus 2010

Following is a comparison of selected operating and financial data:

	2011	2010	Percent Change (1)
Total revenue	$ 1,208,371,000	$ 881,845,000	37%
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%	0%
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	$ 516,316,000	$ 400,807,000	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%
NGL 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%
Interest expense, net	$ 4,167,000	$ 0	NM
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.

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 NGL 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 $115.5 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 NGL prices partially offset by decreases in prices for natural gas. Average oil and NGL 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%, NGL 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 due to increased well servicing costs and higher saltwater disposal fees and higher gross production taxes due to higher oil prices and revenue from 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.

Depreciation, depletion and amortization (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 NGL 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, upgrades to several of our processing facilities and the doubling in size of our Hemphill facility in the Texas Panhandle. 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.

Other

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

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 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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2010 versus 2009

Following is a comparison of selected operating and financial data:

	2010	2009	Percent Change [1]
Total revenue	$ 881,845,000	$ 709,898,000	24%
Net income (loss)	$ 146,484,000	$ (55,500,000)	NM
Contract Drilling:			
Revenue	$ 316,384,000	$ 236,315,000	34%
Operating costs excluding depreciation	$ 186,813,000	$ 140,080,000	33%
Percentage of revenue from daywork contracts	100%	100%	0%
Average number of drilling rigs in use	61.4	38.9	58%
Average dayrate on daywork contracts	$ 15,478	$ 16,713	(7)%
Depreciation	$ 69,970,000	$ 45,326,000	54%
Oil and Natural Gas:			
Revenue	$ 400,807,000	$ 357,879,000	12%
Operating costs excluding depreciation, depletion, amortization and impairment	$ 105,365,000	$ 87,734,000	20%
Average oil price (Bbl)	$ 69.52	$ 56.33	23%
Average NGL price (Bbl)	$ 37.04	$ 22.81	62%
Average natural gas price (Mcf)	$ 5.62	$ 5.59	1%
Oil production (Bbl)	1,521,000	1,286,000	18%
NGL production (Bbl)	1,549,000	1,488,000	4%
Natural gas production (Mcf)	40,756,000	44,063,000	(8)%
Depreciation, depletion and amortization rate (Boe)	$ 11.94	$ 11.22	6%
Depreciation, depletion and amortization	$ 118,793,000	$ 114,681,000	4%
Impairment of oil and natural gas properties	$ 0	$ 281,241,000	NM
Mid-Stream Operations:			
Revenue	$ 154,516,000	$ 108,628,000	42%
Operating costs excluding depreciation and amortization	$ 122,146,000	$ 87,908,000	39%
Depreciation and amortization	$ 15,385,000	$ 16,104,000	(4)%
Gas gathered MMBtu/day	183,867	183,989	0%
Gas processed MMBtu/day	82,175	75,908	8%
Gas liquids sold gallons/day	271,360	243,492	11%
General and administrative expense	$ 26,152,000	$ 24,011,000	9%
Interest expense, net	$ 0	$ 539,000	NM
Income tax expense (benefit)	$ 90,737,000	$ (32,226,000)	NM
Average interest rate	3.5%	4.0%	(13)%
Average long-term debt outstanding	$ 94,873,000	$ 111,808,000	(15)%

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

Contract Drilling:

Drilling revenues increased $80.1 million or 34% in 2010 versus 2009 primarily due to a 58% increase in the average number of rigs in use during 2010 compared to 2009 and increased mobilization revenue offset by a 7% lower average dayrate. Average drilling rig utilization increased from 38.9 drilling rigs in 2009 to 61.4 drilling rigs in 2010 as commodity prices improved in 2010 compared to 2009, creating increased demand for drilling rigs.

Drilling operating costs increased $46.7 million or 33% between the comparative years of 2010 and 2009 primarily due to increases in the number of drilling rigs used and increases in general and administrative expenses somewhat offset by decreases in worker s compensation. During 2009, competition to keep and attract qualified employees to meet our requirements did not materially affect us due to the depressed conditions within our industry. Due to an increase in activity over 2009 levels, competition to keep qualified labor has increased in 2010. In the third quarter 2010, we increased compensation for drilling personnel in Oklahoma, Texas and Louisiana. Contract drilling depreciation increased $24.6 million or 54% primarily due to an increase in the number of drilling rigs being utilized and an increase in capital expenditures for upgrades to existing drilling rigs in our fleet.

Oil and Natural Gas

Oil and natural gas revenues increased $42.9 million or 12% in 2010 as compared to 2009 primarily due to an increase in average oil, NGL and natural gas prices partially offset by a 3% decrease in equivalent production volumes. Average oil prices between the comparative years increased 23% to $69.52 per barrel, NGL prices increased 62% to $37.04 per barrel and natural gas prices increased 1% to $5.62 per Mcf. In 2010, as compared to 2009, oil production increased 18%, NGL production increased by 4% and natural gas production decreased 8%. 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 while production growth was hampered primarily during the first nine months of the year by the lack of availability of fracing services to complete wells.

Oil and natural gas operating costs increased $17.6 million or 20% between the comparative years of 2010 and 2009 due primarily to higher gross production taxes due to increased oil and natural gas sales revenue between the periods. Production taxes in 2009 were also reduced by $5.8 million for production tax credits attributable to high-cost gas wells.

DD&A increased $4.1 million or 4% primarily due to a 6% increase in our DD&A rate slightly offset by a 3% decrease in equivalent production. The 2009 DD&A rate was lower after a $281.2 million pre-tax non-cash ceiling test write-down of the carrying value of our oil and natural gas properties at the end of the first quarter in 2009 as a result of a decline in commodity prices and the DD&A rate increases throughout 2010 from increased net book value on new reserves added. 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 $45.9 million or 42% for 2010 as compared to 2009 primarily due to higher NGL and natural gas prices and higher NGL volumes processed and sold. The average price for NGLs sold increased 31% and the average price for natural gas sold increased 28%. Gas processing volumes per day increased 8% between the comparative periods and NGLs sold per day increased 11% 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 throughout 2010. NGLs sold volumes per day increased due to both an increase in volumes processed and upgrades to several of our processing facilities. Gas gathering volumes per day remained flat.

Operating costs increased $34.2 million or 39% in 2010 compared to 2009 primarily due to a 36% increase in prices paid for natural gas purchased and a 9% increase in purchased volumes. Depreciation and amortization decreased $0.7 million, or 4%, primarily due to decreased amortization on our intangible assets.

Other

Other revenue of $10.1 million for 2010 was primarily attributable to the sale of eight mechanical drilling rigs and the sale of a gas pipeline in which we owned a 60% interest, partially offset by a $2.5 million loss associated with the write-off of progress payments made on a gas plant contract that was terminated.

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General and administrative expenses increased $2.1 million or 9% compared to 2009 primarily due to increases in employee costs.

Interest expense, net of capitalized interest, decreased $0.5 million between the comparative years. 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 decreased by 13% and our average debt outstanding was 15% lower in 2010 as compared to 2009. Total interest expense was increased $1.2 million for 2010 and $1.0 million for 2009 from interest rate swap settlements.

Income tax expense (benefit) changed from a benefit of $32.2 million in 2009 to an expense of $90.7 million in 2010 due to the non-cash ceiling test write-down of $281.2 million pre-tax ($175.1 million, net of tax) of our oil and natural gas properties during the quarter ended March 31, 2009, which was more than offset by improved performance of our operating segments. Our effective tax rate was 38.3% and 36.7% for 2010 and 2009, respectively. The portion of our taxes reflected as a current income tax benefit for 2010 was $9.9 million as compared to a benefit of $0.2 million in 2009. Income taxes paid in 2010 were $3.1 million.

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 2011 production, a $0.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $356,000 per month ($4.3 million annualized) change in our pre-tax cash flow. A $1.00 per barrel change in our oil price would have a $196,000 per month ($2.4 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGLs prices would have a $175,000 per month ($2.1 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.

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Oil and Natural Gas Segment:

At December 31, 2011, the following cash flow hedges were outstanding:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Jan 12 Dec 12	Crude oil swap	5,250 Bbl/day	$96.54	WTI NYMEX
Jan 13 Dec 13	Crude oil swap	2,000 Bbl/day	$102.05	WTI NYMEX
Jan 12 Dec 12	Natural gas swap	30,000 MMBtu/day	$5.05	IF NYMEX (HH)
Jan 12 Dec 12	Natural gas swap	15,000 MMBtu/day	$5.62	IF PEPL
Jan 12 Mar 12	Liquids swap(1)	1,350,014 Gal/mo	$1.10	OPIS Conway
Jan 12 Mar 12	Liquids swap(1)	1,155,018 Gal/mo	$0.91	OPIS Mont Belvieu
Apr 12 Dec 12	Liquids swap(2)	180,006 Gal/mo	$2.11	OPIS Conway
Apr 12 Jun 12	Liquids swap(3)	1,000,028 Gal/mo	$0.78	OPIS Mont Belvieu
Jul 12 Dec 12	Liquids swap(4)	310,000 Gal/mo	$0.69	OPIS Mont Belvieu

(1) Types of liquids involved are natural gasoline, ethane, propane, isobutane and normal butane.
(2) Types of liquids involved are natural gasoline.
(3) Types of liquids involved are natural gasoline and ethane.
(4) Types of liquids involved are ethane.

Subsequent to December 31, 2011, the following cash flow hedges were entered into:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Mar 12 Dec 12	Crude oil swap	1,000 Bbl/day	$103.90	WTI NYMEX
Jan 13 Dec 13	Crude oil swap	1,000 Bbl/day	$101.63	WTI NYMEX
Jul 12 Sep 12	Natural gas swap	20,000 MMBtu/day	$2.98	IF NYMEX (HH)

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).

Item 8. Financial Statements and Supplementary Data

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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, 2011. 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, 2011, 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, 2011, 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 operations, 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, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, 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, 2011, 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.

As discussed in Note 2 to the consolidated financial statements, at December 31, 2009 the Company changed the manner in which it estimates oil and gas reserves.

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 23, 2012

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UNIT CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	As of December 31, 2011	2010
	(In thousands except share and par value amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 835	$ 1,359
Accounts receivable (less allowance for doubtful accounts of $5,343 and $5,083)	165,276	130,142
Materials and supplies	8,202	6,316
Current derivative asset (Note 13)	31,938	5,568
Current income tax receivable	0	25,211
Current deferred tax asset (Note 8)	10,936	13,537
Prepaid expenses and other	11,278	6,047
Total current assets	228,465	188,180
Property and equipment:		
Drilling equipment	1,423,570	1,273,861
Oil and natural gas properties, on the full cost method:		
Proved properties	3,302,032	2,738,093
Undeveloped leasehold not being amortized	185,632	175,065
Gas gathering and processing equipment	278,919	199,564
Transportation equipment	34,118	31,688
Other	37,544	28,511
	5,261,815	4,446,782
Less accumulated depreciation, depletion, amortization and impairment	2,319,484	2,047,031
Net property and equipment	2,942,331	2,399,751
Deferred offering costs	5,671	0
Goodwill (Note 2)	62,808	62,808
Other intangible assets, net	1,855	3,022
Non-current derivative asset (Note 13)	4,514	2,537
Other assets	11,076	12,942
Total assets	$ 3,256,720	$ 2,669,240
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 143,311	$ 89,885
Accrued liabilities (Note 5)	51,733	30,093
Income taxes payable	781	0
Contract advances	2,055	2,582
Current portion of derivative liabilities (Note 13)	2,657	14,446
Current portion of other long-term liabilities (Note 6)	12,213	10,122
Total current liabilities	212,750	147,128
Long-term debt (Note 6)	300,000	163,000
Non-current derivative liabilities (Note 13)	0	4,359

Other long-term liabilities (Note 6)	113,830	88,030
Deferred income taxes (Note 8)	683,123	556,106
Commitments and contingencies (Note 15)		
Shareholders equity:		
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	0	0
Common stock, $0.20 par value, 175,000,000 shares authorized, 48,151,442 and 47,910,431 shares issued as of December 31, 2011 and 2010, respectively	9,541	9,493
Capital in excess of par value	408,109	393,501
Accumulated other comprehensive income (loss) (net of tax of $11,961 and ($4,243), respectively)	19,026	(6,851)
Retained earnings	1,510,341	1,314,474
Total shareholders equity	1,947,017	1,710,617
Total liabilities and shareholders equity	$ 3,256,720	$ 2,669,240

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

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UNIT CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2011	2010	2009
	(In thousands except per share amounts)		
Revenues:			
Contract drilling	$ 484,651	$ 316,384	$ 236,315
Oil and natural gas	516,316	400,807	357,879
Gas gathering and processing	208,238	154,516	108,628
Other	(834)	10,138	7,076
Total revenues	1,208,371	881,845	709,898
Expenses:			
Contract drilling:			
Operating costs	269,899	186,813	140,080
Depreciation	79,667	69,970	45,326
Oil and natural gas:			
Operating costs	131,271	105,365	87,734
Depreciation, depletion and amortization	183,350	118,793	114,681
Impairment of oil and natural gas properties (Note 2)	0	0	281,241
Gas gathering and processing:			
Operating costs	174,859	122,146	87,908
Depreciation and amortization	16,101	15,385	16,104
General and administrative	30,055	26,152	24,011
Interest, net	4,167	0	539
Total expenses	889,369	644,624	797,624
Income (loss) before income taxes	319,002	237,221	(87,726)
Income tax expense (benefit):			
Current	(2,416)	(9,935)	(223)
Deferred	125,551	100,672	(32,003)
Total income taxes	123,135	90,737	(32,226)
Net income (loss)	$ 195,867	$ 146,484	$ (55,500)
Net income (loss) per common share:			
Basic	$ 4.11	$ 3.10	$ (1.18)
Diluted	$ 4.08	$ 3.09	$ (1.18)

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, 2009, 2010 and 2011

	Common Stock	Capital In Excess of Par Value	Accumulated Other Compre-hensive Income	Retained Earnings	Total
		(In thousands except share amounts)			
Balances, January 1, 2009	$ 9,325	$ 367,000	$ 33,284	$ 1,223,490	$ 1,633,099
Comprehensive income (loss):					
Net loss	0	0	0	(55,500)	(55,500)
Other comprehensive income (loss) (net of tax of $20,430, ($37,560), $340):					
Change in value of cash flow derivative instruments used as cash flow hedges	0	0	32,307	0	32,307
Reclassification derivative settlements	0	0	(61,690)	0	(61,690)
Ineffective portion of derivatives qualifying for cash flow hedge accounting	0	0	557	0	557
Total comprehensive income	0	0	0	0	(84,326)
Activity in employee compensation plans (274,705 shares)	80	16,957	0	0	17,037
Balances, December 31, 2009	9,405	383,957	4,458	1,167,990	1,565,810
Comprehensive income (loss):					
Net income	0	0	0	146,484	146,484
Other comprehensive income (loss) (net of tax of $13,254, ($19,987), ($267)):					
Change in value of cash flow derivative instruments used as cash flow hedges	0	0	21,392	0	21,392
Reclassification derivative settlements	0	0	(32,268)	0	(32,268)
Ineffective portion of derivatives qualifying for cash flow hedge accounting	0	0	(433)	0	(433)
Total comprehensive loss	0	0	0	0	135,175
Activity in employee compensation plans (379,762 shares)	88	9,544	0	0	9,632
Balances, December 31, 2010	9,493	393,501	(6,851)	1,314,474	1,710,617
Comprehensive income (loss):					
Net income	0	0	0	195,867	195,867
Other comprehensive income (loss) (net of tax of $18,412, ($1,146), ($1,061)):					
Change in value of cash flow derivative instruments used as cash flow hedges	0	0	29,384	0	29,384
Reclassification derivative settlements	0	0	(1,819)	0	(1,819)
Ineffective portion of derivatives qualifying for cash flow hedge accounting	0	0	(1,688)	0	(1,688)
Total comprehensive income	0	0	0	0	221,744
Activity in employee compensation plans (241,011 shares)	48	14,608	0	0	14,656

Balances, December 31, 2011	$ 9,541	$ 408,109	$ 19,026	$ 1,510,341	$ 1,947,017

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, 2011	2010	2009
		(In thousands)	
OPERATING ACTIVITIES:			
Net income (loss)	$ 195,867	$ 146,484	$ (55,500)
Adjustments to reconcile net income (loss) to net cash provided (used) by operating activities:			
Depreciation, depletion and amortization	280,451	205,124	177,166
Impairment of oil and natural gas properties (Note 2)	0	0	281,241
Unrealized (gain) loss on derivatives	(2,413)	(1,036)	1,944
(Gain) loss on disposition of assets	595	(9,687)	(6,224)
Deferred tax expense (benefit)	125,551	100,672	(32,003)
Employee stock compensation plans	14,303	10,067	10,708
Bad debt expense	260	0	975
ARO liability accretion	3,838	2,937	2,585
Other, net	294	(69)	(130)
Changes in operating assets and liabilities increasing (decreasing) cash:			
Accounts receivable	(38,731)	(58,965)	116,472
Materials and supplies	(1,886)	598	3,009
Prepaid expenses and other	22,672	6,957	(1,525)
Accounts payable	(1,064)	(8,913)	(7,068)
Accrued liabilities	9,245	(3,555)	(1,410)
Contract advances	(527)	(542)	235
Net cash provided by operating activities	608,455	390,072	490,475
INVESTING ACTIVITIES:			
Capital expenditures	(728,551)	(484,080)	(316,660)
Producing property and other acquisitions	(50,013)	(92,573)	0
Proceeds from disposition of property and equipment	10,328	40,048	44,733
Acquisition of other assets	0	344	0
Net cash used in investing activities	(768,236)	(536,261)	(271,927)
FINANCING ACTIVITIES:			
Borrowings under line of credit	441,500	286,900	95,600
Payments under line of credit	(554,500)	(153,900)	(265,100)
Proceeds from issuance of senior subordinated notes, net of offering costs	243,950	0	0
Proceeds from exercise of stock options	679	149	282
Tax (expense) benefit from stock options	1,174	40	(252)
Increase (decrease) in book overdrafts (Note 2)	26,454	13,219	(48,522)
Net cash provided by (used in) financing activities	159,257	146,408	(217,992)
Net increase (decrease) in cash and cash equivalents	(524)	219	556
Cash and cash equivalents, beginning of year	1,359	1,140	584
Cash and cash equivalents, end of year	$ 835	$ 1,359	$ 1,140

Supplemental disclosure of cash flow information:

Cash paid during the year for:			
Interest paid (net of capitalized)	$ 3,470	$ 0	$ 682
Income taxes	$ 655	$ 3,143	$ 12,302
Changes in accounts payable and accrued liabilities related to purchases of property, plant and equipment	$ (28,036)	$ (29,700)	$ 18,285

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

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 a 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. Carried out by our subsidiary, Unit Drilling Company and its subsidiary, we contract to drill onshore oil and natural gas wells for our own account and for others. Our current contract drilling operations are conducted in the oil and natural gas producing provinces of Oklahoma, Texas, Louisiana, Wyoming, Colorado, Utah, Montana and North Dakota. We provide land contract drilling services for a wide range of customers.

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, Texas, Louisiana, North Dakota and, to a lesser extent, in Arkansas, New Mexico, Wyoming, Montana, Alabama, Kansas, Mississippi, Michigan, Colorado and Pennsylvania 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 subsidiary, we buy, sell, gather, 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.

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

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

bore reaches the negotiated depth as stated in the contract. The entire amount of a loss, if any, is recorded when the loss is deter-minable. 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, 2011, substantially all of our contracts were daywork contracts of which 62 were multi-well and had durations which ranged from six months to three years. These longer term contracts may contain a fixed 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, 2011 and 2010, book overdrafts were $26.5 million and $13.1 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:

	2011	2010 (In thousands)	2009
Drilling:			
QEP Resources, Inc.	22%	28%	35%
Oil and Natural Gas:			
Valero Energy Corporation	18%	7%	5%
Sunoco Partners Marketing	10%	8%	7%
Mid-Stream:			
ONEOK	54%	53%	52%
Gavilon, LLC	19%	12%	0%
ConocoPhillips	7%	12%	15%
Tenaska	1%	7%	17%

We had a concentration of cash of $31.1 million and $23.8 million at December 31, 2011 and 2010, respectively with one bank.

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2011 and determined there was no material risk at that time. At December 31, 2011, 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, 2011 (In millions)
Bank of Montreal	$ 18.7
Bank of America, N.A.	6.5
BNP Paribas	6.1
Comerica Bank	1.4
BBVA Compass Bank	1.0
BP Corporation	0.2
Crédit Agricole Corporate and Investment Bank, London Branch	0.1
Macquarie Bank	(0.2)
Total assets (liabilities)	$ 33.8

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. No significant impairments were recorded at December 31, 2011, 2010 or 2009.

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.

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. No goodwill impairment was recorded for the years ended December 31, 2011, 2010, or 2009. There were no additions to goodwill in 2011, 2010 or 2009. Goodwill of $5.7 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, 2011, 2010 or 2009. Amortization of $1.2 million, $2.6 million and $3.7 million was recorded in 2011, 2010 and 2009, respectively. Accumulated amortization for 2011 and 2010 was $16.1 million and $14.9 million, respectively. Amortization of $1.2 million and $0.7 million is expected to be recorded in 2012 and 2013, respectively.

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 $15.6 million, $13.4 million and $13.2 million were capitalized in 2011, 2010 and 2009, respectively. Independent petroleum engineers annually audit our internal evaluation of our reserves. The average rates used for depreciation, depletion and amortization (DD&A) were $15.06, $11.94 and $11.22 per Boe in 2011, 2010 and 2009, 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 $185.6 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 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%. Starting December 31, 2009, companies like us that use full cost accounting moved from using the commodity prices existing on the last day of the period to that of 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, even if prices are depressed for only a short period of time. Once incurred, a write-down of oil and natural gas properties is not reversible.

We recorded a non-cash ceiling test write-down of $281.2 million pre-tax ($175.1 million, net of tax) during the quarter ending March 31, 2009. This write-down resulted from the reduction in commodity prices existing at the end of the first quarter of 2009 as compared to at the end of 2008. Derivative instruments qualifying as cash

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

flow hedges were included in determining the limitation on the capitalized costs in our March 31, 2009 ceiling test calculation. The effect of including those hedges was a $197.9 million pre-tax increase in the discounted net cash flow of our oil and natural gas properties. Our qualifying cash flow hedges as of March 31, 2009, which consisted of swaps and collars, covered 2009 production of 30.3 Bcfe and 2010 production of 33.2 Bcfe.

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. However, if there are 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. Our qualifying cash flow hedges used in the ceiling test determination at December 31, 2011, consisted of swaps covering 5.0 MMBoe in 2012 and 0.7 MMBoe in 2013. The effect of those hedges on the December 31, 2011 ceiling test was a $22.1 million pre-tax increase in the discounted net cash flows of our oil and natural gas properties. Even without the impact of those hedges, we would not have been required to take a write-down for the quarter. Our oil and natural gas hedging is discussed in Note 13 of the Notes to our Consolidated Financial Statements.

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 $52.2 million, $40.1 million and $15.0 million for 2011, 2010 and 2009, respectively from our contract drilling segment and eliminated the associated operating expense of $32.6 million, $31.0 million and $13.7 million during 2011, 2010 and 2009, respectively, yielding $19.6 million, $9.1 million and $1.3 million during 2011, 2010 and 2009, 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. If a derivative is designated as a cash flow hedge, we 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. Derivatives that do not qualify for hedge treatment are recorded at fair value with gains (losses) recognized in earnings in the period of change.

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

We document our risk management strategy and 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, 2011 balancing position to be approximately 3.4 Bcf on under-produced properties and approximately 3.3 Bcf on over-produced properties. We have recorded a receivable of $1.5 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 $3.3 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.

Improving Disclosures about Fair Value Measurements. In January 2010, the FASB issued ASU 2010-06 *Fair Value Measurements and Disclosures (ASC 820): Improving Disclosures about Fair Value Measurements,* which provides additional guidance to improve disclosures regarding fair value measurements. The ASU amends ASC 820-10, *Fair Value Measurements and Disclosures Overall* (formerly FAS 157, *Fair Value Measurements)* to add two new disclosures: (1) transfers in and out of Level 1 and 2 measurements and the reasons for the transfers, and (2) a gross presentation of activity within the Level 3 roll forward. The ASU also

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

includes clarifications to existing disclosure requirements on the level of disaggregation and disclosures regarding inputs and valuation techniques. The ASU applies to all entities required to make disclosures about recurring and nonrecurring fair value measurements. The effective date of the ASU was the first interim or annual reporting period beginning after December 15, 2009 and was adopted January 1, 2010, except for the gross presentation of the Level 3 roll forward information, which was adopted January 1, 2011. Because it only includes enhanced disclosures, this statement did not have a significant impact on us.

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.

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 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.

Testing Goodwill for Impairment. In August 2011, the FASB issued ASU 2011-08 *Intangibles-Goodwill and Other (ASC 350): Testing Goodwill for Impairment.* This ASU is intended to simplify how entities, both public and nonpublic, test goodwill for impairment. ASU 2011-08 permits an entity to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test described in ASC 350, *Intangibles-Goodwill and Other.* The more-likely-than-not threshold is defined as having a likelihood of more than 50%.

ASU 2011-08 is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011.

NOTE 3 ACQUISITIONS

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

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

horizontal oil play located mainly in Beaver County, Oklahoma. At the time of acquisition, proved developed producing net reserves associated with the 10 acquired producing wells was approximately 762,000 BOE consisting of 511,000 barrels of oil, 155,000 barrels of NGLs and 573 MMcf of natural gas.

Also during the second quarter of 2010, we completed an acquisition from unaffiliated parties consisting of approximately 32,000 net acres of undeveloped oil and gas leasehold located in Southwest Oklahoma and North Texas for approximately $17.6 million.

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 in Oklahoma and Lipscomb County, Texas. The purchase price allocation was $8.4 million for proved properties and $3.9 million for acreage. The net proved developed reserves associated with the acquisition are estimated at 6.6 Bcfe (91% natural gas) with production of 1.7 MMcfe per day. 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, subject to closing adjustments, 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 proved reserves associated with the acquisition are approximately 31.2 Bcfe (99% natural gas), 83% of which is proved developed. The acquisition also included approximately 55,000 net acres of which 96% is held by production.

During the fourth quarter of 2011, we leased approximately 60,000 net acres of undeveloped oil and gas leasehold located in south central Kansas for approximately $17.3 million.

NOTE 4 EARNINGS (LOSS) PER SHARE

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

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
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	0	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, restricted stock and SARs	0	176	(0.01)
Diluted earnings per common share	$ 146,484	47,454	$ 3.09
For the year ended December 31, 2009:			
Basic loss per common share	$ (55,500)	46,990	$ (1.18)
Effect of dilutive stock options and restricted stock	0	0	0
Diluted loss per common share	$ (55,500)	46,990	$ (1.18)

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Due to the net loss for 2009, approximately 373,000 weighted average shares related to stock options, restricted stock and SARs were antidilutive and were excluded from the earnings per share calculation above. 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:

	2011	2010	2009
Options and SARs	105,000	222,901	358,821
Average exercise price	$ 61.24	$ 52.59	$ 47.83

NOTE 5 ACCRUED LIABILITIES

Accrued liabilities consisted of the following as of December 31:

	2011	2010
	(In thousands)	
Employee costs	$ 22,518	$ 16,499
Taxes	13,480	1,310
Lease operating expenses	7,346	6,214
Interest payable	2,647	667
Hedge settlements	1,844	1,634
Other	3,898	3,769
Total accrued liabilities	$ 51,733	$ 30,093

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

Long-Term Debt

As of the dates in the table, long-term debt consisted of the following:

	December 31, 2011	December 31, 2010
	(In thousands)	
Credit agreement with average interest rates, of 2.7% and 3.5% at December 31, 2011 and 2010, respectively	$ 50,000	$ 163,000
6.625% senior subordinated notes due 2021	250,000	0
Total long-term debt	$ 300,000	$ 163,000

Credit Agreement. On September 13, 2011, we entered into a Senior Credit Agreement (credit agreement) that replaces our previous credit agreement which was scheduled to mature on May 24, 2012. The credit agreement has a maturity date of September 13, 2016. The amount available to be borrowed is the lesser of the amount we elect as the commitment amount (currently $250.0 million) or the value of the borrowing base as determined by the lenders (currently $600.0 million), but in either event, not to exceed the maximum credit agreement amount of $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. To date, in connection with this new credit agreement, we paid $1.8 million in origination, agency, syndication and other related fees. We are amortizing these fees over the life of the credit agreement.

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The amount of the borrowing base, which is subject to redetermination 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 amount 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%, and is payable at the end of each month and the principal borrowed may be paid at any time, in part or in whole, without a premium or penalty. At December 31, 2011, all of our $50.0 million in outstanding borrowings were subject to LIBOR.

We used borrowings under the credit agreement to pay off the commitments issued under our previous credit agreement. In addition, 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 of the Borrowers.

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, 2011, 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 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.

The Notes are guaranteed by our wholly-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.

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Notes were issued under an Indenture dated as of May 18, 2011, between us and Wilmington Trust FSB, as Trustee (the Trustee), as supplemented by the First Supplemental Indenture dated as of May 18, 2011, between us, the Guarantors and the Trustee, establishing the terms and providing for the issuance of the Notes (the Supplemental Indenture). The discussion of the Notes in this annual report is qualified by and subject to the actual terms of the Indenture and the First Supplemental Indenture.

The Notes bear interest at a rate of 6.625% per year (payable semi-annually in arrears on May 15 and November 15 of each year), and will mature on May 15, 2021.

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 and the Supplemental Indenture contain customary events of default. The Indenture governing the Notes 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, 2011.

Other Long-Term Liabilities

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

	2011	2010
	(In thousands)	
ARO liability	$ 96,446	$ 69,265
Workers compensation	17,026	17,566
Separation benefit plans	6,845	5,690
Gas balancing liability	3,263	3,263
Deferred compensation plan	2,463	2,368
	126,043	98,152
Less current portion	12,213	10,122
Total other long-term liabilities	$ 113,830	$ 88,030

Estimated annual principle payments under the terms of debt and other long-term liabilities from 2012 through 2016 are $12.2 million, $3.1 million, $20.0 million, $2.9 million and $52.9 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

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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

	2011	2010
	(In thousands)	
ARO liability, January 1:	$ 69,265	$ 56,404
Accretion of discount	3,838	2,937
Liability incurred	15,068(1)	4,768
Liability settled	(1,009)	(763)
Revision of estimates	9,284(2)	5,919(2)
ARO liability, December 31:	96,446	69,265
Less current portion	3,040	1,915
Total long-term ARO liability	$ 93,406	$ 67,350

(1) Liability incurred in 2011 includes new wells acquired.

(2) Plugging liability estimates were revised upward in both 2011 and 2010 due to increases in the cost of services used to plug wells over the preceding years.

NOTE 8 INCOME TAXES

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

	2011	2010	2009
		(In thousands)	
Income tax expense (benefit) computed by applying the statutory rate	$ 111,651	$ 83,027	$ (30,704)
State income tax, net of federal benefit	8,941	6,030	(2,409)
Statutory depletion and other	2,543	1,680	887
Income tax expense (benefit)	$ 123,135	$ 90,737	$ (32,226)

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

	2011	2010	2009
		(In thousands)	
Current taxes:			

Federal	$ (3,159)	$ (6,856)	$ (5,124)
State	743	(3,079)	4,901
	(2,416)	(9,935)	(223)
Deferred taxes:			
Federal	109,363	88,021	(23,510)
State	16,188	12,651	(8,493)
	125,551	100,672	(32,003)
Total provision	$ 123,135	$ 90,737	$ (32,226)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	2011	2010
	(In thousands)	
Deferred tax assets:		
Allowance for losses and nondeductible accruals	$ 53,376	$ 47,742
Net operating loss carryforward	47,683	2,926
Alternative minimum tax credit carryforward	0	0
	101,059	50,668
Deferred tax liability:		
Depreciation, depletion, amortization and impairment	(773,246)	(593,237)
Net deferred tax liability	(672,187)	(542,569)
Current deferred tax asset	10,936	13,537
Non-current deferred tax liability	$ (683,123)	$ (556,106)

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, 2011, we have federal net operating loss carryforwards of approximately $119.8 million which expire from 2015 to 2031.

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 71,742, 74,205 and 202,655 shares of common stock and recognized expense of $4.3 million, $3.6 million and $3.6 million in 2011, 2010 and 2009, 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, 2011 and 2010 was $2.5 million and $2.4 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.

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 $1.9 million, $1.6 million and $1.5 million in 2011, 2010 and 2009, 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, 2010 and 2009) 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.

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	2011	2010	2009
		(In thousands)	
Contract drilling	$ 352	$ 529	$ 368
Well supervision and other fees	$ 396	$ 386	$ 352
General and administrative expense reimbursement	$ 610	$ 536	$ 376

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.

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.

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 12 STOCK-BASED COMPENSATION

For restricted stock awards, stock options and SARs, we had:

	2011	2010 (In millions)	2009
Recognized stock compensation expense	$ 10.0	$ 10.8	$ 9.2
Capitalized stock compensation cost for our oil and natural gas properties	2.5	2.7	2.1
Tax benefit on stock based compensation	3.9	4.1	2.6

The remaining unrecognized compensation cost related to unvested awards at December 31, 2011 is approximately $8.4 million with $1.7 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.

The following table estimates the fair value of each option and SARs granted under all of our plans during the twelve month periods ending December 31, using the Black-Scholes model applying the estimated values presented in the table:

	2011	2010	2009
Options granted	31,500	52,504[(1)]	3,496
Stock appreciation rights	0	0	0
Estimated fair value (in millions)	$ 0.7	$ 0.8	$ 0.1
Estimate of stock volatility	0.48	0.45	0.41
Estimated dividend yield	0%	0%	0%
Risk free interest rate	2%	2%	2%
Expected life range based on prior experience (in years)	5	5	5
Forfeiture rate	0%	0%	5%

(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 employee termination rates within the model and aggregate groups of employees 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.

At our annual meeting on May 3, 2006, our shareholders approved the Unit Corporation Stock and Incentive Compensation Plan. This plan allows for the issuance of 2.5 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;

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

- 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.

During 2009, there were 116,826 shares of other stock-based awards issued under this plan. These shares vested immediately and the fair value on the grant date was $3.3 million.

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, 2009	145,901	$ 46.59
Granted	0	0
Exercised	0	0
Forfeited	0	0
Outstanding at December 31, 2009	145,901	46.59
Granted	0	0
Exercised	0	0
Forfeited	0	0
Outstanding at December 31, 2010	145,901	46.59
Granted	0	0
Exercised	0	0
Forfeited	0	0
Outstanding at December 31, 2011	145,901	$ 46.59

There were no SARs granted in 2011, 2010 or 2009. The SARs expire after 10 years from the date of the grant. In 2011, 2010 and 2009, 33,745, 48,632 and 48,633 shares vested. The aggregate intrinsic value of the 145,901 shares outstanding subject to vesting at December 31, 2011 was $0.2 million with a weighted average remaining contractual term of 5.7 years.

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Number of Shares	Weighted Average Grant Date Price
Nonvested at January 1, 2009	617,148	$ 47.40
Granted	0	0
Vested	(68,836)	46.18
Forfeited	(41,241)	48.69
Nonvested at December 31, 2009	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

The restricted stock awards vest in periods ranging from one to three years, except for a portion of those granted to certain executive officers in the first quarter of 2011. Thirty percent of the shares granted to the designated executive officers, or 20,062 shares (the performance shares), will cliff vest in the first half of 2014. The actual number of performance shares that vest in 2014 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 20,062 restricted shares granted as performance shares. The fair value of the restricted stock granted in 2011 and 2010 at the grant date was $10.8 million and $16.9 million, respectively. There was no restricted stock granted in 2009. The aggregate intrinsic value of the 190,262 shares of restricted stock on their 2011 vesting date was $10.1 million. The aggregate intrinsic value of the 447,961 shares outstanding subject to vesting at December 31, 2011 was $20.8 million with a weighted average remaining life of 1.0 year.

We also have a Stock Option Plan, which provided for 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 become 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 is the fair market value of the common stock on the date of the grant. As a result of the approval of the adoption of the Unit Corporation Stock and Incentive Compensation Plan, no further awards will be made under this plan.

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Activity pertaining to the Stock Option Plan is as follows:

	Number of Shares	Weighted Average Exercise Price
Outstanding at January 1, 2009	228,290	$ 29.68
Granted	0	0
Exercised	(4,065)	23.45
Forfeited	(4,600)	38.60
Outstanding at December 31, 2009	219,625	29.61
Granted	0	0
Exercised	(32,360)	20.35
Forfeited	(2,500)	37.83
Outstanding at December 31, 2010	184,765	31.11
Granted	0	0
Exercised	(42,285)	28.29
Forfeited	(3,500)	53.90
Outstanding at December 31, 2011	138,980	$ 31.39

There were no shares that vested in 2011. The total grant date fair value of the 6,200, and 27,100 shares vesting in 2010 and 2009 was $0.2 million and $1.0 million. The intrinsic value of options exercised in 2011 was $1.3 million. Total cash received from the options exercised in 2011 was $0.4 million.

	Outstanding and Exercisable Options at December 31, 2011		
Exercise Prices	Number of Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price
$19.04	16,400	1.0 years	$ 19.04
$21.50 - $22.95	38,810	1.9 years	$ 22.76
$37.69 - $37.83	83,770	3.0 years	$ 37.80

Options for 138,980, 184,065 and 212,725 shares were exercisable with weighted average exercise prices of $31.39, $31.02 and $29.25 at December 31, 2011, 2010 and 2009, respectively. The aggregate intrinsic value of the 138,980 shares outstanding subject to options at December 31, 2011 was $2.1 million with a weighted average remaining contractual term of 2.5 years.

On May 29, 2009, the compensation committee and board of directors, approved amendments to the existing Unit Corporation 2000 Non-Employee Directors Stock Option Plan. The amendments extended the plan term from May 30, 2010 to May 30, 2017, and increased the aggregate number of shares that may be issued or delivered due to exercise of non-employee director option awards from 210,000 shares of common stock to 510,000 shares of common stock. Under the 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 is the fair market value of the common stock on the date the stock options are granted. The term of each option is 10 years and cannot be increased and no stock options may be exercised during the first six months of its term except in case of death.

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2009	153,000	$ 46.85
Granted	3,496	31.30
Exercised	(13,000)	14.74
Outstanding at December 31, 2009	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	0	0
Outstanding at December 31, 2011	199,500	$ 48.37

The total grant date fair value of the 31,500, 52,504 and 3,496 shares vesting in 2011, 2010 and 2009, respectively, was $0.7 million, $0.8 million and $0.1 million, respectively. The intrinsic value of options exercised in 2011 was $0.4 million. Total cash received from options exercised in 2011 was $0.2 million.

	Outstanding and Exercisable Options at December 31, 2011		
Exercise Prices	Number of Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price
$20.10 - $20.46	14,000	1.1 years	$ 20.37
$28.23 - $41.21	80,500	6.4 years	$ 36.45
$53.81 - $73.26	105,000	6.5 years	$ 61.24

Options for 199,500, 178,500 and 143,496 shares were exercisable with weighted average exercise prices of $48.37, $45.86 and $49.38 at December 31, 2011, 2010 and 2009, respectively. The aggregate intrinsic value of the shares outstanding subject to options at December 31, 2011 was $1.2 million with a weighted average remaining contractual term of 6.1 years.

NOTE 13 DERIVATIVES

Interest Rate Swaps

From time to time we enter into interest rate swaps to manage our exposure to possible future interest rate increases under our credit agreement. Under these transactions we swap the variable interest rate we would otherwise pay on a portion of our bank debt for a fixed interest rate. In May 2011, in association with the

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

repayment of outstanding borrowings under our credit agreement, we terminated our two outstanding interest rate swaps that were previously accounted for as cash flow hedges, resulting in an increase of approximately $1.5 million in interest expense. Approximately $1.1 million of that expense was capitalized and will be amortized over the life of the assets.

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, 2011, our derivative transactions consisted only of swaps. Swaps are where 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.

Oil and Natural Gas Segment:

At December 31, 2011, the following cash flow hedges were outstanding:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Jan 12 Dec 12	Crude oil swap	5,250 Bbl/day	$96.54	WTI NYMEX
Jan 13 Dec 13	Crude oil swap	2,000 Bbl/day	$102.05	WTI NYMEX
Jan 12 Dec 12	Natural gas swap	30,000 MMBtu/day	$5.05	IF NYMEX (HH)
Jan 12 Dec 12	Natural gas swap	15,000 MMBtu/day	$5.62	IF PEPL
Jan 12 Mar 12	Liquids swap (1)	1,350,014 Gal/mo	$1.10	OPIS Conway
Jan 12 Mar 12	Liquids swap (1)	1,155,018 Gal/mo	$0.91	OPIS Mont Belvieu
Apr 12 Dec 12	Liquids swap (2)	180,006 Gal/mo	$2.11	OPIS Conway
Apr 12 Jun 12	Liquids swap (3)	1,000,028 Gal/mo	$0.78	OPIS Mont Belvieu
Jul 12 Dec 12	Liquids swap (4)	310,000 Gal/mo	$0.69	OPIS Mont Belvieu

(1) Types of liquids involved are natural gasoline, ethane, propane, isobutane and normal butane.
(2) Types of liquids involved are natural gasoline.
(3) Types of liquids involved are natural gasoline and ethane.
(4) Types of liquids involved are ethane.

Subsequent to December 31, 2011, the following cash flow hedges were entered into:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Mar 12 Dec 12	Crude oil swap	1,000 Bbl/day	$103.90	WTI NYMEX
Jan 13 Dec 13	Crude oil swap	1,000 Bbl/day	$101.63	WTI NYMEX
Jul 12 Sep 12	Natural gas swap	20,000 MMBtu/day	$2.98	IF NYMEX (HH)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2011	December 31, 2010
		(In thousands)	
Derivatives designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative assets	$ 31,938	$ 5,091
Long-term	Non-current derivative assets	4,514	2,537
Total derivatives designated as hedging instruments		36,452	7,628
Derivatives not designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative assets	0	477
Total derivatives not designated as hedging instruments		0	477
Total derivative assets		$ 36,452	$ 8,105

	Balance Sheet Location	Derivative Liabilities Fair Value December 31, 2011	December 31, 2010
		(In thousands)	
Derivatives designated as hedging instruments			
Interest rate swaps:			
Current	Current portion of derivative liabilities	$ 0	$ 1,139
Long-term	Non-current derivative liabilities	0	475
Commodity derivatives:			
Current	Current portion of derivative liabilities	2,657	13,166
Long-term	Non-current derivative liabilities	0	3,884
Total derivatives designated as hedging instruments		2,657	18,664
Derivatives not designated as hedging instruments			
Commodity derivatives (basis swaps):			
Current	Current portion of derivative liabilities	0	141
Total derivatives not designated as hedging instruments		0	141

Total derivative liabilities	$ 2,657	$ 18,805

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 revenue and the purchases to expense as the underlying transactions are settled. As of December 31, 2011 and 2010, we had a gain of $19.0 million and a loss of $6.9 million, net of tax, respectively, in accumulated OCI.

Based on market prices at December 31, 2011, we expect to transfer a gain of approximately $18.0 million, net of tax, included in accumulated OCI during the next 12 months in the related month of settlement. The commodity derivative instruments existing as of December 31, 2011 are expected to mature by December 2013.

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Certain derivatives do not qualify for designation as cash flow hedges. We had three basis swaps that did not qualify as cash flow hedges that expired in December 2011. For these derivatives, any changes in their fair value occurring before their maturity (i.e., temporary fluctuations in value) are reported in oil and natural gas revenues in our consolidated statements of operations. 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. Any change in fair value resulting from ineffectiveness is recognized in our oil and natural gas revenues.

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)	
	2011	2010
	(In thousands)	
Interest rate swaps	$ 0	$ (996)
Commodity derivatives	19,026	(5,855)
Total	$ 19,026	$ (6,851)

(1) Net of taxes.

Effect of derivative instruments on the Consolidated Statement of Operations (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)	
		2011	2010	2011	2010
		(In thousands)			
Commodity derivatives	Oil and natural gas revenue	$ 4,699	$ 53,473	$ 2,749	$ 700
Interest rate swaps	Interest, net	(1,734)	(1,218)	0	0
	Total	$ 2,965	$ 52,255	$ 2,749	$ 700

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

Effect of Derivative Instruments on the Consolidated Statement of Operations (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 2011	2010
		(In thousands)	
Commodity derivatives (basis swaps)	Oil and natural gas revenue	$ (1,047)	$ 336
Total		$ (1,047)	$ 336

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2011		
	Level 2	Level 3	Total
	(In thousands)		
Financial assets (liabilities):			
Commodity derivatives:			
Assets	$ 9,698	$ 34,321	$ 44,019
Liabilities	(9,518)	(706)	(10,224)
	$ 180	$ 33,615	$ 33,795

	December 31, 2010		
	Level 2	Level 3	Total
	(In thousands)		
Financial assets (liabilities):			
Interest rate swaps	$ 0	$ (1,614)	$ (1,614)
Commodity derivatives:			
Assets	$ 0	$ 11,546	$ 11,546
Liabilities	(19,954)	(678)	(20,632)
	$ (19,954)	$ 10,868	$ (9,086)

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.

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2011		For the Year Ended December 31, 2010	
	Interest Rate Swaps	Commodity Swaps	Interest Rate Swaps	Commodity Swaps
	(In thousands)			
Beginning of period	$ (1,614)	$ 10,868	$ (1,948)	$ 19,948
Total gains or losses (realized and unrealized):				
Included in earnings (loss) (1)	(1,734)	20,086	(1,218)	64,470
Included in other comprehensive income (loss)	1,614	22,503	334	(10,116)
Settlements	1,734	(19,842)	1,218	(63,434)
End of period	$ 0	$ 33,615	$ (1,614)	$ 10,868
Total gains (losses) for the period included in earnings attributable to the change in unrealized gain (loss) relating to assets still held as of December 31, 2011 and 2010	$ 0	$ 244	$ 0	$ 1,036

(1) Interest rate swaps and commodity sales swaps and collars are reported in the consolidated statements of operations in interest expense and revenues, respectively.

Based on our valuation at December 31, 2011, 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, 2011, the carrying values on the consolidated balance sheets for cash and cash equivalents, 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 consideration of our non-performance risk, long-term debt associated with our credit agreement at December 31, 2011 approximates its fair value.

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The carrying amount of long-term debt associated with the Notes reported in the consolidated balance sheet as of December 31, 2011 was $250.0 million. We estimate the fair value of these Notes using quoted marked prices at December 31, 2011 was $250.6 million.

NOTE 15 COMMITMENTS AND CONTINGENCIES

We lease office space or yards in Elmwood, Elk City, Oklahoma City, Quinton and Tulsa, Oklahoma; Canadian and Houston, Texas; Denver and Englewood, Colorado; Pinedale, Wyoming; and Pittsburgh, Pennsylvania under the terms of operating leases expiring through September, 2015. Additionally, we have several 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 $6.2 million, $4.5 million, $1.9 million and $0.2 million in 2012-2015, respectively. Total rent expense incurred was $3.7 million, $1.8 million and $2.1 million in 2011, 2010 and 2009, 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 $22,000 in 2011, $22,000 in 2010 and $1,000 in 2009.

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.

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.

For the next twelve months, we have committed to purchase approximately $6.6 million of new drilling rig components, drill pipe, drill collars and related equipment and $0.3 million remaining towards a gas treating plant.

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

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	2011	2010 (In thousands)	2009
Revenues:			
Contract drilling	$ 536,872	$ 356,527	$ 251,364
Elimination of inter-segment revenue	(52,221)	(40,143)	(15,049)
Contract drilling net of inter-segment revenue	484,651	316,384	236,315
Oil and natural gas	516,316	400,807	357,879
Gas gathering and processing	284,248	201,320	142,491
Elimination of inter-segment revenue	(76,010)	(46,804)	(33,863)
Gas gathering and processing net of inter-segment revenue	208,238	154,516	108,628
Other, net	(834)	10,138	7,076
Total revenues	$ 1,208,371	$ 881,845	$ 709,898
Operating income (loss):			
Contract drilling	$ 135,085	$ 59,601	$ 50,909
Oil and natural gas	201,695	176,649	(125,777)[3]
Gas gathering and processing	17,278	16,985	4,616
Total operating income (loss) [1]	354,058	253,235	(70,252)
General and administrative expense	(30,055)	(26,152)	(24,011)
Interest expense, net	(4,167)	0	(539)
Other income (loss), net	(834)	10,138	7,076
Income (loss) before income taxes	$ 319,002	$ 237,221	$ (87,726)
Identifiable assets:			
Contract drilling	$ 1,118,666	$ 998,658	$ 951,702
Oil and natural gas	1,820,492	1,441,797	1,068,970
Gas gathering and processing	247,763	176,596	163,625
Total identifiable assets [2]	3,186,921	2,617,051	2,184,297
Corporate assets	69,799	52,189	44,102
Total assets	$ 3,256,720	$ 2,669,240	$ 2,228,399
Capital expenditures:			
Contract drilling	$ 162,208	$ 118,806	$ 67,686
Oil and natural gas	580,055	463,870	230,550

Gas gathering and processing	79,355	29,815	9,899
Other	10,791	6,417	474
Total capital expenditures	$ 832,409	$ 618,908	$ 308,609
Depreciation, depletion, amortization and impairment:			
Contract drilling	$ 79,667	$ 69,970	$ 45,326
Oil and natural gas			
Depreciation, depletion and amortization	183,350	118,793	114,681
Impairment of oil and natural gas properties	0	0	281,241(3)
Gas gathering and processing	16,101	15,385	16,104
Other	1,333	976	1,055
Total depreciation, depletion, amortization and impairment	$ 280,451	$ 205,124	$ 458,407

(1) Operating income (loss) is total operating revenues less operating expenses, depreciation, depletion, amortization and impairment and does not include non-operating revenues, general corporate expenses, interest expense or income taxes.

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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)			
2011:				
Revenues	$ 247,405	$ 291,495	$ 323,845	$ 345,626
Gross profit	$ 73,568	$ 89,164	$ 96,581	$ 94,745(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(2)
2010:				
Revenues	$ 206,550	$ 204,603	$ 218,116	$ 252,576
Gross profit	$ 59,319	$ 53,499	$ 63,371	$ 77,046(1)
Net income	$ 36,153	$ 32,175	$ 34,491	$ 43,665
Net income per common share:				
Basic	$ 0.77	$ 0.68	$ 0.73	$ 0.92
Diluted	$ 0.76	$ 0.68	$ 0.73	$ 0.92

(1) Gross profit excludes other revenues, general and administrative expense and interest expense.

(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.

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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:

	2011	2010 (In thousands)	2009
Capitalized costs:			
Proved properties	$ 3,302,032	$ 2,738,093	$ 2,309,193
Unproved properties	185,632	175,065	140,129
	3,487,664	2,913,158	2,449,322
Accumulated depreciation, depletion, amortization and impairment	(1,724,312)	(1,542,352)	(1,424,559)
Net capitalized costs	$ 1,763,352	$ 1,370,806	$ 1,024,763
Cost incurred:			
Unproved properties acquired	$ 70,999	$ 75,739	$ 37,137
Proved properties acquired	50,013	50,000	3,722
Exploration	43,836	48,304	30,547
Development	391,862	279,903	154,579
Asset retirement obligation	23,345	9,924	4,565
Total costs incurred	$ 580,055	$ 463,870	$ 230,550

The following table shows a summary of the oil and natural gas property costs not being amortized at December 31, 2011, by the year in which such costs were incurred:

	2011	2010	2009 (In thousands)	2008 and Prior	Total
Undeveloped Leasehold Acquired	$ 59,691	$ 49,923	$ 17,766	$ 58,252	$ 185,632

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:

	2011	2010 (In thousands)	2009
Revenues	$ 504,739	$ 392,229	$ 352,572
Production costs	(115,400)	(91,143)	(75,214)
Depreciation, depletion, amortization and impairment	(181,960)	(117,793)	(394,942)
	207,379	183,293	(117,584)
Income tax (expense) benefit	(80,048)	(70,110)	43,153

Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 127,331	$ 113,183	$ (74,431)

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

	Oil Bbls	Liquids Bbls (In thousands)	Natural Gas Mcf
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	0	0	0
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)	0	0
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
2009:			
Proved developed and undeveloped reserves:			
Beginning of year	9,699	10,171	450,135
Revision of previous estimates (1)	459	2,793	(57,393)
Extensions and discoveries	2,135	1,996	50,480
Infill reserves in existing proved fields (2)	618	1,174	19,872
Purchases of minerals in place	44	7	30
Production	(1,286)	(1,488)	(44,063)
End of Year	11,669	14,653	419,061

Proved developed reserves:			
Beginning of year	7,508	8,638	355,824
End of year	9,183	11,538	338,217
Proved undeveloped reserves:			
Beginning of year	2,191	1,533	94,311
End of year	2,486	3,115	80,844

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

(2) Previously included in Extensions, discoveries and other additions .

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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:

	2011	2010	2009
		(In thousands)	
Future cash flows	$ 4,583,629	$ 3,745,046	$ 2,403,892
Future production costs	(1,277,856)	(1,054,630)	(777,725)
Future development costs	(340,992)	(303,152)	(195,486)
Future income tax expenses	(952,736)	(799,260)	(433,366)
Future net cash flows	2,012,045	1,588,004	997,315
10% annual discount for estimated timing of cash flows	(924,136)	(732,918)	(450,980)
Standardized measure of discounted future net cash flows relating to proved oil, NGLs and natural gas reserves	$ 1,087,909	$ 855,086	$ 546,335

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

	2011	2010	2009
		(In thousands)	
Sales and transfers of oil and natural gas produced, net of production costs	$ (389,339)	$ (301,086)	$ (277,358)
Net changes in prices and production costs	115,852	379,097	(145,839)
Revisions in quantity estimates and changes in production timing	(38,336)	(67,116)	(54,327)
Extensions, discoveries and improved recovery, less related costs	401,134	340,771	136,695
Changes in estimated future development costs	37,742	15,974	100,304
Previously estimated cost incurred during the period	45,327	45,327	16,301
Purchases of minerals in place	58,567	42,280	1,288
Sales of minerals in place	(29)	(120)	0
Accretion of discount	128,492	77,536	89,256
Net change in income taxes	(60,675)	(200,815)	39,062
Other net	(65,912)	(23,097)	16,479
Net change	232,823	308,751	(78,139)
Beginning of year	855,086	546,335	624,474
End of year	$ 1,087,909	$ 855,086	$ 546,335

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.

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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, 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, 2011, future cash flows were computed by applying the unescalated 12-month average prices of $96.19 per barrel for oil, $61.78 per barrel for NGLs and $4.12 per Mcf for natural gas, adjusted for price differentials, relating to proved reserves and to the year-end quantities of those reserves. Prior to 2009, the price was based on the single-day period-end price. 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.

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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, 2011.

The effectiveness of the company s internal control over financial reporting as of December 31, 2011, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

(c) **Changes in Internal Control Over Financial Reporting**

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.

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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 2, 2012.

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 13, 2011. 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 10, 2012 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	57	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	54	Senior Vice President since December 2002, General Counsel and Corporate Secretary since January 1987
David T. Merrill	51	Chief Financial Officer and Treasurer since February 24, 2004, Vice President of Finance from August 2003 to February 24, 2004
Brad J. Guidry	56	Executive Vice President, Unit Petroleum Company since March 1, 2005
John Cromling	64	Executive Vice President, Unit Drilling Company since April 15, 2005
Robert Parks	57	Manager and President, Superior Pipeline Company, L.L.C. since June 1996
Richard E. Heck	51	Vice President, Safety, Health and Environment since January 2008
Don A. Hayes	52	Vice President, Controller since January 2012
David Dunham	32	Vice President of Corporate Planning since January 2012

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

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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.

Mr. Schell joined the company in January 1987, as its Secretary and General Counsel. In December 2002, he was elected to the additional position as Senior Vice President. From 1979 until joining the company, 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 Law School. He is a member of the Oklahoma and American Bar Association as well as being a member of the American Corporate Counsel. He also serves as a director of the Oklahoma Independent Producers Association.

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. 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.

Mr. Heck joined Unit Drilling Company in March 2005 as Director of Safety, Health and Environment. In January 2008, he was promoted to the position of Vice President, Safety, Health and Environment for Unit Corporation. From 2001 through 2003 Mr. Heck was a Senior Safety and Loss Prevention Manager with the Williams Companies. From 1998 to 2001 he served as Director of Safety, Health and Environment for MAPCO s Thermogas Company. Mr. Heck worked with Union Oil Company of California from 1984 to 1998. He started his career with Union Oil as a drilling engineer prior to serving in various safety, health and environmental positions. Mr. Heck graduated from the New Mexico Institute of Mining and Technology with a Bachelor of Science Degree in Petroleum Engineering.

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Mr. Hayes joined the company in October 1984 and served as a staff accountant in taxation and drilling accounting until May 1989 when he was promoted to Financial Reporting Supervisor. In September 2003 he was promoted to Assistant Controller and held that position until he became the Controller in September 2008. He became Vice President, Controller in January 2012. He began his career as a staff accountant at Jim Elliot, CPA in Tulsa from August 1982 until joining Unit. Mr. Hayes received a Bachelor of Science Degree in Accounting from Oklahoma State University in 1981 and a Masters Degree in Accounting from Oklahoma State University in 1982 and is a Certified Public Accountant.

Mr. Dunham joined the company in November 2007 as Director of Corporate Planning. In January 2012, he was promoted to the position of Vice President of Corporate Planning for Unit Corporation. From 2004 through 2007, Mr. Dunham served as Manager Structure and Financial Analysis for Williams Power, a subsidiary of the Williams Companies. From 2002 to 2004, he was a Mergers, Acquisitions and Strategic Planning Analyst at Leggett & Platt, Inc. He began his career as a Trading Analyst at Williams Energy Marketing & Trading. Mr. Dunham received his Bachelor of Science degree in Psychology and the Honors Program in Medical Education from Northwestern University, his Master of Science in Finance degree from The University of Tulsa and his MBA from The Wharton School of the University of Pennsylvania.

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).

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, 2011, 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)	338,480(2)	$ 41.40	1,491,616(3)
Equity compensation plans not approved by security holders	0	0	0
Total	338,480	$ 41.40	1,491,616

(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:

138,980 stock options outstanding under the company s Amended and Restated Stock Option Plan.

199,500 stock options outstanding under the Non-Employee Directors Stock Option Plan.

(3) This number reflects 230,000 shares available for issuance under the Non-Employee Directors Stock Option Plan and 1,261,616 shares available for issuance under the Unit Corporation Stock and Incentive Compensation Plan. No more than 2,000,000 of the shares available under the Unit Corporation Stock and Incentive Compensation 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, cancelled, 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.

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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).

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, 2011 and 2010

Consolidated Statements of Operations for the years ended December 31, 2011, 2010 and 2009

Consolidated Statements of Changes in Shareholders Equity for the years ended December 31, 2009, 2010 and 2011

Consolidated Statements of Cash Flows for the years ended December 31, 2011, 2010 and 2009

Notes to Consolidated Financial Statements

2. *Financial Statement Schedules:*
Included in Part IV of this report for the years ended December 31, 2011, 2010 and 2009:

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 Form S-3 (file No. 333-83551), 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 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).

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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).
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 (incorporated herein by reference to Appendix A to the Company s Proxy Statement for its 2006 Annual Meeting filed on March 29, 2006).
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).
10.2.1	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).

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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).

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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).
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, 2011	$ 5,083	$ 260	$ 0	$ 5,343
Year ended December 31, 2010	$ 5,186	$ 0	$ (103)	$ 5,083
Year ended December 31, 2009	$ 4,893	$ 975	$ (682)	$ 5,186

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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 23, 2012

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 23rd day of February, 2012.

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**	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

EXHIBIT INDEX

Exhibit No.	Description
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31.2	Certification of Chief Financial Officer under Rule 13a 14(a) of the Exchange Act.
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101.LAB	XBRL Taxonomy Extension Labels Linkbase Document.
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