

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, 2009

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

(State or other jurisdiction of incorporation or organization)

73-1283193

(I.R.S. Employer Identification No.)

7130 South Lewis, Suite 1000

Tulsa, Oklahoma

(Address of principal executive offices)

74136

(Zip Code)

(Registrant's telephone number, including area code) (918) 493-7700

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

<u>Title of each class</u>	<u>Name of each exchange on which registered</u>
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 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

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 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 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.

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 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

As of June 30, 2009, 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, 2009) held by non-affiliates was approximately \$840,731,739. 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.

<u>Class</u>	<u>Outstanding at February 12, 2010</u>
Common Stock, \$0.20 par value per share	47,592,327 shares

DOCUMENTS INCORPORATED BY REFERENCE

Document
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 5, 2010. The Proxy Statement shall be filed within 120 days after the end of the fiscal year to which this report relates.

Parts Into Which Incorporated
Part III

**FORM 10-K
UNIT CORPORATION**

TABLE OF CONTENTS

	<u>Page</u>
PART I	
Item 1. Business	1
Item 1A. Risk Factors	19
Item 1B. Unresolved Staff Comments	32
Item 2. Properties	32
Item 3. Legal Proceedings	32
Item 4. Submission of Matters to a Vote of Security Holders	32
PART II	
Item 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	32
Item 6. Selected Financial Data	34
Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation	35
Item 7A. Quantitative and Qualitative Disclosures about Market Risk	60
Item 8. Financial Statements and Supplementary Data	62
Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	98
Item 9A. Controls and Procedures	98
Item 9B. Other Information	99
PART III	
Item 10. Directors, Executive Officers and Corporate Governance	99
Item 11. Executive Compensation	101
Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	102
Item 13. Certain Relationships and Related Transactions, and Director Independence	102
Item 14. Principal Accounting Fees and Services	103
PART IV	
Item 15. Exhibits, Financial Statement Schedules	103
Signatures	108
Exhibit Index	109

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.

BOKF – Bank of Oklahoma Financial Corporation.

Btu - British thermal unit, used in terms of 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.

CEGT - Center Point Energy Gas Transmission

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 and/or NGLs to six Mcf of natural gas.

MMBbls - Million barrels of crude oil or other liquid hydrocarbons.

MMBtu - Million Btu's.

MMcf - Million cubic feet of natural gas.

MMcfe - Million cubic feet of natural gas equivalent. Determined using the ratio of one barrel of crude oil and/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.

DEFINITIONS – (Continued)

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 to the identification by geologists and geophysicists of 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.

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 and 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.

UNIT CORPORATION
Annual Report
For The Year Ended December 31, 2009

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 Corporation and, as appropriate, Unit Corporation and/or one or more of its subsidiaries.

Our executive offices are at 7130 South Lewis, Suite 1000, Tulsa, Oklahoma 74136; our telephone number is (918) 493-7700. In addition to our executive offices, we have offices or yards in Oklahoma City, Oklahoma; Borger, Houston and Humble, Texas; Englewood and Denver, Colorado; Pinedale, Wyoming; and Pittsburgh, Pennsylvania.

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. Our operations are generally conducted through our three principal wholly owned subsidiaries:

- Unit Drilling Company – which drills onshore oil and natural gas wells for others and for our own account (contract drilling),
- Unit Petroleum Company – which explores, develops, acquires and produces oil and natural gas properties for our own account (oil and natural gas), and
- Superior Pipeline Company, L.L.C. – which buys, sells, gathers, processes and treats natural gas for third parties and for our own account (mid-stream).

Each of these three principal subsidiaries may conduct operations through subsidiaries of their own.

The following table provides certain information about us as of February 12, 2010:

Number of drilling rigs owned	129
Completed gross wells in which we own an interest	7,851
Number of natural gas treatment plants owned	3
Number of processing plants owned	8
Number of natural gas gathering systems owned	33

NOTABLE EVENTS

2009 highlights include:

Contract Drilling

- Added a new 1,500 horsepower diesel electric drilling rig to our fleet while selling three inactive mechanical drilling rigs, bringing our rig fleet to a total of 130 rigs at year end.
- Initiated a program to refurbish and upgrade certain of our drilling rigs to meet the increase in horizontal drilling activity of our customers.
- Actively operating in many of the unconventional gas and shale plays in the U.S. during 2009, including the Haynesville Shale in Northwest Louisiana and East Texas, Cana Woodford Shale in Oklahoma, Granite Wash in the Texas Panhandle, Greater Green River Basin/Pinedale Anticline of Western Wyoming and the Bakken Shale in North Dakota. Contracts have been awarded for the return of three rigs to the Barnett Shale and two rigs moving into the Eagle Ford Shale plays in central and south Texas.

Oil and Natural Gas

- Attained net proved oil, NGLs and natural gas reserves of 577.0 Bcfe, a 1% increase over its proved oil, NGLs and natural gas reserves at the end of 2008.
- Recognized favorable commodity hedge settlements of approximately \$96.0 million.
- Increased drilling activity during the later part of the year given significantly reduced well costs and started a development drilling plan heavily concentrated on horizontal wells.

Mid-Stream

- Began the construction of a second processing facility in the Texas Panhandle.
- Added an additional 69 miles of pipeline (approximately a 9% increase) and connected 37 new wells to its gathering systems.

Corporate

- Reduced long-term debt from approximately \$200.0 million at December 31, 2008 to \$30.0 million at December 31, 2009.

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. Effective January 30, 2009, Leonard Hudson Drilling Co., Inc. another subsidiary of Unit Drilling Company was merged into Unit Texas Drilling L.L.C. Through these companies we drill onshore natural gas and oil 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 and North Dakota.

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

	<u>Year Ended December 31,</u>		
	<u>2009</u>	<u>2008</u>	<u>2007</u>
Number of drilling rigs owned at end of period	130.0	132.0	129.0
Average number of drilling rigs owned during period	130.8	130.4	123.8
Average number of drilling rigs utilized	38.9	103.1	99.4
Utilization rate (1)	30%	79%	80%
Average revenue per day (2)	\$ 16,662	\$ 16,498	\$ 17,291
Total footage drilled (feet in 1,000's)	4,627	11,734	10,453
Number of wells drilled	409	1,028	996

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

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

Description and Location of Our Drilling Rigs. A land 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, such as engines, mud pumps and drill pipe, must be replaced or rebuilt on a periodic basis. Other components, such as 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 2009, 82 of our 130 available drilling rigs were used in drilling services.

The following table shows certain information about our drilling rigs (including their distribution) as of February 12, 2010:

Region	Contracted Rigs	Non-Contracted Rigs	Total Rigs	Average Rated Drilling Depth (ft)
Anadarko Basin Oklahoma	14	16	30	17,483
Panhandle of Texas	11	28	39	14,449
Arkoma Basin	4	5	9	14,722
East Texas, Gulf Coast and North Texas Barnett Shale	18	8	26	16,269
Rocky Mountains	14	11	25	18,360
Totals	61	68	129	16,298

With the dramatic 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 in an effort to minimize cost and streamline operating efficiencies. Currently our operating divisions consist of the following: Panhandle, Arkoma, Gulf Coast, Mid-continent, Woodward, and Rocky Mountain.

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 2009, our Mid-Continent and Woodward divisions marketed 45 drilling rigs in the Anadarko Basin including part of the Texas Panhandle. These two divisions averaged 10 and four drilling rigs operating during 2009, respectively.

Panhandle of Texas. During 2009, we marketed 23 drilling rigs through our Panhandle division. Only four drilling rigs operated during the year in this division. We remain the largest drilling contractor in the combined Anadarko Basin of Oklahoma and the Texas Panhandle in terms of total rig count.

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 2009, Our Arkoma division marketed 11 drilling rigs with an average of two drilling rigs operating.

East Texas, Louisiana, Gulf Coast and the North Texas Barnett Shale. 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 and East Texas. During 2009 our North Texas division was consolidated into the Gulf Coast division. The Gulf Coast division marketed 25 drilling rigs during 2009, with an average of nine drilling rigs operating for the year. The increased interest in the Haynesville Shale play provided an opportunity for us to reposition one drilling rig during the year into this active market area and we added a new 1,500 horsepower rig at the end of 2009.

North Central Texas is the home of the Barnett Shale, a tight gas bearing formation. It is touted as one of the largest natural gas fields in the U.S., and as being one of the first unconventional shale gas formations to have been unlocked by technological advances in the use of multi-stage high pressure fracturization completion processes.

Due to the downturn in rig activity in the Barnett Shale during 2009, we did not operate any rigs in this market. Three rigs recently secured contracts to begin operations in the Barnett Shale in the first quarter of 2010.

Rocky Mountains. The Rocky Mountain area 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 has 26 drilling rigs of which it operated an average of 10 drilling rigs during 2009. We have drilling rigs operating in the Pinedale Anticline of western Wyoming and the Uintah Basin in eastern Utah, as well as other areas throughout this expansive geographical area. An additional drilling rig was moved into the Bakken Shale in North Dakota during the year, and a new 1,500 horsepower rig is being mobilized into this play during the first quarter of 2010.

At any given time our ability to use all of our drilling rigs 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. In 2007, our average utilization rate was 80%. In late 2008, our utilization rate was significantly affected by the U.S. and world economic downturn. For the first nine months of 2008 our average utilization rate was 81%, by December 2008, our average utilization rate had declined to 61%. For 2009, our average utilization rate declined to 30%. This decline in drilling rig utilization reduced the competition for labor during 2009 which in turn reduced the upward pressure on our labor costs.

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

	<u>2009</u>	<u>2008</u>	<u>2007</u>
First quarter	52.8	100.6	96.8
Second quarter	31.6	104.5	97.9
Third quarter	34.6	110.7	100.3
Fourth quarter	36.7	96.7	102.7

Drilling Rig Fleet. The following table summarizes the changes made to our drilling rig fleet during 2009. A more complete discussion of these changes follows the table:

Drilling rigs owned at December 31, 2008	132
Drilling rigs sold during 2009	(3)
Drilling rigs purchased during 2009	1
Drilling rigs constructed during 2009	—
Total drilling rigs owned at December 31, 2009	<u>130</u>

Acquisitions and Construction. During the second quarter of 2008, we completed the construction of two new 1,500 horsepower diesel electric drilling rigs for approximately \$32.2 million and placed these drilling rigs into service in our Rocky Mountain division. During the fourth quarter of 2008, we completed the construction of another new 1,500 horsepower diesel electric drilling rig for approximately \$14.1 million and placed this drilling rig into service in North Dakota.

We negotiated with our equipment suppliers postponement or cancellation of orders where possible; however, during 2008 we paid approximately \$31.7 million for the purchase of major components that we intended to use in the construction of the eight new drilling rigs. We plan to maintain this equipment for future use.

During the first quarter 2009, we sold one 750 horsepower mechanical drilling rig for \$3.1 million and recorded a \$0.9 million gain. During the third quarter 2009, we sold a 1,000 horsepower mechanical drilling rig for \$2.8 million and recorded a \$1.9 million gain. During the fourth quarter 2009, we sold a 1,000 horsepower mechanical drilling rig for \$2.7 million and recorded a \$2.0 million gain and acquired one new 1,500 horsepower diesel electric drilling rig for \$13.2 million.

We agreed to delay the delivery of a new 1,500 horsepower diesel electric drilling rig that was to have been delivered to North Dakota under a long term contract in the first quarter of 2009. Under that agreement, our customer agreed to make monthly payments pending the future delivery of the rig. Our customer has now advised us to prepare the rig for mobilization to North Dakota for use in their drilling program during the first quarter of 2010.

In January and February 2010, our contract drilling segment entered into contracts to sell eight of its idle mechanical drilling rigs to an unaffiliated third party. These drilling rigs ranged in horse power from 800 to 1,000. The closing on three of these drilling rigs occurred in February. Three more are scheduled to close during the first quarter of 2010 with the last transaction for the remaining two rigs anticipated to close during the second quarter of 2010. Proceeds from the sale of all the drilling rigs will be \$23.9 million resulting in an estimated gain of \$6.1 million. The proceeds from this sale will be used to refurbish and upgrade additional rigs in our fleet in order that those rigs can 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. At completion of the sale of the eight rigs and with the additional rig recently placed into service, this segment will have 123 drilling rigs in its fleet.

Over half of our drilling rig fleet is currently equipped to drill horizontal wells common in the unconventional oil and gas plays, while the balance of the fleet is equipped to drill the more conventional vertical and directional type wells. These drilling rigs can be modified to drill the horizontal type wells, which is why we have allocated a portion of our 2010 capital budget to refurbish eight drilling rigs for this purpose.

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 termination by the customer on short notice and on 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. 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. To date, we have not experienced significant losses in performing turnkey contracts. In 2009, 2008 and 2007, we did not drill any turnkey wells. The majority of our work in 2009 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 a small portion under term contracts. Term contracts range from six months to two years in length of term and depending on the contract, the rates can either be fixed throughout the term or allow for adjustment at periodic intervals.

Customers. During 2009, Questar Corporation was our largest drilling customer accounting for approximately 35% of our total contract drilling revenues. No other third party customer accounted for 10% or more of our contract drilling revenues. During 2009, 2008 and 2007, we drilled 38, 122 and 77 wells, respectively, for our oil and natural gas segment. As required by the SEC, the profit received by our contract drilling segment when it drills wells for our oil and natural gas segment is used to reduce the carrying value of our oil and natural gas properties rather than being included in our operating profit. As a result, for 2009, 2008 and 2007 we reduced the carrying value of our oil and gas properties by \$1.3 million, \$27.9 million and \$22.7 million, respectively.

OIL AND NATURAL GAS

General. In 1979, we began to develop our exploration and production operations as a means of diversifying our operations. 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 and New Mexico and, to a lesser extent, in Arkansas, North Dakota, Colorado, Wyoming, Montana, Alabama, Kansas, Mississippi, Michigan, Pennsylvania, Maryland 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, 2009:

<u>Property/Area</u>	<u>Number of Gross Wells</u>	<u>Number of Net Wells</u>	<u>2009 Average Net Daily Production</u>		
			<u>Natural Gas (Mcf)</u>	<u>Oil (Bbls)</u>	<u>NGL (Bbls)</u>
Western division (consists principally of the Rocky Mountain region, New Mexico, Western and Southern Texas and the Gulf Coast region)	3,235	527.34	33,959	1,774	1,915
East division (consists principally of the Appalachian region, Arkansas, East Texas, Northern Louisiana and Eastern Oklahoma)	1,112	272.38	40,107	36	14
Central division (consists principally of Kansas, Western Oklahoma and the Texas Panhandle)	3,503	842.19	46,655	1,713	2,149
Total	<u>7,850</u>	<u>1,641.91</u>	<u>120,721</u>	<u>3,523</u>	<u>4,078</u>

Description and Location of Our Core Operations

West division. Segno Wilcox is located primarily in Polk, Tyler and Hardin counties, Texas, our Segno prospect continues to grow as we have expanded our prospect area to the south by entering into a joint exploration agreement with an unaffiliated third-party for the use of a proprietary 3-D seismic survey covering approximately 151 square miles. We plan to drill three Wilcox wells during the first half of 2010 and pay certain leasehold extensions in order to earn working interest in the wells, the acreage block (approximately 29,000 gross acres) and a license to the 3-D seismic data. For 2009, we completed eight wells at an average working interest of 86% and a 75% success rate. The average completed gross well cost was approximately \$2.7 million per well with average estimated gross reserves of 3.0 Bcfe per well. For 2010, we plan on drilling 23 gross (17.5 net) wells in this division with an approximate total net cost of \$48.0 million dollars.

East division. In the Haynesville shale, we have two areas of activity located in Shelby and Harrison counties, East Texas. In 2009, we have drilled 15 gross vertical wells and one gross horizontal well at a total approximate net cost of \$38.7 million. We own an average of 65% working interest in the vertical wells which have an average gross well cost of \$3.1 million per well. The estimated reserves on a per well basis is 0.7 Bcfe from several different formations including the Cotton Valley Lime, Haynesville Shale, Travis Peak and Pettit formations. The decision to drill vertical wells was primarily based on leasehold obligations that were required to maintain leases. In Harrison County, we drilled and operated our first horizontal Haynesville well during the latter part of 2009 at an approximate cost of \$6.7 million. The well penetrated approximately 3,000' of Haynesville Shale and is scheduled to be fracture stimulated in seven stages with approximately 300,000 pounds of sand per stage. The first three stages have recently been successfully pumped and the remaining four stages will be pumped near the end of the first quarter of

2010. For 2010, we anticipate participating in five horizontal Haynesville wells and two vertical wells at an approximate total net cost of \$31.0 million. We own approximately 16,200 gross and 11,300 net acres in Shelby County and 20,000 gross and 8,700 net acres in Harrison County.

In the Marcellus Shale, of our 197,000 gross and 49,500 net acres, 94% is located in Somerset County, PA. During 2009, we participated with a 25% working interest in three vertical wells and two horizontal wells at a total net cost of \$7.3 million. The vertical wells were drilled in three distinct prospect areas to gather core and log data across a large portion of the leasehold and aid in the selection of the drilling location for the two horizontal wells. Both horizontal wells have been drilled to total depth and achieved lateral lengths of approximately 3,500'. The first horizontal well has recently been fracture stimulated in seven stages with 500,000 pounds of sand per stage. We are in the early phase of analyzing the frac and test data and are conducting an extended flow test into the gas sales line. The second horizontal well is scheduled to be fracture stimulated in the second quarter of 2010.

Central division. We concentrate our Granite Wash (GW) drilling program primarily in the Texas Panhandle portion of the play. In 2009, we drilled and operated 13 vertical wells and one horizontal well. The vertical wells had an average working interest of 66% and estimated gross reserves of 1.8 Bcfe per well at an average gross completed well cost of \$2.3 million per well. We have a 70% working interest in the horizontal GW well with estimated gross reserves of 6.0 to 8.0 Bcfe at an approximate gross completed well cost of \$3.8 million. The well has a 4,000' lateral that was fracture stimulated in 11 stages utilizing 48,000 bbls of water and 1,000,000 pounds of sand. Peak production averaged 4.2 MMcf per day of natural gas, 600 bbls of liquids per day, and 500 bbls of oil per day over a 30 day period beginning in late December 2009. For 2010, we plan on participating in approximately nine gross vertical wells and 31 gross horizontal wells at a total net cost of approximately \$70.0 million. The estimated average working interest for the 2010 wells is approximately 45% and we anticipate operating 21 of those wells. We own approximately 95,000 gross and 38,000 net acres in the GW play.

Acquisitions. On January 18, 2008, we purchased a 50% interest in a 6,800 gross-acre leasehold that we did not already own in our Segno area of operations located in Hardin County, Texas. Included in this purchase were five producing wells with 4.9 Bcfe of then estimated proved reserves and production of 2.8 MMcf of natural gas per day and 88.2 barrels of condensate. The purchase price was \$16.8 million of which \$15.8 million was allocated to the reserves of the wells and \$1.0 million was allocated to the undeveloped leasehold.

In September 2008, we completed an acquisition consisting of a 75% working interest in four producing wells and other proved undeveloped properties for \$22.2 million along with working interests in undeveloped leasehold valued at approximately \$3.5 million, all located in the Texas Panhandle region.

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.

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,					
	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Wells drilled:						
Exploratory:						
Oil	2	0.28	3	1.45	2	0.50
Natural gas	3	2.50	5	4.18	6	4.43
Dry	3	2.10	7	2.60	5	2.32
	<u>8</u>	<u>4.88</u>	<u>15</u>	<u>8.23</u>	<u>13</u>	<u>7.25</u>
Development:						
Oil	20	5.34	55	26.62	15	5.45
Natural gas	64	30.73	182	85.49	197	69.30
Dry	3	1.56	26	13.97	28	14.64
	<u>87</u>	<u>37.63</u>	<u>263</u>	<u>126.08</u>	<u>240</u>	<u>89.39</u>
Total	<u>95</u>	<u>42.51</u>	<u>278</u>	<u>134.31</u>	<u>253</u>	<u>96.64</u>

	Year Ended December 31,					
	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Oil and natural gas wells producing or capable of producing:						
Oil	2,655	409.33	2,665	418.27	2,612	392.99
Natural gas	5,048	1,160.98	5,015	1,151.84	4,855	1,077.38
Total	<u>7,703</u>	<u>1,570.31</u>	<u>7,680</u>	<u>1,570.11</u>	<u>7,467</u>	<u>1,470.37</u>

As of February 12, 2010, we had participated in 10 gross (4.35 net) wells started during 2010.

Cost incurred for development drilling includes \$24.5 million, \$89.4 million and \$52.7 million in 2009, 2008 and 2007, respectively, to develop booked proved undeveloped oil and natural gas reserves.

The following table summarizes our oil and natural gas leasehold acreage for each of the years indicated:

	Year Ended December 31,					
	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Developed acreage	1,060,108	321,715	1,042,602	314,519	1,022,788	299,734
Undeveloped acreage	753,885	294,429 (1)	809,977	316,147	441,726	227,589

(1) Approximately 70% of the net undeveloped acres are covered by leases that will expire in the years 2010 - 2012 unless drilling or production extends the terms of the leases.

The future estimated development costs necessary to develop our proved undeveloped oil and natural gas reserves in the United States for the years 2010, 2011 and 2012, as disclosed in our December 31, 2009 oil and natural gas reserve report, are \$82.2 million, \$72.9 million and \$10.9 million, respectively.

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

	Year Ended December 31,		
	2009	2008	2007
Average sales price per barrel of oil produced:			
Price before hedging	\$ 56.64	\$ 98.02	\$ 70.61
Effect of hedging	(0.31)	(4.15)	—
Price including hedging	<u>\$ 56.33</u>	<u>\$ 93.87</u>	<u>\$ 70.61</u>
Average sales price per barrel of NGLs produced:			
Price before hedging	\$ 25.66	\$ 47.38	\$ 45.01
Effect of hedging	(2.85)	0.04	0.02
Price including hedging	<u>\$ 22.81</u>	<u>\$ 47.42</u>	<u>\$ 45.03</u>
Average sales price per Mcf of natural gas produced:			
Price before hedging	\$ 3.26	\$ 7.53	\$ 6.24
Effect of hedging	2.33	0.09	0.06
Price including hedging	<u>\$ 5.59</u>	<u>\$ 7.62</u>	<u>\$ 6.30</u>
Oil production (MBbls)	1,286	1,261	1,091
NGL production (MBbls)	1,488	1,388	785
Natural gas production (MMcf)	44,063	47,473	43,464
Total production (MMcfe)	60,709	63,368	54,720
Average production cost per equivalent Mcf	\$ 1.45	\$ 1.86	\$ 1.69

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

	Year Ended December 31,		
	2009	2008	2007
Oil (MBbls)	11,669	9,699	9,676
Natural gas liquids (MBbls)	14,653	10,171	6,149
Natural gas (MMcf)	419,061	450,135	419,616
Total proved reserves (MMcfe)	576,990	569,353	514,569

The recent SEC rules for reserve disclosures went into effect for the fiscal year ended December 31, 2009. 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 our reserves as 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 estimates of reserves were audited were reserves that comprised the top 85% of the total proved 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, 2009.

Our Reservoir Engineering department is responsible for reserve determination for all wells in which we have an interest. Their primary objective is to accurately 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 incorporated into the reservoir engineering database and the 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 is the technical person designated to be in responsible charge on behalf of Ryder Scott for our audit of reserves.

Mr. Richoux, an employee of Ryder Scott since 1978, is Ryder Scott's Executive Vice President, serves as Director for Canadian Operations, is a member of the Board of Directors, and 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. For more information regarding Mr. Richoux's geographic and job specific experience, please refer to the Ryder Scott Company website at <http://www.ryderscott.com/Experience/Employees.php>.

Mr. Richoux earned a Bachelor of Science degree in Electrical Engineering from the University of Louisiana at Lafayette in 1967 and is a registered Professional Engineer in the State of Texas and in the Province of Alberta. He is also a member of the Society of Petroleum Engineers (SPE) 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 of his 2009 continuing education hours, Mr. Richoux attended an internally presented 16 hours of formalized training as well as a day-long public forum and various professional society presentations specifically on the new SEC regulations relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register. Mr. Richoux attended an additional nine hours of formalized in-house training as well as nine hours of formalized external training during 2009 covering such topics as the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering, geosciences and petroleum economics evaluation methods, procedures and software and ethics for consultants. In addition, Mr. Richoux served as the technical presenter in a webinar hosted by a major accounting firm relating to the SEC reserve reporting guidelines.

Based on his educational background, professional training and more than 40 years practical experience in the estimation and evaluation of petroleum reserves, Mr. Richoux has attained the professional qualifications as a Reserve Estimator and Reserve Auditor 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.

Unit Corporation – Responsibility for overseeing the preparation of Unit's reserve report is shared by reservoir engineers Robert Lyon and Trenton Mitchell.

Mr. Lyon received a Bachelor of Science degree in Petroleum Engineering from the University of Tulsa in 1972 and has spent 31 of his 38 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 Society of Petroleum Engineers.

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. 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 SPE since 1991.

As part of the continuing education requirement for maintaining their professional licenses Mr. Lyon and Mr. Mitchell 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.

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.

As of December 31, 2009, we had approximately 156 gross proved undeveloped wells (PUDs) all of which we have plans to develop within the next five years for a net cost of approximately \$160.0 million. We do not have any material aged PUDs (PUDs greater than five years). Our aged PUDs represent 0.6% of our total proved reserves and 3% of our total PUDs, the majority of which have already been drilled in 2010. During 2009, we converted 16 PUDs into proved developed wells (PDPs) at a cost of approximately \$24.5 million.

Our estimated proved reserves and the standardized measure of discounted future net cash flows of the proved reserves at December 31, 2009, 2008, and 2007, 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 2009, we did not have a third party customer that accounted for 10% or more of our oil and natural gas revenues, the top five third party customers accounted for approximately 29% of our oil and natural gas revenues. During 2009, our mid-stream segment purchased \$29.3 million of our natural gas production and natural gas liquids 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 2008 and 2007, we eliminated intercompany revenues of \$56.3 million and \$23.1 million, respectively, of natural gas production and NGLs.

MID-STREAM

General. Superior is a mid-stream company engaged primarily in the buying, selling, gathering, processing and treating of natural gas and operates three natural gas treatment plants, eight operating processing plants, 33 active gathering systems and 839 miles of pipeline. Superior and its subsidiary operate in Oklahoma, Texas, Kansas and Pennsylvania.

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

	Year Ended December 31,		
	2009	2008	2007
Gas gathered—MMBtu/day	183,989	197,367	219,635
Gas processed—MMBtu/day	75,908	67,796	50,350
Natural gas liquids sold—gallons/day	243,492	195,837	129,421

Acquisitions. Our mid-stream segment did not have any significant acquisitions during 2009 or 2008.

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, 2009, 59% of our mid-

stream segment's total volumes and 22% of 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 NGL's it gathers and processes, with the remainder being remitted to the producer. In this arrangement, Superior and the producers are directly dependent on the volume of the commodity and its value; Superior owns a percentage of that commodity and is directly subject to fluctuations in its market value. For the year ended December 31, 2009, 23% of our mid-stream segment's total volumes and 30% 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 NGL's 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 NGL's could be less than the amount paid for the unprocessed natural gas. For the year ended December 31, 2009, 18% of our mid-stream segment's total volumes and 48% of operating margins (as defined below) were under POI contracts.

For 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 2009, ONEOK, Tenaska and ConocoPhillips accounted for approximately 52%, 17% and 15%, respectively, of our mid-stream revenues. We believe that if we lost one or more of these three identified customers, that there are other customers available to purchase our gas and liquids.

VOLATILE NATURE OF OUR BUSINESS

The prevailing prices for natural gas, NGLs and oil significantly affect our revenues, operating results, cash flow and future rate of growth. Because natural gas makes up the biggest part of our oil, NGLs and natural gas reserves, as well as the focus of most of the contract drilling work we do for others, changes in natural gas prices have a larger impact on us than changes in oil and NGL prices. 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 monthly natural gas, oil and NGL prices we received by quarter, for our oil and gas segment, without taking into account the effect of our hedging activity:

Quarter	Natural Gas Price per Mcf		Oil Price per Bbl		NGL Price per Bbl	
	High	Low	High	Low	High	Low
2009:						
Fourth	\$ 4.38	\$ 3.35	\$ 75.11	\$ 71.76	\$ 43.22	\$ 31.12
Third	\$ 3.30	\$ 2.37	\$ 67.62	\$ 60.69	\$ 27.38	\$ 21.38
Second	\$ 2.90	\$ 2.59	\$ 66.48	\$ 39.93	\$ 27.30	\$ 21.34
First	\$ 4.67	\$ 2.45	\$ 42.26	\$ 34.75	\$ 19.95	\$ 17.89
2008:						
Fourth	\$ 4.76	\$ 4.25	\$ 75.09	\$ 39.22	\$ 29.27	\$ 24.36
Third	\$ 11.51	\$ 5.39	\$ 131.75	\$ 102.26	\$ 70.22	\$ 54.14
Second	\$ 10.68	\$ 8.70	\$ 134.81	\$ 109.78	\$ 60.98	\$ 50.82
First	\$ 8.33	\$ 6.59	\$ 102.74	\$ 91.14	\$ 54.43	\$ 45.91
2007:						
Fourth	\$ 6.45	\$ 5.84	\$ 91.96	\$ 83.13	\$ 54.94	\$ 49.48
Third	\$ 6.07	\$ 5.21	\$ 76.09	\$ 69.88	\$ 48.97	\$ 41.32
Second	\$ 7.02	\$ 6.44	\$ 65.23	\$ 60.73	\$ 40.07	\$ 36.92
First	\$ 6.88	\$ 5.80	\$ 58.69	\$ 50.79	\$ 35.41	\$ 31.54

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 to and maintain oil price and production controls;
- demand for oil and natural gas from other developing nations including China and India;
- the price of foreign imports;
- imports of liquefied natural gas;
- actions of governmental authorities;
- the domestic and foreign supply of oil and natural gas;
- the level of consumer demand;
- United States storage levels of natural gas;
- the ability to transport natural gas or oil to key markets;
- weather conditions;
- domestic and foreign government regulations;
- the price, availability and acceptance of alternative fuels;
- the time period associated with the current decrease in commodity prices; and
- overall economic conditions in the United States as well as the world.

These factors and the volatile nature of the energy markets make it impossible to predict 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 2007. This was followed by a resurgence in activity (as well as rates) during the first nine months of 2008, before a decline in activity during the fourth quarter 2008. Dayrates continued to decline throughout 2009 while our drilling rig utilization hit its low in June 2009 before it started to slowly increase during the later part of the year.

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

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. We are the fifth largest U.S. deep onshore drilling contractor.

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 operations compete 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, build gathering systems in production fields and deliver the natural gas 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.

As discussed elsewhere in this report, throughout 2007 and through the first nine months of 2008 all of our operations experienced strong competition for qualified labor. However, due to the depressed conditions within our industry during the end of 2008 and throughout 2009, we do not anticipate that competition to keep and attract qualified drilling employees to meet our immediate future requirements will materially affect us. Likewise, if current commodity price and industry drilling utilization rates continue, we do not anticipate that our contract drilling labor costs will increase from those levels in effect at the end of the fourth quarter of 2009.

OIL AND NATURAL GAS PROGRAMS AND CONFLICTS OF INTEREST

Unit Petroleum Company serves as the general partner of 15 oil and gas limited partnerships. Three of these partnerships were formed for investment by third parties and 12 (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.

The employee partnerships formed in 1984 through 1999 have been consolidated into a single consolidating partnership. The employee partnerships each have a set annual 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 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.

EMPLOYEES

As of February 12, 2010, we had approximately 1,094 employees in our contract drilling operations, 154 employees in our oil and natural gas operations, 75 employees in our mid-stream operations and 93 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 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 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 individual pipeline restructuring proceedings of the early to mid-1990s, the 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 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.

As a result of these changes, 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. 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.

In the past, Congress has been very active in the area of natural gas regulation. However, 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 are not regulated and are at market prices. The price received from the sale of these products will be affected by the cost of transporting the 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 may 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. We are not able to predict with certainty what effect, if any, these relatively new federal regulations or the periodic review of the index by the FERC will have on us.

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

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

Climate Regulation. Recent scientific studies have suggested that emissions of certain gases, commonly referred to as “greenhouse gases”, 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. On December 7, 2009, the EPA responded to the Massachusetts, et al. v. EPA decision and issued a finding that the current and projected concentrations of greenhouse gases in the atmosphere threaten the public health and welfare of current and future generations, and that certain greenhouse gases from new motor vehicles and motor vehicle engines contribute to the atmospheric concentrations of greenhouse gases and hence to the threat of climate change.

In June 2009 the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009 (sometimes referred to as the Waxman-Markey global climate change bill). The bill includes many provisions that would potentially have a significant impact on us as well as our customers. The bill proposes a cap and trade

regime, a renewable portfolio standard, electric efficiency standards, revised transmission policy and mandated investments in plug-in hybrid infrastructure and smart grid technology. Although proposals have been introduced in the U.S. Senate, including a proposal that would require greater reductions in greenhouse gas emissions than the American Clean Energy and Security Act of 2009, it is uncertain at this time whether, and in what form, legislation will be adopted by the U.S. Senate. 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.

On September 22, 2009, EPA finalized a rule requiring nation-wide reporting of greenhouse gas emissions beginning January 1, 2010. The rule applies primarily to large facilities emitting 25,000 metric tons or more of carbon dioxide-equivalent greenhouse gas emissions per year, and to most upstream suppliers of fossil fuels and industrial greenhouse gas, as well as to manufacturers of vehicles and engines.

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 greenhouse gas emissions would impact our business segments. Depending on the final provisions of such rules or legislation, it is possible that such future laws and regulations 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 greenhouse gases, 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

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

Item 1A. Risk Factors

FORWARD-LOOKING STATEMENTS/CAUTIONARY STATEMENT AND RISK FACTORS

This report, including information included in, or incorporated by reference from future filings by us with the SEC, as well as information contained in written material, press releases and oral statements issued by or on our behalf, contain, or may contain, certain statements that are “forward-looking statements” within the meaning of federal securities laws. 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. All statements, other than statements of historical facts, included or incorporated by reference in this report, which address activities, events or developments which we expect or anticipate will or may occur in the future, are forward-looking statements. The words “believes,” “intends,” “expects,” “anticipates,” “projects,” “estimates,” “predicts” and similar expressions are used to identify forward-looking statements.

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 prospects;

- the estimates of our proved oil, NGLs and natural gas reserves;
- oil, NGLs and natural gas reserve potential;
- development and infill drilling potential;
- our drilling prospects;
- expansion and other development trends of the oil and natural gas industry;
- our business strategy;
- production of oil, NGLs and natural gas reserves;
- growth potential for our mid-stream operations;
- 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; and
- our belief that the final outcome of our legal proceedings will not materially affect our financial results.

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

- the risk factors discussed in this report and in the documents we incorporate by reference;
- general economic, market or business conditions;
- the nature or lack of business opportunities that we pursue;
- demand for our land drilling services;
- changes in laws or regulations;
- the time period associated with the current decrease 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 in the future could cause our 2010 consolidated results and beyond to differ materially from those that may be presented in any such forward-looking statement made by or on behalf of us.

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. These factors include the availability of funds to carry out their drilling operations. For many of these parties, even if they have the funds available, their decision to spend those funds is often based on the then current prices for oil, NGLs and natural gas. Many of our customers' budgets tend to be susceptible to the influences of current price fluctuations. Other factors that affect our ability to work our drilling rigs are: the weather which, under adverse circumstances, can delay or even cause the abandonment of a project by an operator; the competition faced by us in securing the award of a drilling contract in a given area; our experience and recognition in a new market area; and the availability of labor to operate our drilling rigs.

As noted elsewhere in this report, the decline in the economy and commodity prices starting in late 2008 significantly reduced the demand for our drilling rigs. If these conditions continue, we expect that the demand for our drilling rigs will continue to be depressed.

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 natural gas and crude oil are heavily dependent on a number of factors beyond our control, including:

- the demand for oil and/or natural gas;
- current weather conditions in the continental United States (which can greatly influence the demand for natural gas at any given time as well as the price we receive for such natural gas);
- the amount and timing of liquid natural gas imports; and
- the ability of current distribution systems in the United States to effectively meet the demand for oil and/or 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 natural gas, NGLs and oil are becoming more and more influenced by trading on the commodities markets which, at times, has tended to increase the volatility associated with these prices resulting, at times, in large differences in such prices even on a week-to-week and month-to-month basis. All of these factors, especially when coupled with the fact that much of our product prices are determined on a daily basis, can, and at times do, lead to wide fluctuations in the prices we receive.

Based on our 2009 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 \$359,000 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 an \$101,000 per month (\$1.2 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 \$123,000 per month (\$1.5 million annualized) change in our pre-tax operating cash flow. During 2009, substantially all of our natural gas, crude oil and NGLs volumes were sold at market responsive prices. To help manage our cash flow and capital expenditure requirements, we hedged approximately 77%, 71% and 33% of our 2009 average daily production for natural gas, crude oil and NGLs, 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. 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 future increases in 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 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. Effective December 31, 2009, as required by the SEC, the estimated discounted future net cash flows from proved oil, NGLs and natural gas reserves are determined based on the unweighted arithmetic average of the price on the first day of the month for each month within the 12-month period before the end of the reporting period, unless prices were defined by contractual arrangements. Previously, the price used was based on the single-day period-end price. 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 and natural gas 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% 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 proved reserves, discounted at 10%. As of December 31, 2009, 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. Previously, 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 \$282.0 million pre-tax (\$175.5 million, net of tax) during the year ended December 31, 2008 as well as 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.

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 facility. 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, 2009, our outstanding long-term debt was \$30.0 million.

Depending on the amount of our debt, the cash flow needed to satisfy our debt and the covenants contained in our bank credit facility, such debt could:

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

We entered into the following interest rate swaps to help manage our exposure to possible future interest rate increases. Under these transactions we have swapped the variable interest rate we would otherwise incur on a portion of our bank debt for a fixed interest rate. Currently, all of our bank debt is subject to the following interest rate swaps. A more thorough discussion of our hedging or swap arrangements is contained in Item 7 of the Management's Discussion and Analysis of Financial Condition and Results of Operation section of this report.

<u>Term</u>	<u>Amount</u>	<u>Fixed Rate</u>	<u>Floating Rate</u>
December 2007 – May 2012	\$ 15,000,000	4.53%	3 month LIBOR
December 2007 – May 2012	\$ 15,000,000	4.16%	3 month LIBOR

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.

Events in the financial markets and the economy could adversely affect our operations and financial condition.

As a result of volatility in oil and natural gas prices and substantial uncertainty in the capital markets due to the uncertain global economic environment, a number of our drilling customers have reduced spending on exploration and development drilling, in addition it is uncertain whether customers and/or vendors and suppliers will be able to access financing necessary to sustain their operations, fulfill their commitments and/or fund future operations and

obligations. The uncertainty in the global economic environment may result in a decrease in demand for drilling rigs. These conditions could have a material adverse effect on our business, financial condition and results of operations.

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

Historically, oil 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 and gas prices. Such factors include, among other things, the domestic and foreign supply of oil 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 lessen in the future. 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 have resulted in a tightening of credit markets in the United States. Liquidity in the global-credit markets has been severely contracted by these market disruptions making terms for certain financings less attractive, and in certain cases, have resulted in the unavailability of certain types of financing. As a result of ongoing 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. Because our oil, NGLs and natural gas reserves are predominantly natural gas, significant changes in natural gas prices would have a particularly large impact on our 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;
- the price of foreign oil imports;
- imports of liquefied natural gas;
- actions of governmental authorities;
- the domestic and foreign supply of oil 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 and natural gas exploration and production industry.

Our contract drilling operations depend on the level of activity in oil 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.

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. On February 12, 2010, our outstanding long-term debt was \$30.0 million. 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 facility, 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 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 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;
- 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;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with governmental requirements;
- delays in the development of other producing properties within the gathering system's area of operation; and
- demand for natural gas and its constituents.

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

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

Our continued 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 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. Effective December 31, 2009, 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. Previously, 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 natural gas, oil 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 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 and gas production to key markets.

The marketability of our oil and natural gas production depends in part on the availability, proximity and capacity of pipeline systems. The unavailability of or lack of 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 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 2009, our largest customer, Questar Corporation accounted for approximately 35% 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.

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.

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 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. *Submission of Matters to a Vote of Security Holders*

No matters were submitted to our security holders during the fourth quarter of 2009.

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:

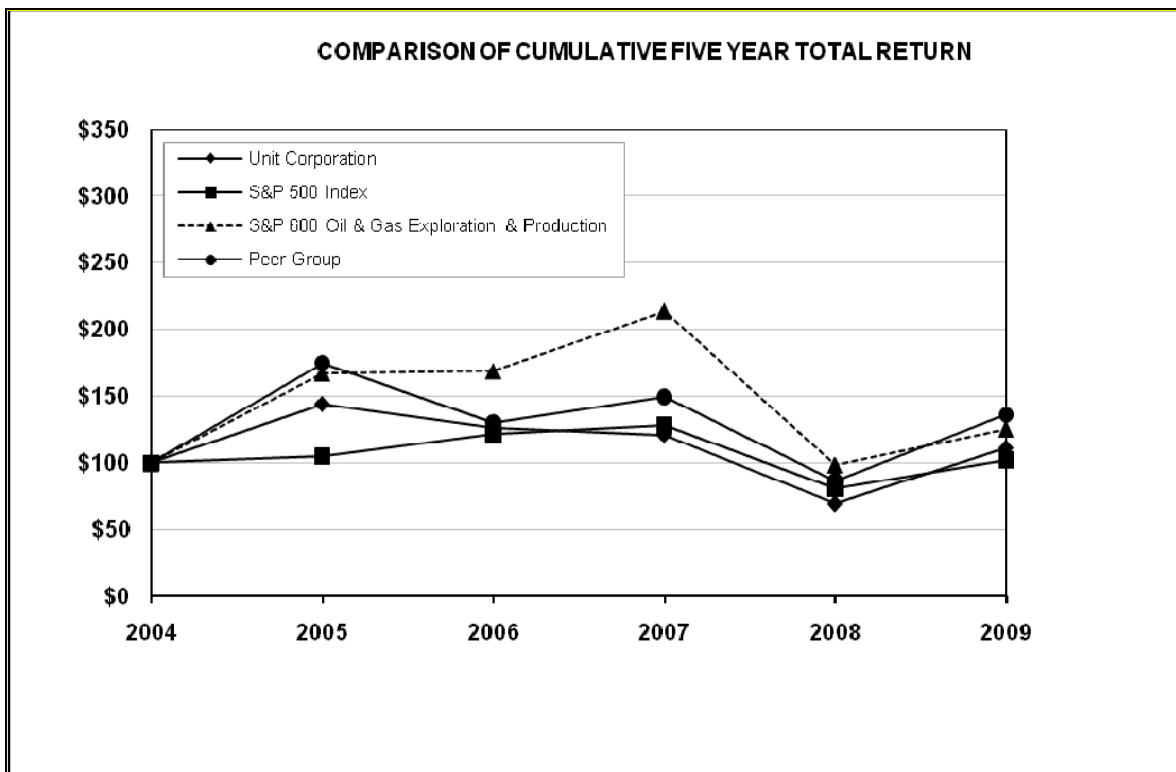
Quarter	2009		2008	
	High	Low	High	Low
First	\$ 31.30	\$ 17.50	\$ 56.95	\$ 44.00
Second	\$ 35.40	\$ 20.16	\$ 84.70	\$ 55.31
Third	\$ 44.15	\$ 24.12	\$ 88.23	\$ 45.20
Fourth	\$ 47.24	\$ 36.24	\$ 49.43	\$ 21.62

On February 12, 2010, the closing sale price of our common stock, as reported by the NYSE, was \$47.03 per share. On that date, there were approximately 1,236 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 facility prohibits the payment of cash dividends on our common stock under certain circumstances. For further information regarding our bank credit facility's impact on our ability to pay dividends see "Our Credit Facility" under Item 7 of this report.

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

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.



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 2009, 2008 and 2007 activity.

	As of and for the Year Ended December 31,				
	2009	2008	2007	2006	2005
	(In thousands except per share amounts)				
Revenues	\$ 709,898	\$ 1,358,093	\$ 1,158,754	\$ 1,162,385	\$ 885,608
Net income (loss)	\$ (55,500) ⁽¹⁾	\$ 143,625 ⁽²⁾	\$ 266,258	\$ 312,177	\$ 212,442
Net income (loss) per common share:					
Basic	\$ (1.18)	\$ 3.08	\$ 5.74	\$ 6.75	\$ 4.62
Diluted	\$ (1.18)	\$ 3.06	\$ 5.71	\$ 6.72	\$ 4.60
Total assets	\$ 2,228,399	\$ 2,581,866	\$ 2,199,819	\$ 1,874,096	\$ 1,456,195
Long-term debt	\$ 30,000	\$ 199,500	\$ 120,600	\$ 174,300	\$ 145,000
Other long-term liabilities	\$ 81,126	\$ 75,807	\$ 59,115	\$ 55,741	\$ 41,981
Cash dividends per common share	\$ —	\$ —	\$ —	\$ —	\$ —

(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 were founded in 1963 as a contract drilling company. Today, we operate, manage and analyze our results of operations through our three principal wholly owned 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 subsidiary. This segment buys, sells, gathers, processes and treats natural gas for third parties and for our own account.

Business Outlook

As discussed in other parts of this report, the success of our consolidated business as well as each of our three main operating segments depends, on a large part, on the prices received for our natural gas, natural gas liquids and oil production and the demand for oil and natural gas as well as for our drilling rigs which, in turn, influences the amounts we can charge for the use of those drilling rigs. While to date all of our 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 impact us and our industry.

In addition to their direct impact on us, lower commodity prices for sustained periods of time could also impact the liquidity of some of our industry partners and customers, which, in turn, might limit their ability to meet their financial obligations to us.

The slowdown in the United States and world economies starting in late 2008 has resulted (to varying degrees) in a reduction in the demand for oil and natural gas products by those industries and consumers that use those products in their business operations. The long-term impact on our business and financial results as a consequence of the volatility in oil and natural gas prices and the global economic downturn is uncertain.

The following table reflects the significant fluctuations in the prices for oil and natural gas:

<u>Date</u>	<u>Gas Spot Price Henry Hub (\$ per MMBtu)</u>	<u>Crude Oil WTI- Cushing, OK (\$ per Bbl)</u>
July 1, 2008	\$ 13.19	\$ 140.99
August 1, 2008	\$ 9.26	\$ 125.10
September 1, 2008	\$ 8.24	\$ 115.48
October 1, 2008	\$ 7.17	\$ 98.55
November 1, 2008	\$ 6.20	\$ 67.81
December 1, 2008	\$ 6.44	\$ 49.28
January 1, 2009	\$ 5.63	\$ 44.61
February 1, 2009	\$ 4.77	\$ 41.70
March 1, 2009	\$ 4.04	\$ 44.76
April 1, 2009	\$ 3.58	\$ 48.39
May 1, 2009	\$ 3.25	\$ 53.20
June 1, 2009	\$ 3.93	\$ 68.58
July 1, 2009	\$ 3.72	\$ 69.31
August 1, 2009	\$ 3.34	\$ 69.45
September 1, 2009	\$ 2.41	\$ 68.05
October 1, 2009	\$ 3.24	\$ 70.82
November 1, 2009	\$ 4.10	\$ 77.00
December 1, 2009	\$ 4.40	\$ 78.37
January 1, 2010	\$ 5.79	\$ 79.36
February 1, 2010	\$ 5.26	\$ 74.43

As noted in the table above, oil and natural gas prices declined significantly after their July 2008 levels before they began to reverse their downward trend by the end of 2009. Our initial 2010 operating budget is based on oil and natural gas prices averaging \$72.00 per Bbl and \$5.30 per Mcf, respectively, for the year. We expect to fund our 2010 operating budget using internally generated cash flow and to a lesser extent from borrowings under our credit facility.

Our 2010 capital budget for all of our business segments forecasts a 60% increase over our 2009 capital expenditures. Our oil and natural gas segment's capital budget is \$365.0 million, a 58% increase over 2009. With the reduction in well costs that occurred during 2009, we are planning an aggressive drilling program in 2010 with a significant portion of the wells being horizontal. Our drilling segment's capital budget is \$76.0 million, a 12% increase over 2009. Our focus will be on refurbishing and upgrading 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 \$53.0 million, a 435% increase over 2009. 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 adding an additional processing facility in the Texas Panhandle to accommodate the increased need resulting from the drilling activity of our oil and natural gas segment.

The impact on our drilling rig utilization and dayrates as a result of this decline in industry exploration and developmental drilling activity and spending during 2009 is reflected in the following table.

<u>Period</u>	<u>Average Rigs in Use</u>	<u>Average Dayrates (1)</u>
July 2008	108.8	\$ 18,276
August 2008	111.2	\$ 18,624
September 2008	112.1	\$ 19,044
October 2008	111.5	\$ 19,229
November 2008	97.8	\$ 19,426
December 2008	81.0	\$ 19,352
January 2009	63.8	\$ 18,993
February 2009	52.2	\$ 18,414
March 2009	42.2	\$ 18,356
April 2009	37.3	\$ 17,749
May 2009	30.2	\$ 17,429
June 2009	27.5	\$ 16,616
July 2009	31.4	\$ 15,460
August 2009	35.3	\$ 15,357
September 2009	37.1	\$ 15,275
October 2009	36.5	\$ 14,942
November 2009	35.9	\$ 14,996
December 2009	37.7	\$ 14,234

(1) As of December 2009, the average dayrates include 26 term contracts, 13 of which all are up for renewal within the next year and the other 13 are up for renewal after 2011.

Executive Summary

Contract Drilling

Our fourth quarter 2009 utilization rate was 28%, compared to 26% and 74% in the third quarter of 2009 and the fourth quarter 2008, respectively. Dayrates for the fourth quarter of 2009 averaged \$14,708, a decrease of 4% from the third quarter of 2009 and 24% from the fourth quarter of 2008. Direct profit (contract drilling revenue less contract drilling operating expense) decreased 14% from the third quarter of 2009 and 77% from the fourth quarter of 2008, primarily due to the decrease in utilization. Operating cost per day increased 2% from the third quarter of 2009 and increased 8% from the fourth quarter of 2008. The decrease from the third quarter 2009 was primarily due to increases in the per day direct cost and general and administrative expenses. The increase from the fourth quarter of 2008 was primarily attributable to certain indirect drilling costs being spread over fewer utilization days partially offset by decreased per day direct cost and decreases in workers' compensation costs. In the third and fourth quarters of 2008, prices for oil and natural gas decreased substantially. While oil prices tended to increase during 2009, natural gas prices remained depressed through most of 2009, before they began to increase during the fourth quarter

of 2009. With anticipated increases to 2010 drilling activity and spending by our customers we may see an increase in our 2010 drilling rig utilization as compared to levels at the end of 2009.

During 2009, we sold three mechanical drilling rigs and acquired one new 1,500 horsepower diesel electric drilling rig for \$13.2 million. These transactions brought our total fleet to 130 drilling rigs at December 31, 2009.

Our anticipated 2010 capital expenditures for this segment are \$76.0 million.

We agreed to delay the delivery of a new 1,500 horsepower diesel electric drilling rig that was to have been delivered to North Dakota under a long term contract in the first quarter of 2009. Under that agreement, our customer agreed to make monthly payments pending the future delivery of the rig. Our customer has now advised us to prepare the rig for mobilization to North Dakota for use in their drilling program during the first quarter of 2010.

In January and February 2010, our contract drilling segment entered into contracts to sell eight of its idle mechanical drilling rigs to an unaffiliated third party. These drilling rigs ranged in horse power from 800 to 1,000. The closing on three of these drilling rigs occurred in February. Three more are scheduled to close during the first quarter of 2010 with the last transaction for the remaining two rigs anticipated to close during the second quarter of 2010. Proceeds from the sale of all the drilling rigs will be \$23.9 million resulting in an estimated gain of \$6.1 million. The proceeds from this sale will be used to refurbish and upgrade additional rigs in our fleet in order that those rigs can 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. At completion of the sale of the eight rigs and with the additional rig recently placed into service, this segment will have 123 drilling rigs in its fleet.

Oil and Natural Gas

Fourth quarter 2009 production from our oil and natural gas segment was 156,000 Mcfe per day, a 2% decrease over the third quarter of 2009 and a 15% decrease over the fourth quarter of 2008. The decreases are primarily due to a significant reduction in the number of wells drilled during the year and the fourth quarter of 2008 and to a lesser extent the curtailment and shut-in of third-party plants of approximately 1.2 Bcfe of production during 2009.

Oil and natural gas revenues increased 2% from the third quarter of 2009 and decreased 16% from the fourth quarter of 2008. Our oil, natural gas and NGL prices in the fourth quarter of 2009, increased 3%, 2% and 13%, respectively, from the third quarter of 2009 and our oil and NGL prices decreased 21% and 1%, respectively, from the fourth quarter of 2008 while natural gas prices increased 4%. Direct profit (oil and natural gas revenues less oil and natural gas operating expense) decreased 4% from the third quarter of 2009 and decreased 19% from the fourth quarter of 2008. The decrease from the third quarter 2009 was primarily attributable to an increase in production taxes and the fourth quarter 2008 primarily resulted from a decrease in production and oil prices. Operating cost per Mcfe produced increased 23% from the third quarter of 2009 and increased 13% from the fourth quarter of 2008. We hedged 71% of our 2009 average daily oil production, approximately 77% of our 2009 average natural gas production and approximately 33% of our 2009 average NGL production to help manage our cash flow and capital expenditure requirements. Currently for 2010, we have hedged 71% of our average daily oil production (based on our 2009 production) and approximately 69% of our average daily natural gas production (based on our 2009 production).

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 the end of the first quarter. At December 31, 2009, the 12-month average of commodity prices, including the discounted value of our commodity hedges, were at levels that did not require us to record a year-end write-down of our oil and natural gas properties. Previously, 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. Should the 12-month average for commodity prices decline below that existing at year-end, including the discounted value of our commodity hedges, an additional write-down of the carrying value of our oil and natural gas properties could be required in future periods.

Our estimated production for 2010 is approximately 66.0 to 67.0 Bcfe, an increase of 9% to 10% from our 2009 production. We currently anticipate that we will participate in the drilling of approximately 175 wells during 2010, an increase of 84% over 2009. Our anticipated 2010 capital expenditures for this segment are \$365.0 million.

In the third and fourth quarter of 2008, commodity prices decreased substantially and remained at low levels through the third quarter of 2009. As a result of these lower commodity prices and the relatively high costs for well drilling services, we decided to reduce our drilling activity during the fourth quarter of 2008 and continued to do so through the second quarter of 2009. We began increasing activity during the third quarter of 2009 and plan to continue to increase activity throughout 2010.

Mid-Stream

Fourth quarter 2009 liquids sold per day increased 5% from the third quarter of 2009 and increased 34% from the fourth quarter of 2008. Liquids sold per day increased from the third quarter of 2009 primarily due to operating the processing plants in an ethane rejection mode during the third quarter of 2009 due to an extremely low ethane price, and increased from the fourth quarter of 2008 primarily as the result of upgrades and expansions to existing plants. Gas processed per day was essentially unchanged from the third quarter of 2009 and increased 7% over the fourth quarter of 2008. In 2008, we upgraded several of our existing processing facilities and added three processing plants which was the primary reason for increased volumes. Gas gathered per day decreased 1% from the third quarter of 2009 and 6% from the fourth quarter of 2008 primarily from our Southeast Oklahoma gathering system experiencing natural production declines associated with connected wells.

NGL prices in the fourth quarter of 2009 increased 41% from the price received in the third quarter of 2009 and 9% over the price received in the fourth quarter of 2008. The price of liquids 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. We currently do not have any fractionation spread hedges in place for 2010 and beyond.

Direct profit (mid-stream revenues less mid-stream operating expense) increased 45% from the third quarter of 2009 and increased 138% from the fourth quarter of 2008. The increase from the third quarter 2009 and the fourth quarter 2008 resulted primarily from increased commodity prices and to a lesser extent an increase in volumes. Total operating cost for our mid-stream segment increased 40% from the third quarter of 2009 and increased 13% from the fourth quarter of 2008 due primarily to the increase in the price paid for the purchase of natural gas. Our anticipated capital expenditures for 2010 for this segment are \$53.0 million. For 2010, we anticipate an increase in well connections due to anticipated drilling activity by operators in the areas of our existing gathering systems as well as adding an additional processing facility to accommodate the increased drilling activity of our oil and natural gas segment.

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.

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.

<u>Accounting Policies</u>	<u>Estimates or Assumptions</u>	<u>Accounts Affected</u>
Full cost method of accounting for oil, NGLs and natural gas properties	<ul style="list-style-type: none"> • 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 	<ul style="list-style-type: none"> • 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	<ul style="list-style-type: none"> • Cost estimates related to the plugging and abandonment of wells • Timing of cost incurred 	<ul style="list-style-type: none"> • 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	<ul style="list-style-type: none"> • Forecast of undiscounted estimated future net operating cash flows 	<ul style="list-style-type: none"> • Drilling and mid-stream property and equipment • Accumulated depletion, depreciation and amortization • Provision for depletion, depreciation and amortization • Other intangible assets
Goodwill	<ul style="list-style-type: none"> • Forecast of discounted estimated future net operating cash flows • Terminal value • Weighted average cost of capital 	<ul style="list-style-type: none"> • Goodwill • Provision for depletion, depreciation and amortization
Turnkey and footage drilling contracts	<ul style="list-style-type: none"> • Estimates of costs to complete turnkey and footage contracts 	<ul style="list-style-type: none"> • Revenue and operating expense • Current assets and liabilities
Accounting for value of stock compensation awards	<ul style="list-style-type: none"> • Estimates of stock volatility • Estimates of expected life of awards granted • Estimates of rates of forfeitures 	<ul style="list-style-type: none"> • Oil and natural gas properties • Shareholder's equity • Operating expenses • General and administrative expenses
Accounting for derivative instruments and hedging	<ul style="list-style-type: none"> • Derivatives measured at fair value • Derivatives measured for effectiveness and ineffectiveness • Non-qualifying derivatives measured at fair value 	<ul style="list-style-type: none"> • Current and non-current assets and liabilities • Other comprehensive income as a component of equity • Oil and natural gas revenue

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 very 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 85% of the total proved discounted future net cash flows based on the unescalated pricing policy of the SEC as taken from reserve and income projections prepared by us as of December 31, 2009. 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:

<u>Type of Reserves</u>	<u>Nature of Available Data</u>	<u>Degree of Accuracy</u>
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. Effective December 31, 2009, SEC requirements require that the pricing we use be the unweighted arithmetic average of the price on the first day of the month for each month within the 12-month period before the end of the reporting period, unless prices were defined by contractual arrangements. Previously, 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. The transition to the new rule in 2009 resulted in significantly lower prices being used in year-end reporting as compared to what would have been used had the single-day year-end prices still been in effect. The prices used in our reserve estimates were \$3.86 per Mcf for natural gas, \$61.18 per Bbl for oil, and \$34.44 per Bbl for NGLs, as opposed to \$5.79 per Mcf for natural gas, \$79.36 per Bbl for oil and \$55.13 per Bbl for NGLs, which would have been the prices under the old SEC rules. Our reserves under the new rules are 25 bcfe lower than what they would have been under the old rules.

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:

- $DD\&A\ Rate = \frac{Unamortized\ Cost}{Beginning\ of\ Period\ Reserves}$
- $Provision\ for\ DD\&A = DD\&A\ Rate \times Current\ Period\ Production$

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 2009 production level of 60,709,000 equivalent Mcf, a 5% decline in the amount of our 2009 oil, NGLs and natural gas reserves would increase our DD&A rate by \$0.09 per Mcfe and would decrease pre-tax income by \$5.5 million annually. A 5% increase in the amount of our 2009 oil, NGLs and natural gas reserves would decrease our DD&A rate by \$0.08 per Mcfe and would increase pre-tax income by \$4.9 million annually.

Our DD&A expense on our oil and natural gas properties is calculated each quarter utilizing period end reserve quantities. The new SEC oil and gas reserves measurement and disclosure rules that went into effect as of December 31, 2009 impacted our DD&A expense for the fourth quarter of 2009, increasing DD&A expense by \$1.2 million (or \$0.02 per share) for the quarter and year ended December 31, 2009.

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 (effective December 31, 2009) on our oil, NGLs and natural gas adjusted for any cash flow hedges, plus the lower of cost or estimated fair value of unproved properties not 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 2009 average unescalated prices of \$61.18 per barrel of oil, \$34.44 per barrel of NGLs and \$3.86 per Mcf of natural gas, for the estimated life of the respective properties, the unamortized cost of our oil and natural gas properties did not exceed the ceiling of our proved oil, NGL and natural gas reserves. Previously, 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. Oil, NGLs and natural gas prices remain volatile and any significant declines below prices used in the reserve evaluation could result in a ceiling test write-down in the future.

Derivative instruments qualifying as cash flow hedges are to be included in the computation of limitation on capitalized costs. Our qualifying cash flow hedges as of December 31, 2009, which consisted of swaps and collars, covered 36.5 Bcfe in 2010. The effect of these cash flow hedges was a \$88.5 million pre-tax increase in the value of our oil and natural gas properties. 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 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, 2009, 2008 or 2007.

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, 2009, 2008 or 2007.

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 2009, we drilled one well under a footage contract and in 2008, we did not drill any wells under turnkey or footage contracts.

Mid-Stream Contracts. We recognize revenue from the gathering and processing of natural gas and NGLs in the period the service is provided based on contractual terms.

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 possible future interest rate increases and the variability in cash flows associated with the forecasted sale of our future natural gas, NGLs and oil production. We have hedged a portion of our anticipated oil and natural gas production for the next 12 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.

New Accounting Standards

The FASB Accounting Standards Codification. FASB Accounting Standards Codification (ASC) became effective during the third quarter of 2009. ASC 105, *Generally Accepted Accounting Principles*, (guidance formerly reflected in FAS168) established the ASC as the single source of authoritative U.S. generally accepted accounting principles (U.S. GAAP) recognized by the FASB to be applied by nongovernmental entities. Rules and interpretive

releases of the SEC under authority of federal securities laws are also sources of authoritative U.S. GAAP for SEC registrants. The ASC supersedes all existing non-SEC accounting and reporting standards. All other nongrandfathered non-SEC accounting literature not included in the ASC will become nonauthoritative. Following ASC 105, the FASB will not issue new standards in the form of Statements, FASB Staff Positions, or Emerging Issues Task Force Abstracts. Instead, the FASB will issue Accounting Standards Updates, which will serve only to: (a) update the ASC; (b) provide background information about the guidance; and (c) provide the basis for conclusions on the change(s) in the ASC. The adoption of this standard has changed how we reference various elements of U.S. GAAP in our financial statement disclosures, but has no impact on our financial position, results of operation or cash flows.

Fair Value Measurements and Disclosures. Beginning in 2008, we adopted the effective provisions of ASC 820 *Fair-Value Measurements* (formerly FAS 157.) ASC 820 defines fair value in applying GAAP, establishes a framework for measuring fair value and expands disclosures about fair-value measurements. ASC 820 does not change existing guidance as to whether or not an instrument is carried at fair value.

In February 2008, the FASB delayed the effective date of ASC 820 for one year for certain nonfinancial assets and nonfinancial liabilities, except those recognized or disclosed at fair value in the financial statements on a recurring basis. On January 1, 2009, we adopted, the delayed provisions of ASC 820 related to nonfinancial assets and nonfinancial liabilities that are not required or permitted to be measured at fair value on a recurring basis. The adoption of the delayed provisions did not have a material impact on our financial statements.

Modernization of Oil and Gas Reporting. On December 31, 2008, the Securities and Exchange Commission (SEC) adopted major revisions to its rules governing oil and gas company reporting requirements. These include provisions that permit the use of new technologies to determine proved reserves, and that allow companies to disclose their probable and possible reserves to investors. The current rules limit disclosure to only proved reserves. The new rules also require companies to report the independence and qualifications of the auditor of the reserve estimates and file reports when a third party is relied on to prepare reserves estimates. The new rules also require that oil and gas reserves be reported and the full cost ceiling value calculated using an average price based on the first-of-month posted price for each month in the prior 12-month period. On January 5, 2010, the FASB issued Accounting Standards update (ASU) 2010-03 - *Extractive Activities - Oil and Gas (ASC 932): Oil and Gas Reserve Estimation and Disclosures*, an update of ASC 932 *Extractive Activities - Oil and Gas*, which subsequently aligns the reserve estimation, disclosure requirements, and definitions of ASC 932 with the disclosure requirements of the new rules issued by the SEC. The new oil and gas reserve measurement and reporting requirements were adopted for oil and gas reserves as of December 31, 2009. For accounting purposes, the new requirements constitute a change in accounting principle inseparable from a change in estimate. As such, prior reserve disclosures were not modified and the impact of the new requirements on our oil and gas reserves was reflected as a change in estimate. As previously noted, reserves and discounted cash flows prepared using the new rules were used in the calculation of DD&A for the fourth quarter of 2009 and the ceiling test at December 31, 2009.

Interim Disclosures about Fair Value of Financial Instruments. On June 30, 2009, we implemented certain provisions of ASC 825, *Financial Instruments*, (guidance formerly reflected in FASB Staff Position (FSP) Statement No. 107-1 and Accounting Principles Board (APB) 28-1, *Interim Disclosures about Fair Value of Financial Instruments*). The new provisions require disclosures about fair value of financial instruments in interim financial information. We are required to disclose in the body or in the accompanying notes of our summarized financial information for interim reporting periods and in our financial statements for annual reporting periods, the fair value of all financial instruments for which it is practicable to estimate that value, whether recognized or not recognized in the statement of financial position. We have included the required disclosure in Note 6 of our Notes to Consolidated Financial Statements.

Subsequent Events. On June 30, 2009, we implemented certain provisions of ASC 855, *Subsequent Events*, (guidance formerly reflected in FAS165, *Subsequent Events*). The new provision establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. ASC 855 provides:

- The period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements;

- The circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and
- The disclosures that an entity should make about events or transactions that occurred after the balance sheet date.

We have included the required disclosure in Note 2 of our Notes to Consolidated Financial Statements.

Consolidations of Variable Interest Entities. On June 12, 2009, the FASB issued ASU 2009-17 - *Consolidations (ASC 810): Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities*, the FASB amended the authoritative guidance on consolidation which requires an enterprise to perform an analysis to determine whether the enterprise's variable interest or interests give it a controlling financial interest in a variable interest entity. In order to be the primary beneficiary of a variable interest entity, an enterprise must have (a) the power to direct the activities of a variable interest entity that most significantly impact the entity's economic performance, and (b) the obligation to absorb losses of the entity that could potentially be significant to the variable interest entity or the right to receive benefits from the entity that could potentially be significant to the variable interest entity. Along with these criteria, an enterprise is now required to assess whether it has an implicit financial responsibility to ensure that a variable interest entity operates as designed when determining (a) above. Also, the enterprise is required to perform ongoing reassessments of whether an enterprise is the primary beneficiary of a variable interest entity. The quantitative approach previously required for determining the primary beneficiary has been eliminated. Additional disclosures are now required in order to provide users of financial statements with more transparent information about an enterprise's involvement in a variable interest entity. This amendment is effective for the first fiscal year beginning after November 15, 2009. This ASU does not currently have a material impact on us.

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 is the first interim or annual reporting period beginning after December 15, 2009, except for the gross presentation of the Level 3 roll forward information, which is required for annual reporting periods beginning after December 15, 2010 and for interim reporting periods within those years. This statement will not have a significant impact on us due to it only requiring enhanced disclosures.

Financial Condition and Liquidity

Summary. Our financial condition and liquidity depends on the cash flow from our operations and borrowings under our Credit Facility. Our cash flow is influenced mainly by:

- 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 natural gas production and, to a lesser extent, the prices we receive for our oil 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:

	<u>2009</u>	<u>2008</u>	<u>2007</u>
	(In thousands except percentages)		
Working capital	\$ 22,948	\$ 90,186	\$ 40,611
Long-term debt	\$ 30,000	\$ 199,500	\$ 120,600
Shareholders' equity ⁽¹⁾	\$ 1,565,810	\$ 1,633,099	\$ 1,434,817
Ratio of long-term debt to total capitalization ⁽¹⁾	2 %	11 %	8 %
Net income (loss) ⁽¹⁾	\$ (55,500)	\$ 143,625	\$ 266,258
Net cash provided by operating activities	\$ 490,475	\$ 689,913	\$ 577,571
Net cash used in investing activities	\$ (271,927)	\$ (806,141)	\$ (512,333)
Net cash provided by (used in) financing activities	\$ (217,992)	\$ 115,736	\$ (64,751)

(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 Facility. 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. The write down impacted our 2008 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 Facility.

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

	<u>2009</u>	<u>2008</u>	<u>2007</u>
Contract Drilling:			
Average number of our drilling rigs in use during the period	38.9	103.1	99.4
Total number of drilling rigs owned at the end of the period	130	132	129
Average dayrate	\$ 16,713	\$ 18,458	\$ 18,663
Oil and Natural Gas:			
Oil production (MMbbls)	1,286	1,261	1,091
Natural gas liquids production (MMbbls)	1,488	1,388	785
Natural gas production (MMcft)	44,063	47,473	43,464
Average oil price per barrel received	\$ 56.33	\$ 93.87	\$ 70.61
Average oil price per barrel received excluding hedges	\$ 56.64	\$ 98.02	\$ 70.61
Average NGL price per barrel received	\$ 22.81	\$ 47.42	\$ 45.03
Average NGL price per barrel received excluding hedges	\$ 25.66	\$ 47.38	\$ 45.01
Average natural gas price per mcf received	\$ 5.59	\$ 7.62	\$ 6.30
Average natural gas price per mcf received excluding hedges	\$ 3.26	\$ 7.53	\$ 6.24
Mid-Stream:			
Gas gathered—MMBtu/day	183,989	197,367	219,635
Gas processed—MMBtu/day	75,908	67,796	50,350
Gas liquids sold — gallons/day	243,492	195,837	129,421
Number of natural gas gathering systems	33	37	36
Number of processing plants	8	9	8

At December 31, 2009, we had unrestricted cash of \$1.1 million and we had borrowed \$30.0 million of the \$325.0 million available under our Credit Facility. Our Credit Facility is primarily used for working capital, capital expenditures and acquisitions. Prior to 2009, most of our capital expenditures are discretionary and directed toward future growth. Beginning in the fourth quarter of 2008 and continuing through 2009, we significantly reduced our level of capital expenditures due to the uncertain economic environment. For 2010, we plan to increase our level of capital expenditures, again being focused on growth and funded mainly through internally generated cash flow and to a lesser extent from borrowings under the credit facility.

Working Capital. Typically, our working capital balance fluctuates primarily because of the timing of our accounts receivable and accounts payable. We had working capital of \$22.9 million, \$90.2 million and \$40.6

million as of December 31, 2009, 2008 and 2007, respectively. The effect of our derivatives increased working capital by \$4.7 million, \$32.4 million and \$1.3 million as of December 31, 2009, 2008 and 2007, respectively.

Contract Drilling. Our contract drilling work is subject to many factors that influence the number of drilling rigs we have working as well as the costs and revenues associated with that work. These factors include the demand for drilling rigs, competition from other drilling contractors, the prevailing prices for natural gas and oil, availability and cost of labor to run our drilling rigs and our ability to supply the equipment needed.

If the current depressed conditions within our industry continue, we do not anticipate that competition to keep and attract qualified employees to meet our immediate and future requirements will materially affect us. Likewise, if current commodity price and industry drilling utilization rates continue, we do not anticipate that our contract drilling labor costs will increase from those levels in effect at the end of the fourth quarter of 2009.

Most of our drilling rig fleet is used to drill natural gas wells so changes in natural gas prices have a disproportionate influence on the demand for our drilling rigs as well as the prices we can charge for our contract drilling services. In 2009, our average dayrate was \$16,713 per day compared to \$18,458 per day in 2008 and \$18,663 per day in 2007. The average number of our drilling rigs used in 2009 was 38.9 drilling rigs (30%) compared with 103.1 drilling rigs (79%) in 2008 and 99.4 drilling rigs (80%) for 2007. Based on the average utilization of our drilling rigs during 2009, a \$100 per day change in dayrates has a \$3,890 per day (\$1.4 million annualized) change in our pre-tax operating cash flow. Industry demand for our drilling rigs remained strong during the second and third quarters of 2008 before the fourth quarter downturn. We expect that utilization and dayrates for our drilling rigs will slowly improve for 2010 compared to 2009 and depend mainly on the price of natural gas, the levels of natural gas storage and the availability of drilling rigs to meet the demands of the industry.

Our contract drilling subsidiaries provide drilling services for our exploration and production subsidiary. The contracts for these services contain the same terms and rates as the contracts we use with unrelated third parties for comparable type projects. During 2009, 2008 and 2007, we drilled 38, 122 and 77 wells, respectively, for our exploration and production subsidiary. The profit associated with these wells received by our contract drilling segment of \$1.3 million, \$27.9 million and \$22.7 million during 2009, 2008 and 2007, respectively, was used to reduce the carrying value of our oil and natural gas properties rather than being included in our operating profit.

Impact of Prices for Our Oil, NGLs and Natural Gas. Natural gas comprises approximately 73% of our oil, NGLs and natural gas reserves. Any significant change in natural gas prices has a material effect on our revenues, cash flow and the value of our oil, liquids 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 2009, 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 \$359,000 per month (\$4.3 million annualized) change in our pre-tax operating cash flow. Our 2009 average natural gas price was \$5.59 compared to an average natural gas price of \$7.62 for 2008 and \$6.30 for 2007. A \$1.00 per barrel change in our oil price, without the effect of hedging, would have an \$101,000 per month (\$1.2 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 \$123,000 per month (\$1.5 million annualized) change in our pre-tax operating cash flow based on our production in 2009. Our 2009 average oil price per barrel was \$56.33 compared with an average oil price of \$93.87 in 2008 and \$70.61 in 2007 and our 2009 average NGL price per barrel was \$22.81 compared with an average liquids price of \$47.42 in 2008 and \$45.03 in 2007.

Because natural gas prices have such a significant 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 bank credit facility since that determination is based mainly on the value of our oil, NGLs and natural gas reserves. Such a reduction could limit our ability to carry out our planned capital projects.

Most of our natural gas production is sold to third parties under month-to-month contracts.

Mid-Stream Operations. Our mid-stream operations are conducted through Superior Pipeline Company, L.L.C. and its subsidiary. Superior is a mid-stream company engaged primarily in the buying, selling, gathering, processing and treating of natural gas and operates three natural gas treatment plants, eight processing plants, 33 gathering systems and 839 miles of pipeline. Superior operates in Oklahoma, Texas, Kansas and Pennsylvania and has been in business since 1996. 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 2009, 2008 and 2007 this segment purchased \$29.3 million, \$52.0 million and \$18.4 million, respectively, of our natural gas production and natural gas liquids and provided gathering and transportation services of \$4.6 million, \$4.3 million and \$4.7 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 183,989 MMBtu per day in 2009 compared to 197,367 MMBtu per day in 2008 and 219,635 MMBtu per day in 2007, processed an average of 75,908 MMBtu per day in 2009 compared to 67,796 MMBtu per day in 2008 and 50,350 MMBtu per day in 2007 and sold NGLs of 243,492 gallons per day in 2009 compared to 195,837 gallons per day in 2008 and 129,421 gallons per day in 2007. The average gas gathering volumes per day in 2009 decreased 7% compared to 2008 primarily due to a decline in our Southeast Oklahoma gathering system due to natural production declines associated with the connected wells and decreased new well connections. Volumes processed increased due to the increase in NGL volumes sold.

Our Credit Facility. On December 23, 2008, we entered into a First Amendment to our existing First Amended and Restated Senior Credit Agreement (Credit Facility) with a maximum credit amount of \$400.0 million maturing on May 24, 2012. This amendment increased the lenders' commitment by \$50.0 million to an aggregate of \$325.0 million. Borrowings under the Credit Facility are limited to a commitment amount elected by us. As of December 31, 2009, the commitment amount was \$325.0 million. We are charged a commitment fee of 0.375 to 0.50 of 1% on the amount available but not borrowed with the rate varying based on the amount borrowed as a percentage of the total borrowing base amount. We incurred origination, agency and syndication fees of \$737,500 at the inception of the Credit Facility and \$478,125 associated with the December 23, 2008 First Amendment. These fees are being amortized over the life of the agreement. The average interest rate for 2009 was 4.0%. At both December 31, 2009 and February 12, 2010, borrowings were \$30.0 million.

The lenders under our Credit Facility and their respective participation interests are as follows:

<u>Lender</u>	<u>Participation Interest</u>
Bank of Oklahoma, N.A.	18.75%
Bank of America, N.A.	18.75%
BMO Capital Markets Financing, Inc.	18.75%
Compass Bank	17.50%
Comerica Bank	08.75%
Fortis Capital Corp.	08.75%
Calyon New York Branch	08.75%
	<u>100.00%</u>

The lenders' aggregate commitment is limited to the lesser of the amount of the value of the borrowing base or \$400.0 million. The amount of the borrowing base, which is subject to redetermination on April 1 and October 1 of each year, is based primarily on a percentage of the discounted future value of our oil, NGLs and natural gas reserves, as determined by the lenders, and, to a lesser extent, the loan value the lenders reasonably attribute to the cash flow (as defined in the Credit Facility) of our mid-stream operations. The current borrowing base is \$475.0 million. We or the lenders may request a onetime special redetermination of the borrowing base amount between each scheduled redetermination. In addition, we may request a redetermination following the consummation of an acquisition meeting the requirements defined in the Credit Facility.

At our election, any part of the outstanding debt under the Credit Facility may be fixed at LIBOR for a 30, 60, 90 or 180 day term. During any LIBOR funding period, the outstanding principal balance of the promissory note to which the LIBOR option applies may be repaid on three days prior notice to the administrative agent and on our

payment of any applicable funding indemnification amounts. Interest on the LIBOR is computed at the LIBOR base applicable for the interest period 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 the LIBOR bear interest at the BOKF National Prime Rate, which in no event will be less than LIBOR plus 1.00%, and is payable at the end of each month. Any amount borrowed not subject to LIBOR may be repaid at any time, in part or in whole, without premium or penalty. At December 31, 2009, all of our outstanding borrowings of \$30.0 million were subject to LIBOR.

The Credit Facility prohibits:

- the payment of dividends (other than stock dividends) during any fiscal year in excess of 25% of our consolidated net income for the preceding fiscal year;
- the incurrence of additional debt with certain very 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 Facility also requires that we have at the end of each quarter:

- a consolidated net worth of at least \$900.0 million;
- a current ratio (as defined in the Credit Facility) of not less than 1 to 1; and
- a leverage ratio of long-term debt to consolidated EBITDA (as defined in the Credit Facility) for the most recently ended rolling four fiscal quarters of no greater than 3.50 to 1.0.

As of December 31, 2009, we were in compliance with the covenants contained in the Credit Facility.

We entered into the following interest rate swaps to help manage our exposure to possible future interest rate increases. Under these transactions we have swapped the variable interest rate we would otherwise incur on a portion of our bank debt for a fixed interest rate.

<u>Term</u>	<u>Amount</u>	<u>Fixed Rate</u>	<u>Floating Rate</u>
December 2007 – May 2012	\$ 15,000,000	4.53%	3 month LIBOR
December 2007 – May 2012	\$ 15,000,000	4.16%	3 month LIBOR

Capital Requirements

Drilling Acquisitions and Capital Expenditures. During 2006, we purchased major components to be used in the construction of two new 1,500 horsepower drilling rigs. The first was placed into service in our Rocky Mountain division at the end of March 2007 and the second was placed into service in the second quarter of 2007. The combined capitalized cost of both drilling rigs was \$19.4 million. On June 5, 2007, we completed the acquisition of a privately owned drilling company operating primarily in the Texas Panhandle. The acquired company owned nine drilling rigs, a fleet of 11 trucks, and an office, shop and equipment yard. The drilling rigs range from 800 horsepower to 1,000 horsepower with depth capacities rated from 10,000 to 15,000 feet. Eight of the nine drilling rigs were operating under contracts on the acquisition date. The remaining drilling rig was refurbished and placed in service during the first quarter of 2008. Results of operations for the acquired company have been included in our statements of income beginning June 5, 2007. Total consideration paid for this acquisition was \$38.5 million.

For our contract drilling operations, during 2007, we recorded \$220.4 million in capital expenditures including the effect of a \$19.4 million deferred tax liability and \$5.3 million in goodwill associated with our second quarter 2007 acquisition.

For 2008, our capital expenditures for this segment were \$196.2 million. During the second quarter of 2008, we completed the construction of two new 1,500 horsepower diesel electric drilling rigs for approximately \$32.2 million and placed these drilling rigs into service in our Rocky Mountain division. During the fourth quarter of 2008, we completed the construction of another new 1,500 horsepower diesel electric drilling rig for approximately \$14.1 million and placed that drilling rig into service in North Dakota.

In late 2008, we postponed the construction of eight additional drilling rigs we had previously anticipated building. 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 these eight rigs. 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.

We agreed to delay the delivery of a new 1,500 horsepower diesel electric drilling rig that was to have been delivered to North Dakota under a long term contract in the first quarter of 2009. Under that agreement, our customer agreed to make monthly payments pending the future delivery of the rig. Our customer has now advised us to prepare the rig for mobilization to North Dakota for use in their drilling program during the first quarter of 2010.

We currently do not have a shortage of drill pipe and drilling equipment. At December 31, 2009, we had commitments to purchase approximately \$0.8 million of drilling rig components and \$18.0 million of drill pipe and drill collars in 2010. For 2009, our capital expenditures were \$67.7 million. Our anticipated 2010 capital expenditures for this segment are \$76.0 million.

In January and February 2010, our contract drilling segment entered into contracts to sell eight of its idle mechanical drilling rigs to an unaffiliated third party. These drilling rigs ranged in horse power from 800 to 1,000. The closing on three of these drilling rigs occurred in February. Three more are scheduled to close during the first quarter of 2010 with the last transaction for the remaining two rigs anticipated to close during the second quarter of 2010. Proceeds from the sale of all the drilling rigs will be \$23.9 million resulting in an estimated gain of \$6.1 million. The proceeds from this sale will be used to refurbish and upgrade additional rigs in our fleet in order that those rigs can 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. At completion of the sale of the eight rigs and with the additional rig recently placed into service, this segment will have 123 drilling rigs in its fleet.

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 95 gross wells (42.51 net wells) in 2009 compared to 278 gross wells (134.31 net wells) in 2008 and 253 gross wells (96.64 net wells) in 2007. Our 2009 total capital expenditures for our oil and natural gas segment, excluding a \$4.6 million ARO liability, totaled \$226.0 million. Currently we plan to participate in drilling approximately 175 gross wells in 2010 and estimate our total capital expenditures (excluding any possible acquisitions) for our oil and natural gas segment will be approximately \$365.0 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, 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.

On January 18, 2008, we purchased a 50% interest in a 6,800 gross-acre leasehold that we did not already own in our Segno area of operations located in Hardin County, Texas. Included in the purchase were five producing wells with 4.9 Bcfe of estimated proved reserves and current production of 2.8 MMcf of natural gas per day and 88.2 barrels of condensate. The purchase price was \$16.8 million which consisted of \$15.8 million allocated to the reserves of the wells and \$1.0 million allocated to the undeveloped leasehold.

In September 2008, we completed an acquisition consisting of a 75% working interest in four producing wells and other proved undeveloped properties for \$22.2 million along with working interests in undeveloped leasehold valued at approximately \$3.5 million, all located in the Texas Panhandle region.

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.

As of December 31, 2009, we had commitments to purchase casing for \$0.5 million.

Mid-Stream Acquisitions and Capital Expenditures. As of December 31, 2008, we had commitments to purchase two new processing plants. After December 31, 2008, we cancelled the purchase of one of these plants due to nonperformance of contractual terms. We are seeking to recover the \$2.8 million progress payments made toward the full purchase price before this contract was terminated. In March 2009, we cancelled our remaining commitment for the second plant and incurred a \$1.3 million penalty.

During 2009, our mid-stream segment incurred \$9.9 million in capital expenditures as compared to \$49.9 million in 2008 and \$34.2 million in 2007, including acquisitions. For 2010, we have budgeted capital expenditures of approximately \$53.0 million. The increase over 2009 expenditures is due to anticipated drilling activity by operators in the areas of our existing gathering systems resulting in new well connections as well as adding an additional processing facility to accommodate the increased drilling activity of our oil and natural gas segment.

Contractual Commitments. At December 31, 2009, we had the following contractual obligations:

	Payments Due by Period				
	Total	Less Than 1 Year	2-3 Years (In thousands)	4-5 Years	After 5 Years
Bank debt (1)	\$ 33,123	\$ 1,304	\$ 31,819	\$ —	\$ —
Operating leases (2)	1,123	594	500	29	—
Drill pipe, drilling components and equipment purchases (3)	19,345	19,345	—	—	—
Total contractual obligations	\$ 53,591	\$ 21,243	\$ 32,319	\$ 29	\$ —

- (1) See previous discussion in MD&A regarding our bank credit facility. This obligation is presented in accordance with the terms of the credit facility and includes interest calculated using our year end interest rate of 4.3% which includes the effect of the interest rate swaps.
- (2) We lease office space or yards in Tulsa, Oklahoma; Houston and Canadian, Texas; Englewood and Denver, Colorado; Pinedale, Wyoming; and Pittsburgh, Pennsylvania under the terms of operating leases expiring through May, 2012. 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 \$18.8 million of new drilling rig components, drill pipe, drill collars and related equipment and \$0.5 million of casing over the next twelve months.

After December 31, 2009, we amended the lease for our office space in Tulsa, Oklahoma. Subject to all the terms of the lease, the amendment extended the lease from January 2010 to January 2015 for an approximate commitment of \$6.0 million. Also, subsequent to December 31, 2009, we entered into an agreement to purchase a 50mmcf/d gas plant for approximately \$6.2 million which is to be paid in 2010.

At December 31, 2009, we also had the following commitments and contingencies that could create, increase or accelerate our liabilities:

Other Commitments	Estimated Amount of Commitment Expiration Per Period				
	Total Accrued	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
	(In thousands)				
Deferred compensation plan (1)	\$ 2,004	Unknown	Unknown	Unknown	Unknown
Separation benefit plans (2)	\$ 4,681	\$ 354	Unknown	Unknown	Unknown
Derivative liabilities – interest rate swaps	\$ 1,948	\$ 806	\$ 1,142	\$ —	\$ —
Derivative liabilities – commodity hedges	\$ 1,424	\$ 1,424	\$ —	\$ —	\$ —
ARO liability (3)	\$ 56,404	\$ 1,080	\$ 16,888	\$ 4,456	\$ 33,980
Gas balancing liability (4)	\$ 3,263	Unknown	Unknown	Unknown	Unknown
Repurchase obligations (5)	\$ —	Unknown	Unknown	Unknown	Unknown
Workers' compensation liability (6)	\$ 22,974	\$ 7,908	\$ 3,238	\$ 1,235	\$ 10,593

- (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 Sheet, 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 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 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 we have recorded 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 2010, 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. Such repurchases in any one year are limited to 20% of the units outstanding. We made repurchases of \$1,000 and \$241,000 in 2009 and 2008, respectively, and did not have any repurchases in 2007.
- (6) We have recorded a liability for future estimated payments related to workers’ compensation claims primarily

associated with our contract drilling segment.

Derivative Activities. As of January 1, 2009, we applied the provisions of ASC 815, *Derivatives and Hedging*, (guidance formerly reflected in FAS161, *Disclosures about Derivative Instruments and Hedging Activities*). The new provision requires enhanced disclosures about a company's derivative activities and how the related hedged items affect a company's financial position, financial performance and cash flows. These enhanced disclosures are discussed in Note 13 of our Notes to Consolidated Financial Statements.

Periodically we enter into hedge transactions covering part of the interest we incur under our Credit Facility as well as the prices to be received for a portion of our future oil, NGLs and natural gas production.

Interest Rate Swaps. From time to time we have entered into interest rate swaps to help manage our exposure to possible future interest rate increases under our Credit Facility. As of December 31, 2009, we had two outstanding interest rate swaps which were cash flow hedges. Under these transactions we have swapped the variable interest rate we would otherwise incur on a portion of our bank debt for a fixed interest rate. There was no material amount of ineffectiveness. Our December 31, 2009 balance sheet recognized the fair value of these swaps as current and non-current derivative liabilities and is presented in the table below:

Term	Amount	Fixed Rate	Floating Rate	Fair Value Asset (Liability)
	(\$ in thousands)			
December 2007 – May 2012	\$ 15,000	4.53%	3 month LIBOR	\$ (1,041)
December 2007 – May 2012	\$ 15,000	4.16%	3 month LIBOR	(907)
				<u>\$ (1,948)</u>

Because of these interest rate swaps, interest expense increased by \$1.0 million and \$0.3 million in 2009 and 2008, respectively. A loss of \$1.2 million, net of tax, is reflected in accumulated other comprehensive income (loss) as of December 31, 2009.

Commodity Derivatives. We use hedging to reduce price volatility and manage price risks. Our decision on the quantity and price at which we choose to hedge certain of our production is based, in part, on our view of current and future market conditions. Based on our 2009 average daily production, as of February 12, 2010, the approximated percentages we have hedged are as follows:

Oil and Natural Gas Segment:

	<u>January – December 2010</u>	<u>January – December 2011⁽¹⁾</u>
Daily oil production	71%	— %
Daily natural gas production	69%	— %

(1) Currently for 2011, we only have basis differential swaps covering 30,000 MMBtu/day.

With respect to the commodities subject to the hedge, the use of hedging limits the risk of adverse downward price movements, but it also limits increases in future revenues that would otherwise result from favorable price movements.

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 valuation at December 31, 2009 and determined it was immaterial at that time. At February 12, 2010, Bank of Montreal, Bank of America, N.A., Calyon New York Branch, Comerica Bank and Compass Bank were the counterparties with respect to all of our commodity derivative transactions. At December 31, 2009, the fair values of the net assets (liabilities) we had with each of these counterparties was \$1.5 million, \$6.3 million, \$1.0 million, \$1.1 million and (\$1.4) million, respectively.

To the extent that a legal right of set-off exists, we net the value of our derivative arrangements with the same counterparty in the accompanying consolidated balance sheets. At December 31, 2009, we recorded the fair value of our commodity derivatives on our balance sheet as current derivative assets of \$9.9 million and current derivative liabilities of \$1.4 million. At December 31, 2008, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current derivative assets of \$52.1 million and \$5.2 million, respectively, and current derivative liabilities of \$0.7 million.

We recognize the effective portion of changes in fair value as accumulated other comprehensive income (loss), 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, 2009, we had a gain of \$5.7 million, net of tax from our oil and natural gas segment derivatives and no gain or loss from our mid-stream segment derivatives in accumulated other comprehensive income (loss).

Based on market prices at December 31, 2009, we expect to transfer approximately \$4.7 million, net of tax, of the \$5.7 million, net of tax, gain included in the balance in accumulated other comprehensive income (loss) to earnings during the next 12 months in the related month of production. The interest rate swaps and commodity derivative instruments as of December 31, 2009 are expected to mature by May 2012 and December 31, 2010, respectively.

Certain derivatives do not qualify for designation as cash flow hedges. We had two basis swaps that did not qualify as cash flow hedges that expired in December 2009. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of income as unrealized gains (losses) within oil and natural gas revenues. Changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized into earnings. Any change in fair value resulting from ineffectiveness is recognized currently in oil and natural gas revenues as unrealized gains (losses). The effect of these realized and unrealized gains and losses on our revenues and expenses were as follows at December 31:

	<u>2009</u>	<u>2008</u>	<u>2007</u>
	(In thousands)		
Increases (decreases) in:			
Oil and natural gas revenue:			
Realized gains (losses) on oil and natural gas derivatives	\$ 97,864	\$ (1,010)	\$ 2,589
Unrealized gains (losses) on ineffectiveness of cash flow hedges	(897)	255	—
Unrealized gains (losses) on non-qualifying oil and natural gas derivatives	<u>(1,047)</u>	<u>1,047</u>	<u>—</u>
Total increase on oil and natural gas revenues due to derivatives	95,920	292	2,589
Gas gathering and processing revenue (all realized gains (losses))	—	2,022	(2,078)
Gas gathering and processing expense (all realized losses)	<u>—</u>	<u>1,438</u>	<u>1,694</u>
Impact on pre-tax earnings	<u>\$ 95,920</u>	<u>\$ 876</u>	<u>\$ (1,183)</u>

Stock and Incentive Compensation. During 2009, we did not grant any awards of restricted stock. During 2008, we granted awards covering 30,855 shares of restricted stock. These awards were granted as retention incentive awards. During 2007, we granted awards covering 616,907 shares of restricted stock. These awards included specific one time retention awards as well as awards which were part of our annual compensation determinations. Also in 2007, we granted awards covering 101,236 shares of stock appreciation rights to certain of our executive officers. No SAR awards were made during 2008 or 2009. During 2009, we recognized compensation expense of \$9.2 million for all of our restricted stock, stock options and SAR grants and capitalized \$2.1 million of compensation cost for oil and natural gas properties. Compensation expense for the 2007 and 2008 grants has been recognized over the three year vesting periods.

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 for fiduciary liability to \$1.0 million for drilling rig physical damage. 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.

Oil and Natural Gas Limited Partnerships and Other Entity Relationships. We are the general partner of 15 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 2009, 2008 and 2007, the total we received for all of these fees was \$1.1 million, \$1.9 million and \$1.6 million, respectively. We expect that these fees for 2010 will be comparable to those in 2009. 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 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. Before 1999, the effect of inflation on our operations was minimal due to low inflation rates, relatively low natural gas and oil prices and moderate demand for our contract drilling services. Over the last several years natural gas 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.

Results of Operations

2009 versus 2008

Following is a comparison of selected operating and financial data:

	<u>2009</u>	<u>2008</u>	<u>Percent Change</u>
Total revenue	\$ 709,898,000	\$ 1,358,093,000	(48)%
Net income (loss)	\$ (55,500,000)	\$ 143,625,000	(139)%
Contract Drilling:			
Revenue	\$ 236,315,000	\$ 622,727,000	(62)%
Operating costs excluding depreciation	\$ 140,080,000	\$ 312,907,000	(55)%
Percentage of revenue from daywork contracts	100%	100%	—%
Average number of drilling rigs in use	38.9	103.1	(62)%
Average dayrate on daywork contracts	\$ 16,713	\$ 18,458	(9)%
Depreciation	\$ 45,326,000	\$ 69,841,000	(35)%
Oil and Natural Gas:			
Revenue	\$ 357,879,000	\$ 553,998,000	(35)%
Operating costs excluding depreciation, depletion, amortization and impairment	\$ 87,734,000	\$ 116,239,000	(25)%
Average oil price (Bbl)	\$ 56.33	\$ 93.87	(40)%
Average NGL price (Bbl)	\$ 22.81	\$ 47.42	(52)%
Average natural gas price (Mcf)	\$ 5.59	\$ 7.62	(27)%
Oil production (Bbl)	1,286,000	1,261,000	2%
NGL production (Bbl)	1,488,000	1,388,000	7%
Natural gas production (Mcf)	44,063,000	47,473,000	(7)%
Depreciation, depletion and amortization rate (Mcfe)	\$ 1.87	\$ 2.50	(25)%
Depreciation, depletion and amortization	\$ 114,681,000	\$ 159,550,000	(28)%
Impairment of oil and natural gas properties	\$ 281,241,000	\$ 281,966,000	—%
Mid-Stream Operations:			
Revenue	\$ 108,628,000	\$ 181,730,000	(40)%
Operating costs excluding depreciation and amortization	\$ 87,908,000	\$ 150,466,000	(42)%
Depreciation and amortization	\$ 16,104,000	\$ 14,822,000	9%
Gas gathered—MMBtu/day	183,989	197,367	(7)%
Gas processed—MMBtu/day	75,908	67,796	12%
Gas liquids sold—gallons/day	243,492	195,837	24%
General and administrative expense	\$ 24,011,000	\$ 25,419,000	(6)%
Interest expense, net	\$ 539,000	\$ 1,304,000	(59)%
Income tax expense (benefit)	\$ (32,226,000)	\$ 81,954,000	(139)%
Average interest rate	4.0%	4.5%	(11)%
Average long-term debt outstanding	\$ 111,808,000	\$ 149,315,000	(25)%

Contract Drilling:

Drilling revenues decreased \$386.4 million or 62% in 2009 versus 2008 primarily due to a 62% decrease in the average number of rigs in use during 2009 compared to 2008. The decline in revenue was partially offset by \$6.1 million of revenue recognized during the third and fourth quarters of 2009 from settlements of terminated drilling contracts. Average drilling rig utilization decreased from 103.1 drilling rigs in 2008 to 38.9 drilling rigs in 2009. Our average dayrate in 2009 was 9% lower than in 2008. In the third and fourth quarters of 2008, prices for oil and natural gas decreased substantially and natural gas prices continued to be at low levels during 2009 and may remain volatile for an indeterminable period of time. Entering the third quarter of 2009, the decline in utilization started to

moderate and improved slightly through the end of 2009, but weak natural gas prices could impact the demand for drilling rigs which may keep utilization rates at low levels. However, with anticipated increases to 2010 drilling activity and spending, we may see an increase on our 2010 drilling rig utilization as compared to levels at the end of 2009.

Drilling operating costs decreased \$172.8 million or 55% between the comparative years of 2009 and 2008 primarily due to the decrease in the number of drilling rigs used. The utilization decreases experienced in the industry since the third quarter of 2008 has reduced the demand for rig personnel which has reduced the pressure on our labor costs. Likewise, that pressure on our other daily direct drilling costs resulted in little change of those costs as well, but reduced utilization has resulted in fewer rigs to cover our indirect fixed costs. As demand for our rigs begins to increase so will the competition for qualified labor. Contract drilling depreciation decreased \$24.5 million or 35%, we utilize the units of production method for the depreciation of our drilling rigs, therefore in periods of reduced utilization a decrease in depreciation occurs.

Oil and Natural Gas:

Oil and natural gas revenues decreased \$196.1 million or 35% in 2009 as compared to 2008 primarily due to a decrease in average oil, NGL and natural gas prices. Average oil prices between the comparative years decreased 40% to \$56.33 per barrel, NGL prices decreased 52% to \$22.81 per barrel and natural gas prices decreased 27% to \$5.59 per Mcf. In 2009, as compared to 2008, oil production increased 2%, NGL production increased 7% and natural gas production decreased 7%. During 2009 approximately 1.2 Bcf of natural gas production was curtailed due to low commodity prices and the shut-in of third party plants. A large part of our increase in revenues during 2008 was determined by the prices we received for our production. Commodity prices decreased substantially during the third and fourth quarters of 2008 and natural gas prices stayed at low levels during 2009 and may remain volatile for an indeterminable period of time. As a result of these lower commodity prices as well as service costs that remained relatively high, we slowed our drilling activity during the fourth quarter of 2008 and continued to do so through the second quarter of 2009. We began increasing activity during the third quarter of 2009 and currently plan to continue to increase our activity throughout 2010.

Oil and natural gas operating costs decreased \$28.5 million or 25% between the comparative years of 2009 and 2008 primarily due to reduced production taxes associated with the large decrease in commodity prices and \$5.1 million in production tax credits attributable to high-cost gas wells. Also contributing to the decrease was a reduction in general and administrative expenses as compensation costs were reduced in response to the downturn in the industry.

Total depreciation, depletion and amortization (DD&A), excluding ceiling test impairments, decreased \$44.9 million or 28% primarily due to a 25% decrease in our DD&A and lower production volumes. The decrease in our DD&A rate in 2009 compared to 2008 resulted primarily from the \$282.0 million and \$281.2 million pre-tax non-cash ceiling test write-down of the carrying value of our oil and natural gas properties in the fourth quarter of 2008 and the first quarter 2009, respectively, as a result of a decline in commodity prices. Our DD&A expense on our oil and natural gas properties is calculated each quarter utilizing period end reserve quantities. The new SEC oil and gas reserves measurement and disclosure rules that went into effect as of December 31, 2009 impacted our DD&A expense for the fourth quarter of 2009, increasing DD&A expense by \$1.2 million (or \$0.02 per share) for the quarter and year ended December 31, 2009.

Mid-Stream:

Our mid-stream revenues were \$73.1 million or 40% lower for 2009 as compared to 2008 primarily due to lower NGL and natural gas prices slightly offset by higher NGL volumes processed and sold. The average price for NGLs sold decreased 45% and the average price for natural gas sold decreased 55%. Gas processing volumes per day increased 12% between the comparative periods and NGLs sold per day increased 24% 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 2008 and 2009. 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 decreased 7% primarily from well production declines associated with the wells gathered from one of our gathering systems located in Southeast Oklahoma. NGL sales increased by \$2.0 million in 2008 due to the impact of NGL hedges. There were no NGL hedges in place for 2009.

Operating costs decreased \$62.6 million or 42% in 2009 compared to 2008 primarily due to a 52% decrease in prices paid for natural gas purchased and an 8% decrease in field operating expense. Depreciation and amortization increased \$1.3 million, or 9%, primarily attributable to the additional depreciation associated with capital expenditures between the comparative periods. Operating costs increased by \$1.4 million in 2008 due to the impact of natural gas purchase hedges; however there were no hedges in place during 2009. For 2010, we anticipate an increase in well connections over 2009 due to anticipated drilling activity by operators in the areas of our existing gathering systems as well as adding an additional processing facility to accommodate the increased drilling activity of our oil and natural gas segment.

Other:

Other revenue of \$7.1 million for the year ended 2009 was primarily attributable to the sale of three mechanical drilling rigs during the year.

General and administrative expense decreased \$1.4 million or 6% in 2009 compared to 2008. This decrease was primarily attributable to decreased payroll expenses due to efforts to manage cost in this economic environment.

Interest expense, net of capitalized interest, decreased \$0.8 million or 59% between the comparative periods of 2009 and 2008. Capitalized interest reduced our interest expense by \$5.1 million in 2009 versus \$6.0 million in 2008. We capitalized interest based on the net book value associated with our undeveloped oil and natural gas properties, the construction of additional drilling rigs and the construction of gas gathering systems. Our average interest rate was 11% lower and our average debt outstanding was 25% lower in 2009 as compared to 2008. Interest expense was increased \$1.0 million for 2009 and \$0.3 million for 2008 from interest rate swap settlements.

Income tax expense (benefit) changed from an expense of \$82.0 million in 2008 to a benefit of \$32.2 million in 2009 due to declines in income from lower commodity prices and reduced rig utilization and dayrates. Our effective tax rate was 36.7% and 37.0% for 2009 and 2008, respectively with the effect of the deferred tax benefit related to the ceiling test write-down of our oil and natural gas properties. The portion of our taxes reflected as a current income tax benefit for 2009 was \$0.2 million or 0.7% of the total income tax benefit for 2009 as compared with \$40.9 million or 50% of total income tax expense in 2008. The decrease in the percentage of tax expense (benefit) and the reduction in tax expense recognized as current were both the result of lower taxable income. Income taxes paid in 2009 were \$12.3 million.

2008 versus 2007

Following is a comparison of selected operating and financial data:

	<u>2008</u>	<u>2007</u>	<u>Percent Change</u>
Total revenue	\$ 1,358,093,000	\$ 1,158,754,000	17 %
Net income	\$ 143,625,000	\$ 266,258,000	(46) %
Contract Drilling:			
Revenue	\$ 622,727,000	\$ 627,642,000	(1) %
Operating costs excluding depreciation	\$ 312,907,000	\$ 304,780,000	3 %
Percentage of revenue from daywork contracts	100 %	100 %	— %
Average number of drilling rigs in use	103.1	99.4	4 %
Average dayrate on daywork contracts	\$ 18,458	\$ 18,663	(1) %
Depreciation	\$ 69,841,000	\$ 56,804,000	23 %
Oil and Natural Gas:			
Revenue	\$ 553,998,000	\$ 391,480,000	42 %
Operating costs excluding depreciation, depletion, amortization and impairment	\$ 116,239,000	\$ 97,109,000	20 %
Average oil price (Bbl)	\$ 93.87	\$ 70.61	33 %
Average NGL price (Bbl)	\$ 47.42	\$ 45.03	5 %
Average natural gas price (Mcf)	\$ 7.62	\$ 6.30	21 %
Oil production (Bbl)	1,261,000	1,091,000	16 %
NGL production (Bbl)	1,388,000	785,000	77 %
Natural gas production (Mcf)	47,473,000	43,464,000	9 %
Depreciation, depletion and amortization rate (Mcfe)	\$ 2.50	\$ 2.32	8 %
Depreciation, depletion and amortization	\$ 159,550,000	\$ 127,417,000	25 %
Impairment of oil and natural gas properties	\$ 281,966,000	\$ —	100 %
Mid-Stream Operations:			
Revenue	\$ 181,730,000	\$ 138,595,000	31 %
Operating costs excluding depreciation and amortization	\$ 150,466,000	\$ 119,776,000	26 %
Depreciation and amortization	\$ 14,822,000	\$ 11,059,000	34 %
Gas gathered—MMBtu/day	197,367	219,635	(10) %
Gas processed—MMBtu/day	67,796	50,350	35 %
Gas liquids sold—gallons/day	195,837	129,421	51 %
General and administrative expense	\$ 25,419,000	\$ 22,036,000	15 %
Interest expense, net	\$ 1,304,000	\$ 6,362,000	(80) %
Income tax expense	\$ 81,954,000	\$ 147,153,000	(44) %
Average interest rate	4.5 %	6.0 %	(25) %
Average long-term debt outstanding	\$ 149,315,000	\$ 170,141,000	(12) %

Contract Drilling:

Drilling revenues decreased \$4.9 million or 1% in 2008 versus 2007 primarily due to our average dayrate in 2008 decreasing by 1% compared to 2007. Although the average number of drilling rigs operating in 2008 increased over 2007, the significant decline in prices for oil and natural gas beginning in the third quarter of 2008 and continuing throughout the fourth quarter of 2008 resulted in a significant decrease in our utilization. The average number of drilling rigs operating during the third quarter of 2008 was 110.7, however by December of 2008, the average number of drilling rigs operating had declined to 81.0.

Drilling operating costs increased \$8.1 million or 3% between the comparative years of 2008 and 2007 primarily due to the increase in the number of drilling rigs used. Our labor costs increased late in the third quarter of

2008, due to adjustments to rig crew personnel compensation. Contract drilling depreciation increased \$13.0 million or 23% as the total number of drilling rigs owned increased between the comparative periods.

Oil and Natural Gas:

Oil and natural gas revenues increased \$162.5 million or 42% in 2008 as compared to 2007 due to an increase in average oil, NGL and natural gas prices and a 16% increase in equivalent production volumes. Average oil prices between the comparative years increased 33% to \$93.87 per barrel, NGL prices increased 5% to \$47.42 per barrel and natural gas prices increased 21% to \$7.62 per Mcf. In 2008, as compared to 2007, oil production increased 16%, NGL production increased 77% and natural gas production increased 9%. Increased production came primarily from our ongoing internal development drilling activity. A large part of our increase in revenues during 2008 was determined by the prices we received for our production. Commodity prices started to decrease during the third quarter of 2008 and continued to decrease throughout the fourth quarter of 2008. As a result of lower commodity prices combined with service costs that remain relatively high, we slowed down our drilling activity during the fourth quarter of 2008.

Oil and natural gas operating costs increased \$19.1 million or 20% between the comparative years of 2008 and 2007. An increase in the average cost per equivalent Mcf produced represented 15% of the increase in operating costs with the remaining 85% of the increase attributable to the increase in volumes produced from wells added from our developmental drilling. Increases in general and administrative expenses directly related to oil and natural gas production and gross production taxes from higher revenues contributed to the majority of the operating cost increase. General and administrative expenses increased as labor costs increased primarily due to a 22% increase in the average number of employees working in the exploration and production area while lease operating expenses increased primarily due to an increase in the number of wells producing and also from increases in the cost of goods purchased and third-party services. Gross production taxes increased primarily as a result of the increase in oil and natural gas revenues.

DD&A increased \$32.1 million or 25%. Higher production volumes accounted for 64% of the increase while increases in our DD&A rate represented 36% of the increase. The increase in our DD&A rate in 2008 compared to 2007 resulted primarily from increases in the cost of oil and natural gas reserves added in 2007 and 2008 due to higher drilling and completion costs.

We recorded a non-cash ceiling test write down of \$282.0 million pre-tax (\$175.5 million, net of tax) during the year ended December 31, 2008 as a result of declines in commodity prices. After December 31, 2008 commodity prices have continued to decrease.

Mid-Stream:

Our mid-stream revenues were \$43.1 million or 31% higher for 2008 as compared to 2007 due to the higher NGL volumes processed and sold combined with higher NGL and natural gas prices. The average price for NGLs sold increased 15% and the average price for natural gas sold increased 17%. Gas processing volumes per day increased 35% between the comparative years and NGLs sold per day increased 51% between the comparative years. A 10% decrease in gathering volumes per day partially offset the increase in revenue from natural gas liquids and processing sales. The significant increase in volumes processed per day is primarily attributable to the installation of three processing plants in 2007 and, to a lesser extent, volumes added from new wells connected to existing systems throughout 2007 and 2008. NGLs sold volumes per day increased due to recent upgrades to several of our processing facilities. Gas gathering volumes decreased primarily from well production declines associated with the wells gathered from one of our gathering systems located in Southeast Oklahoma. NGL sales increased by \$2.0 million in 2008 compared to being reduced by \$2.1 million in 2007 due to the impact of NGL hedges.

Operating costs increased \$30.7 million or 26% in 2008 compared to 2007 due to a 25% increase in natural gas volumes purchased per day and a 18% increase in prices paid for natural gas purchased, a 25% increase in field direct operating expense due to the additions to our natural gas gathering and processing systems and the volume of natural gas processed and an 72% increase in general and administrative expenses associated with our mid-stream segment. The total number of employees working in our mid-stream segment increased by 44%. Depreciation and amortization increased \$3.8 million, or 34%, primarily attributable to the additional depreciation associated with

assets acquired between the comparative periods. Operating costs increased by \$1.4 million in 2008 compared to \$1.7 million in 2007 due to the impact of natural gas purchase hedges. Commodity prices started to decline in the third quarter of 2008 and continued to decrease throughout the fourth quarter of 2008.

Other:

General and administrative expense increased \$3.4 million or 15% in 2008 compared to 2007. This increase was primarily attributable to increased stock based compensation costs and increased payroll expenses due to an 8% increase in the number of employees.

Total interest expense, net of capitalized interest, decreased \$5.1 million or 80% between the comparative years. Our average debt outstanding and our average interest rate were 12% and 25% lower, respectively, in 2008 as compared to 2007. We capitalized interest based on the net book value associated with our undeveloped inventory of oil and natural gas properties, the construction of additional drilling rigs and the construction of gas gathering systems. Capitalized interest reduced our interest expense by an additional \$1.5 million in 2008 versus 2007 and represented 29% of the \$5.1 million decrease in interest expense. Interest expense was increased \$0.3 million for 2008 and was reduced \$0.7 million for 2007 from interest rate swap settlements.

Income tax expense decreased \$65.2 million or 44% due primarily to the decrease in income before income taxes associated with the write down of our oil and natural gas properties creating an income tax benefit of \$106.4 million. Our effective tax rate was 37% and 36% for 2008 and 2007, respectively before the effect of the deferred tax benefit related to the ceiling test write-down of our oil and natural gas properties. The portion of our taxes reflected as current income tax expense for 2008 was \$40.9 million or 50% of total income tax expense for 2008 as compared with \$66.6 million or 45% of total income tax expense in 2007. The increase in the percentage of tax expense recognized as current is the result of the deferred income tax benefit recognized in 2008 in association with the write down of our oil and natural gas properties. Income taxes paid in 2008 were \$45.7 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 2009 production, a \$0.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding \$359,000 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 an \$101,000 per month (\$1.2 million annualized) change in our pre-tax operating cash flow and a \$1.00 per barrel change in our NGLs prices would have a \$123,000 per month (\$1.5 million annualized) change in our pre-tax cash flow.

We use hedging transactions to reduce price volatility and manage price risks. 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, and collars that set a floor and ceiling price for the hedged production. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, we will settle the difference with the counterparty to the collars. Currently, we also have one basis swap that does not qualify as cash flow hedge. These financial derivatives are intended to support oil and gas prices at targeted levels and to manage our exposure to oil and gas price fluctuations. We do not hold or issue derivative instruments for speculative trading purposes.

Oil and Natural Gas Segment:

At December 31, 2009, we had the following outstanding cash flow hedges:

<u>Term</u>	<u>Commodity</u>	<u>Hedged Volume</u>	<u>Weighted Average Fixed Price for Swaps</u>	<u>Hedged Market</u>
Jan'10 – Dec'10	Crude oil - collar	1,000 Bbl/day	\$67.50 put & \$81.53 call	WTI – NYMEX
Jan'10 – Dec'10	Crude oil – swap	1,500 Bbl/day	\$61.36	WTI – NYMEX
Jan'10 – Dec'10	Natural gas – swap	15,000 MMBtu/day	\$ 7.20	IF – NYMEX (HH)
Jan'10 – Dec'10	Natural gas – swap	20,000 MMBtu/day	\$ 6.89	IF – Tenn Zone 0
Jan'10 – Dec'10	Natural gas – swap	30,000 MMBtu/day	\$ 6.12	IF – CEGT
Jan'10 – Dec'10	Natural gas – swap	20,000 MMBtu/day	\$ 5.67	IF – PEPL
Jan'10 – Dec'10	Natural gas – basis differential swap	10,000 MMBtu/day	(\$0.79)	PEPL – NYMEX

Subsequent to December 31, 2009, we had the following outstanding non-qualifying cash flow derivatives:

<u>Term</u>	<u>Commodity</u>	<u>Hedged Volume</u>	<u>Basis Differential</u>	<u>Hedged Market</u>
Jan'11 – Dec'11	Natural gas – basis differential swap	30,000 MMBtu/day	(\$0.14)	TennZ0 – NYMEX

Interest Rate Risk. Our interest rate exposure relates to our long-term debt under our Credit Facility. That debt, at our election bears interest at variable rates based on the BOKF National Prime Rate or the LIBOR Rate. At our election, borrowings under our Credit Facility may be fixed at the LIBOR Rate for periods of up to 180 days. To help manage our exposure to any future interest rate volatility, we currently have two \$15.0 million interest rate swaps, one at a fixed rate of 4.53% and one at a fixed rate of 4.16%, both expiring in May 2012. Under these transactions we have swapped the variable interest rate we would otherwise incur on a portion of our bank debt for a fixed interest rate. Based on our average outstanding long-term debt subject to a variable rate in 2009, a 1% increase in the floating rate would reduce our annual pre-tax cash flow by approximately \$0.8 million.

Item 8. *Financial Statements and Supplementary Data*

**Index to Financial Statements
Unit Corporation and Subsidiaries**

	<u>Page</u>
Management's Report on Internal Control over Financial Reporting	63
Consolidated Financial Statements:	
Report of Independent Registered Public Accounting Firm	64
Consolidated Balance Sheets at December 31, 2009 and 2008	65
Consolidated Statements of Operations for the Years Ended December 31, 2009, 2008 and 2007	66
Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2007, 2008 and 2009	67
Consolidated Statements of Cash Flows for the Years Ended December 31, 2009, 2008 and 2007	68
Notes to Consolidated Financial Statements	69

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, 2009. 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, 2009, 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, 2009, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

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, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, 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, 2009, 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, 2010

**UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS**

	As of December 31,	
	2009	2008
	(In thousands except share and par value amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 1,140	\$ 584
Restricted cash	20	20
Accounts receivable (less allowance for doubtful accounts of \$5,186 and \$4,893)	74,382	192,408
Materials and supplies	6,914	9,923
Current derivative asset (Note 13)	9,945	52,177
Current income tax receivable	15,236	11,768
Current deferred tax asset (Note 8)	14,423	12,467
Prepaid expenses and other	6,035	7,238
Total current assets	128,095	286,585
Property and equipment:		
Drilling equipment	1,217,361	1,172,655
Oil and natural gas properties, on the full cost method:		
Proved properties	2,309,193	2,090,623
Undeveloped leasehold not being amortized	140,129	160,034
Gas gathering and processing equipment	172,549	169,402
Transportation equipment	30,726	33,611
Other	22,747	22,484
	3,892,705	3,648,809
Less accumulated depreciation, depletion, amortization and impairment	1,879,112	1,447,157
Net property and equipment	2,013,593	2,201,652
Goodwill (Note 2)	62,808	62,808
Other intangible assets, net	5,633	9,384
Non-current derivative asset (Note 13)	—	5,218
Other assets	18,270	16,219
Total assets	\$ 2,228,399	\$ 2,581,866
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	\$ 55,880	\$ 129,755
Accrued liabilities (Note 5)	34,571	51,659
Contract advances	3,124	2,889
Current portion of derivative liabilities (Note 13)	2,230	1,481
Current portion of other long-term liabilities (Note 6)	9,342	10,615
Total current liabilities	105,147	196,399
Long-term debt (Note 6)	30,000	199,500
Long-term derivative liabilities (Note 13)	1,142	1,780
Other long-term liabilities (Note 6)	79,984	74,027
Deferred income taxes (Note 8)	446,316	477,061
Commitments and contingencies (Note 15)		
Shareholders' equity:		
Preferred stock, \$1.00 par value, 5,000,000 shares authorized, none issued	—	—
Common stock, \$0.20 par value, 175,000,000 shares authorized, 47,530,669 and 47,255,964 shares issued as of December 31, 2009 and 2008, respectively	9,405	9,325
Capital in excess of par value	383,957	367,000
Accumulated other comprehensive income (net of tax of \$2,757 and \$19,548, respectively)	4,458	33,284
Retained earnings	1,167,990	1,223,490
Total shareholders' equity	1,565,810	1,633,099
Total liabilities and shareholders' equity	\$ 2,228,399	\$ 2,581,866

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2009	2008	2007
	(In thousands except per share amounts)		
Revenues:			
Contract drilling	\$ 236,315	\$ 622,727	\$ 627,642
Oil and natural gas	357,879	553,998	391,480
Gas gathering and processing	108,628	181,730	138,595
Other	7,076	(362)	1,037
Total revenues	709,898	1,358,093	1,158,754
Expenses:			
Contract drilling:			
Operating costs	140,080	312,907	304,780
Depreciation	45,326	69,841	56,804
Oil and natural gas:			
Operating costs	87,734	116,239	97,109
Depreciation, depletion and amortization	114,681	159,550	127,417
Impairment of oil and natural gas properties (Note 2)	281,241	281,966	—
Gas gathering and processing:			
Operating costs	87,908	150,466	119,776
Depreciation and amortization	16,104	14,822	11,059
General and administrative	24,011	25,419	22,036
Interest, net	539	1,304	6,362
Total expenses	797,624	1,132,514	745,343
Income (loss) before income taxes	(87,726)	225,579	413,411
Income tax expense (benefit):			
Current	(223)	40,877	66,642
Deferred	(32,003)	41,077	80,511
Total income taxes	(32,226)	81,954	147,153
Net income (loss)	\$ (55,500)	\$ 143,625	\$ 266,258
Net income (loss) per common share:			
Basic	\$ (1.18)	\$ 3.08	\$ 5.74
Diluted	\$ (1.18)	\$ 3.06	\$ 5.71

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
Year Ended December 31, 2007, 2008 and 2009

	Common Stock	Capital In Excess of Par Value	Accumulated Other Compre- hensive Income	Unearned Compen- sation - Restricted Stock	Retained Earnings	Total
	(In thousands except share amounts)					
Balances, January 1, 2007	\$ 9,257	\$ 333,833	\$ 1,339	\$ —	\$ 813,607	\$ 1,158,036
Comprehensive income:						
Net Income	—	—	—	—	266,258	266,258
Other comprehensive income (net of tax of (\$268) and \$191):						
Change in value of cash flow derivative instruments used as cash flow hedges	—	—	(438)	—	—	(438)
Reclassification— derivative settlements	—	—	259	—	—	259
Total comprehensive income	—	—	—	—	—	266,079
Activity in employee compensation plans (728,228 shares)	23	10,679	—	—	—	10,702
Balances, December 31, 2007	9,280	344,512	1,160	—	1,079,865	1,434,817
Comprehensive income:						
Net Income	—	—	—	—	143,625	143,625
Other comprehensive income (net of tax of \$18,704, \$275 and (\$94)):						
Change in value of cash flow derivative instruments used as cash flow hedges	—	—	31,816	—	—	31,816
Reclassification— derivative settlements	—	—	469	—	—	469
Ineffective portion of derivatives qualifying for cash flow hedge accounting	—	—	(161)	—	—	(161)
Total comprehensive income	—	—	—	—	—	175,749
Activity in employee compensation plans (220,875 shares)	45	22,488	—	—	—	22,533
Balances, December 31, 2008	9,325	367,000	33,284	—	1,223,490	1,633,099
Comprehensive income (loss):						
Net loss	—	—	—	—	(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	—	—	32,307	—	—	32,307
Reclassification— derivative settlements	—	—	(61,690)	—	—	(61,690)
Ineffective portion of derivatives qualifying for cash flow hedge accounting	—	—	557	—	—	557
Total comprehensive loss	—	—	—	—	—	(84,326)
Activity in employee compensation plans (274,705 shares)	80	16,957	—	—	—	17,037
Balances, December 31, 2009	\$ 9,405	\$ 383,957	\$ 4,458	\$ —	\$ 1,167,990	\$ 1,565,810

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2009	2008	2007
	(In thousands)		
OPERATING ACTIVITIES:			
Net income (loss)	\$ (55,500)	\$ 143,625	\$ 266,258
Adjustments to reconcile net income (loss) to net cash provided (used) by operating activities:			
Depreciation, depletion and amortization	177,166	244,912	196,111
Impairment of oil and natural gas properties (Note 2)	281,241	281,966	—
Unrealized (gain) loss on derivatives	1,944	(1,302)	—
(Gain) loss on disposition of assets	(6,224)	725	(185)
Deferred tax expense (benefit)	(32,003)	41,077	80,511
Employee stock compensation plans	10,708	15,863	9,254
Bad debt expense	975	1,543	1,750
ARO liability accretion	2,585	2,174	1,704
Other, net	(130)	(247)	(92)
Changes in operating assets and liabilities increasing (decreasing) cash:			
Accounts receivable	116,472	(34,495)	39,042
Materials and supplies	3,009	3,635	5,343
Prepaid expenses and other	(1,525)	(9,996)	(6,926)
Accounts payable	(7,068)	3,685	(7,296)
Accrued liabilities	(1,410)	684	(9,667)
Contract advances	235	(3,936)	1,764
Net cash provided by operating activities	490,475	689,913	577,571
INVESTING ACTIVITIES:			
Capital expenditures	(316,660)	(782,434)	(478,950)
Producing property and other acquisitions	—	(25,727)	(38,500)
Proceeds from disposition of property and equipment	44,733	4,735	5,309
Acquisition of other assets	—	(2,715)	(192)
Net cash used in investing activities	(271,927)	(806,141)	(512,333)
FINANCING ACTIVITIES:			
Borrowings under line of credit	95,600	397,600	175,800
Payments under line of credit	(265,100)	(318,700)	(229,500)
Proceeds from exercise of stock options	282	2,507	692
Tax (expense) benefit from stock options	(252)	1,449	267
Increase (decrease) in book overdrafts (Note 2)	(48,522)	32,880	(12,010)
Net cash provided by (used in) financing activities	(217,992)	115,736	(64,751)
Net increase (decrease) in cash and cash equivalents	556	(492)	487
Cash and cash equivalents, beginning of year	584	1,076	589
Cash and cash equivalents, end of year	\$ 1,140	\$ 584	\$ 1,076
Supplemental disclosure of cash flow information:			
Cash paid during the year for:			
Interest paid (net of capitalized)	\$ 682	\$ 1,679	\$ 7,135
Income taxes	\$ 12,302	\$ 45,700	\$ 73,417

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 and its subsidiaries.

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

Contract Drilling. Carried out by our subsidiary, Unit Drilling Company and its subsidiaries, 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 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 primary exploration and production operations are conducted in the Anadarko and Arkoma Basins and in the Texas Gulf Coast area with additional properties in the Permian Basin. The majority of our contract drilling and exploration and production activities are oriented toward drilling for and producing natural gas.

Mid-Stream. Through 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 and Pennsylvania.

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.

Management has evaluated and disclosed all material subsequent events through February 23, 2010, which is the date the financial statements in this annual report are filed on Form 10-K.

Drilling Contracts. We recognize revenues and expenses generated from “daywork” drilling contracts as the services are performed, since we do not bear the risk of completion of the well. Under “footage” and “turnkey” contracts, we bear the risk of completion of the well; therefore, revenues and expenses are recognized when the well is substantially completed. Under this method, substantial completion is determined when the well bore reaches the negotiated depth as stated in the contract. The entire amount of a loss, if any, is recorded when the loss is determinable. The costs of uncompleted drilling contracts include expenses incurred to date on “footage” or “turnkey” contracts, which are still in process at the end of the period, and are included in other current assets. Typically, any one of these three types of contracts can be used for the drilling of one well which can take from 20 to 90 days. At December 31, 2009, substantially all of our contracts were daywork contracts of which 26 were multi-well and had

durations which ranged from 6 months to two 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, 2009 we did not have any book overdrafts and at December 31, 2008, book overdrafts were \$48.5 million and included in accounts payable.

Accounts Receivable. Accounts receivable are carried on a gross basis, with no discounting, less an allowance for doubtful accounts. No allowance for doubtful accounts is recognized at the time the revenue which generates the accounts receivable is recognized. 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. During 2009, Questar Corporation was our largest drilling customer and accounted for approximately 35% of our total contract drilling revenues, there was not a third party customer that accounted for more than 10% of our oil and natural gas revenues and ONEOK, Tenaska and ConocoPhillips accounted for approximately 52%, 17% and 15% of our mid-stream revenues, respectively. During 2008, Questar Corporation was our largest drilling customer and accounted for approximately 19% of our total contract drilling revenues, there was not a third party customer that accounted for more than 10% of our oil and natural gas revenues and ONEOK accounted for approximately 79% of our mid-stream revenues, respectively. During 2007, Questar Corporation was our largest drilling customer and accounted for approximately 13% of our total contract drilling revenues, Eagle Energy Partners I, L.P. accounted for approximately 12% of our oil and natural gas revenues and ONEOK and Murphy Oil USA, Inc. accounted for approximately 82% and 10% of our mid-stream revenues, respectively. We had a concentration of cash of \$35.0 million and \$3.8 million at December 31, 2009 and 2008, respectively with one bank.

The use of derivative transactions also involves the risk that the counterparties will be unable to meet the financial terms of the transactions. We considered this non-performance risk with regard to our counterparties and our own non-performance risk in our derivative valuation at December 31, 2009 and determined it was immaterial at that time. At February 12, 2010, Bank of Montreal, Bank of America, N.A., Calyon New York Branch, Comerica Bank and Compass Bank were the counterparties with respect to all of our commodity derivative transactions. At December 31, 2009, the fair values of the net assets (liabilities) we had with each of these counterparties was \$1.5 million, \$6.3 million, \$1.0 million, \$1.1 million and (\$1.4) million, respectively.

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, 2009, 2008 or 2007.

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

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

Goodwill. Goodwill represents the excess of the cost of acquisitions over the fair value of the net assets acquired. Goodwill is not amortized, but an impairment test is performed at least annually to determine whether the fair value has decreased and is performed additionally when events indicate an impairment may have occurred. Goodwill is all related to our contract drilling segment, and accordingly, the impairment test is generally based on the estimated discounted future net cash flows of our drilling segment, utilizing discount rates and other factors in determining the fair value of our drilling segment. No goodwill impairment was recorded for the years ended December 31, 2009, 2008, or 2007. In 2007, we added goodwill of \$5.3 million as a result of the acquisition which closed on June 5, 2007. There were no additions to goodwill in 2008 or 2009. The acquisitions are more fully discussed in Note 3. Goodwill of \$7.4 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, 2009 or 2008. Amortization of \$3.7 million, \$4.4 million and \$3.3 million was recorded in 2009, 2008 and 2007, respectively. Accumulated amortization for 2009 and 2008 was \$12.3 million and \$8.6 million, respectively. Amortization of \$2.6 million, \$1.2 million, \$1.2 million and \$0.7 million is expected to be recorded in 2010, 2011, 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 composite units-of-production method based on proved oil and natural gas reserves. Directly related overhead costs of \$13.2 million, \$15.3 million and \$13.1 million were capitalized in 2009, 2008 and 2007, respectively. Independent petroleum engineers annually audit our internal evaluation of our reserves. The average composite rates used for depreciation, depletion and amortization (DD&A) were \$1.87, \$2.50 and \$2.32 per Mcfe in 2009, 2008 and 2007, 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 \$140.1 million are excluded from the DD&A calculation.

Our DD&A expense on our oil and natural gas properties is calculated each quarter utilizing period end reserve quantities. The new SEC oil and gas reserves measurement and disclosure rules that went into effect as of December 31, 2009 impacted our DD&A expense for the fourth quarter of 2009, increasing DD&A expense by \$1.2 million (or \$0.02 per share) for the quarter and year ended December 31, 2009.

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%. Effective December 31, 2009, full cost companies are required to use 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, to calculate the discounted future revenues. Previously, the price was based on the single-day period-end price. 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 ended March 31, 2009 as a result of a decline in commodity prices as compared to those existing at year end 2008. We recorded a non-cash ceiling test write down of \$282.0 million pre-tax (\$175.5 million, net of tax) during the year ended December 31, 2008 as a result of declines in commodity prices. No ceiling test write down was required during the year ended December 31, 2007.

Derivative instruments qualifying as cash flow hedges were included in the computation of limitation on capitalized costs in the March 31, 2009 and December 31, 2008 ceiling test calculations and the effect was a \$197.9 million and a \$96.0 million, respectively, pre-tax increase in the discounted net cash flows of our oil and natural gas properties. Our qualifying cash flow hedges as of March 31, 2009 which consisted of swaps and collars, covered 30.3 Bcfe and 33.2 Bcfe in 2009 and 2010, respectively, and as of December 31, 2008 covered 40.2 Bcfe and 23.7 Bcfe in 2009 and 2010, respectively.

We did not have a ceiling test impairment for the quarter ended December 31, 2009. Our qualifying cash flow hedges as of December 31, 2009, which consisted of swaps and collars, covered 36.5 Bcfe in 2010. The effect of these cash flow hedges was an \$88.5 million pre-tax increase in the discounted net cash flows of our oil and natural gas properties. At December 31, 2009, without the benefit of the discounted value of our commodity hedges, we would have been required to recognize an impairment to our full cost pool of approximately \$41.6 million pre-tax (\$25.9 million, net of tax). Our oil and natural gas hedging activities are discussed in Note 13 of our Notes to Consolidated Financial Statements.

Our contract drilling segment provides drilling services for our exploration and production segment. The contracts for these services are issued under the same conditions and rates as the contracts entered into with unrelated third parties. During 2009, the contract drilling segment drilled 38 wells for our exploration and production segment. As required by the SEC, the profit received by the contract drilling segment of \$1.3 million, \$27.9 million and \$22.7 million during 2009, 2008 and 2007, respectively, was used to reduce the carrying value of our oil and natural gas properties rather than being included in its operating profit.

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 for fiduciary liability to \$1.0 million for drilling rig physical damage. 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.

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 15 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. In the third quarter of 2007, the Internal Revenue Service completed its review of our 2004 federal tax return and no adjustments to the return were assessed.

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, 2009 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.

The FASB Accounting Standards Codification. FASB Accounting Standards Codification (ASC) became effective during the third quarter of 2009. ASC 105, *Generally Accepted Accounting Principles*, (guidance formerly reflected in FAS168) established the ASC as the single source of authoritative U.S. generally accepted accounting principles (U.S. GAAP) recognized by the FASB to be applied by nongovernmental entities. Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative U.S. GAAP for SEC registrants. The ASC supersedes all existing non-SEC accounting and reporting standards. All other nongrandfathered non-SEC accounting literature not included in the ASC will become nonauthoritative. Following ASC 105, the FASB will not issue new standards in the form of Statements, FASB Staff Positions, or Emerging Issues Task Force Abstracts. Instead, the FASB will issue Accounting Standards Updates, which will serve only to: (a) update the ASC; (b) provide background information about the guidance; and (c) provide the basis for

conclusions on the change(s) in the ASC. The adoption of this standard has changed how we reference various elements of U.S. GAAP in our financial statement disclosures, but has no impact on our financial position, results of operation or cash flows.

Fair Value Measurements and Disclosures. Beginning in 2008, we adopted the effective provisions of ASC 820 *Fair-Value Measurements* (formerly FAS 157.) ASC 820 defines fair value in applying GAAP, establishes a framework for measuring fair value and expands disclosures about fair-value measurements. ASC 820 does not change existing guidance as to whether or not an instrument is carried at fair value.

In February 2008, the FASB delayed the effective date of ASC 820 for one year for certain nonfinancial assets and nonfinancial liabilities, except those recognized or disclosed at fair value in the financial statements on a recurring basis. On January 1, 2009, we adopted, the delayed provisions of ASC 820 related to nonfinancial assets and nonfinancial liabilities that are not required or permitted to be measured at fair value on a recurring basis. The adoption of the delayed provisions did not have a material impact on our financial statements.

Modernization of Oil and Gas Reporting. On December 31, 2008, the Securities and Exchange Commission (SEC) adopted major revisions to its rules governing oil and gas company reporting requirements. These include provisions that permit the use of new technologies to determine proved reserves, and that allow companies to disclose their probable and possible reserves to investors. The current rules limit disclosure to only proved reserves. The new rules also require companies to report the independence and qualifications of the auditor of the reserve estimates and file reports when a third party is relied on to prepare reserves estimates. The new rules also require that oil and gas reserves be reported and the full cost ceiling value calculated using an average price based on the first-of-month posted price for each month in the prior 12-month period. On January 5, 2010, the FASB issued Accounting Standards update (ASU) 2010-03 - *Extractive Activities - Oil and Gas (ASC 932): Oil and Gas Reserve Estimation and Disclosures*, an update of ASC 932 *Extractive Activities - Oil and Gas*, which subsequently aligns the reserve estimation, disclosure requirements, and definitions of ASC 932 with the disclosure requirements of the new rules issued by the SEC. The new oil and gas reserve measurement and reporting requirements were adopted for oil and gas reserves as of December 31, 2009. For accounting purposes, the new requirements constitute a change in accounting principle inseparable from a change in estimate. As such, prior reserve disclosures were not modified and the impact of the new requirements on our oil and gas reserves was reflected as a change in estimate. As previously noted, reserves and discounted cash flows prepared using the new rules were used in the calculation of DD&A for the fourth quarter of 2009 and the ceiling test at December 31, 2009.

Interim Disclosures about Fair Value of Financial Instruments. On June 30, 2009, we implemented certain provisions of ASC 825, *Financial Instruments*, (guidance formerly reflected in FASB Staff Position (FSP) Statement No. 107-1 and Accounting Principles Board (APB) 28-1, *Interim Disclosures about Fair Value of Financial Instruments*). The new provisions require disclosures about fair value of financial instruments in interim financial information. We are required to disclose in the body or in the accompanying notes of our summarized financial information for interim reporting periods and in our financial statements for annual reporting periods, the fair value of all financial instruments for which it is practicable to estimate that value, whether recognized or not recognized in the statement of financial position. We have included the required disclosure in Note 6 of our Notes to Consolidated Financial Statements.

Subsequent Events. On June 30, 2009, we implemented certain provisions of ASC 855, *Subsequent Events*, (guidance formerly reflected in FAS165, *Subsequent Events*). The new provision establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. ASC 855 provides:

- The period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements;
- The circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and
- The disclosures that an entity should make about events or transactions that occurred after the balance sheet date.

Consolidations of Variable Interest Entities. On June 12, 2009, the FASB issued ASU 2009-17 - *Consolidations (ASC 810): Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities*, the FASB amended the authoritative guidance on consolidation which requires an enterprise to perform an analysis to determine whether the enterprise's variable interest or interests give it a controlling financial interest in a variable interest entity. In order to be the primary beneficiary of a variable interest entity, an enterprise must have (a) the power to direct the activities of a variable interest entity that most significantly impact the entity's economic performance, and (b) the obligation to absorb losses of the entity that could potentially be significant to the variable interest entity or the right to receive benefits from the entity that could potentially be significant to the variable interest entity. Along with these criteria, an enterprise is now required to assess whether it has an implicit financial responsibility to ensure that a variable interest entity operates as designed when determining (a) above. Also, the enterprise is required to perform ongoing reassessments of whether an enterprise is the primary beneficiary of a variable interest entity. The quantitative approach previously required for determining the primary beneficiary has been eliminated. Additional disclosures are now required in order to provide users of financial statements with more transparent information about an enterprise's involvement in a variable interest entity. This amendment is effective for the first fiscal year beginning after November 15, 2009. This ASU does not currently have a material impact on us.

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 is the first interim or annual reporting period beginning after December 15, 2009, except for the gross presentation of the Level 3 roll forward information, which is required for annual reporting periods beginning after December 15, 2010 and for interim reporting periods within those years. This statement will not have a significant impact on us due to it only requiring enhanced disclosures.

Note 3. Acquisitions

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 September 2008, we completed an acquisition consisting of a 75% working interest in four producing wells and other proved undeveloped properties for \$22.2 million along with working interests in undeveloped leasehold valued at approximately \$3.5 million, all located in the Texas Panhandle region.

On January 18, 2008, we purchased a 50% interest in a 6,800 gross-acre leasehold that we did not already own in our Segno area of operations located in Hardin County, Texas. Included in the purchase were five producing wells with 4.9 Bcfe of estimated proved reserves and current production of 2.8 MMcf of natural gas per day and 88.2 barrels of condensate. The purchase price was \$16.8 million which consisted of \$15.8 million allocated to the reserves of the wells and \$1.0 million allocated to the undeveloped leasehold.

On June 5, 2007, our subsidiary, Unit Drilling Company, closed the purchase of a privately owned drilling company operating primarily in the Texas Panhandle. This acquisition included nine drilling rigs, drill pipe and collars, a fleet of 11 trucks, an office, shop, equipment yard and personnel. The drilling rigs range from 800 horsepower to 1,000 horsepower with depth capacities rated from 10,000 to 15,000 feet. Eight of the acquired drilling rigs were operational at the time of purchase and the remaining drilling rig is being refurbished and is anticipated to become operational in March of 2008. The financial results of this acquisition are included in our statement of income from June 5, 2007 forward. The total consideration paid in this acquisition was allocated as follows (in thousands):

Drilling rigs	\$	39,326
Spare drilling equipment		1,613
Drill pipe and collars		7,784
Trucks		1,551
Other vehicles		190
Yard and office		846
Goodwill		5,285
Deferred income taxes		(18,095)
Total consideration	\$	<u>38,500</u>

Note 4. Earnings (Loss) Per Share

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

	<u>Income</u> <u>(Numerator)</u>	<u>Weighted</u> <u>Shares</u> <u>(Denominator)</u>	<u>Per-Share</u> <u>Amount</u>
	(In thousands except per share amounts)		
For the year ended December 31, 2009:			
Basic earnings (loss) per common share	\$ (55,500)	46,990	\$ (1.18)
Effect of dilutive stock options, restricted stock and SARs	—	—	—
Diluted earnings (loss) per common share	<u>\$ (55,500)</u>	<u>46,990</u>	<u>\$ (1.18)</u>
For the year ended December 31, 2008:			
Basic earnings per common share	\$ 143,625	46,586	\$ 3.08
Effect of dilutive stock options, restricted stock and SARs	—	323	(0.02)
Diluted earnings per common share	<u>\$ 143,625</u>	<u>46,909</u>	<u>\$ 3.06</u>
For the year ended December 31, 2007:			
Basic earnings per common share	\$ 266,258	46,366	\$ 5.74
Effect of dilutive stock options and restricted stock	—	287	(0.03)
Diluted earnings per common share	<u>\$ 266,258</u>	<u>46,653</u>	<u>\$ 5.71</u>

Due to the net loss for 2009, approximately 373,000 weighted average shares related to stock options, restricted stock and stock settled stock appreciation rights (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:

	<u>2009</u>	<u>2008</u>	<u>2007</u>
Options and SARs	<u>358,821</u>	<u>84,900</u>	<u>105,655</u>
Average exercise price	<u>\$ 47.83</u>	<u>\$ 64.39</u>	<u>\$ 56.33</u>

Note 5. Accrued Liabilities

Accrued liabilities consisted of the following as of December 31:

	<u>2009</u>	<u>2008</u>
	<u>(In thousands)</u>	
Employee costs	\$ 13,307	\$ 18,518
Lease operating expense accrual	6,244	6,720
Taxes	5,085	20,666
Other	9,935	5,755
Total accrued liabilities	<u>\$ 34,571</u>	<u>\$ 51,659</u>

Note 6. Long-Term Debt and Other Long-Term Liabilities

Long-Term Debt

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

	<u>2009</u>	<u>2008</u>
	<u>(In thousands)</u>	
Revolving credit facility, with interest, including the effect of hedging, at December 31, 2009 and 2008 of 4.3% and 3.4%, respectively	\$ 30,000	\$ 199,500
Less current portion	—	—
Total long-term debt	<u>\$ 30,000</u>	<u>\$ 199,500</u>

On December 23, 2008, we entered into a First Amendment to our existing First Amended and Restated Senior Credit Agreement (Credit Facility) with a maximum credit amount of \$400.0 million maturing on May 24, 2012. This amendment increased the lenders' commitment by \$50.0 million to an aggregate of \$325.0 million. Borrowings under the Credit Facility are limited to a commitment amount that we can elect. As of December 31, 2009, the commitment amount was \$325.0 million. We are charged a commitment fee of 0.375 to 0.50 of 1% on the amount available but not borrowed with the rate varying based on the amount borrowed as a percentage of the total borrowing base amount. When we entered into the Credit Facility, we incurred origination, agency and syndication fees of \$737,500 and \$478,125 associated with the December 23, 2008 First Amendment, which are being amortized over the life of the agreement. The average interest rate for 2009, which includes the effect of our interest rate swaps, was 4.0%.

The lenders' aggregate commitment is limited to the lesser of the amount of the value of the borrowing base or \$400.0 million. The amount of the borrowing base, which is subject to redetermination on April 1 and October 1 of each year, is based primarily on a percentage of the discounted future value of our oil and natural gas reserves and, to a lesser extent, the loan value the lenders reasonably attribute to the cash flow (as defined in the Credit Facility) of our mid-stream operations. The current borrowing base is \$475.0 million. We or the lenders may request a onetime special redetermination of the borrowing base amount between each scheduled redetermination. In addition, we may request a redetermination following the consummation of an acquisition meeting the requirements defined in the Credit Facility.

At our election, any part of the outstanding debt under the Credit Facility may be fixed at a London Interbank Offered Rate (LIBOR) for a 30, 60, 90 or 180 day term. During any LIBOR funding period, the outstanding principal balance of the promissory note to which the LIBOR option applies may be repaid on three days prior notice to the administrative agent and on our payment of any applicable funding indemnification amounts. Interest on the LIBOR is computed at the LIBOR base applicable for the interest period plus 1.75% to 2.50% depending on the level of debt as a percentage of the borrowing base and payable at the end of each term, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the BOK Financial Corporation (BOKF) National Prime Rate, which in no event will be less than LIBOR plus 1.00%, 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, 2009, all of our then outstanding borrowings of \$30.0 million were subject to LIBOR.

The Credit Facility prohibits:

- the payment of dividends (other than stock dividends) during any fiscal year in excess of 25% 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 Facility also requires that we have at the end of each quarter:

- consolidated net worth of at least \$900 million;
- a current ratio (as defined in the Credit Facility) of not less than 1 to 1; and
- a leverage ratio of long-term debt to consolidated EBITDA (as defined in the Credit Facility) for the most recently ended rolling four fiscal quarters of no greater than 3.50 to 1.0.

As of December 31, 2009, we were in compliance with the covenants of the Credit Facility.

Based on the borrowing rates currently available to us for debt with similar terms and maturities and consideration of our non-performance risk, long-term debt at December 31, 2009 and 2008 approximates its fair value.

At December 31, 2009, the carrying values of cash and cash equivalents, accounts receivable, accounts payable, other current assets and current liabilities on the consolidated balance sheets approximate fair value because of their short term nature.

Other Long-Term Liabilities

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

	<u>2009</u>	<u>2008</u>
	<u>(In thousands)</u>	
ARO liability	\$ 56,404	\$ 49,230
Workers' compensation	22,974	23,473
Separation benefit plans	4,681	6,435
Gas balancing liability	3,263	3,364
Deferred compensation plan	2,004	2,030
Retirement agreements	—	110
	<u>89,326</u>	<u>84,642</u>
Less current portion	<u>9,342</u>	<u>10,615</u>
Total other long-term liabilities	<u>\$ 79,984</u>	<u>\$ 74,027</u>

Estimated annual principle payments under the terms of debt and other long-term liabilities from 2010 through 2014 are \$9.3 million, \$3.9 million, \$46.2 million, \$3.2 million and \$2.5 million, respectively.

Note 7. Asset Retirement Obligations

We are required to record the fair value of liabilities associated with the retirement of long-lived assets. Our oil and natural gas wells are required to be plugged and abandoned when the oil and natural gas reserves in the wells are depleted or the wells are no longer able to produce. The plugging and abandonment expense for a well is recorded in the period in which the liability is incurred (at the time the well is drilled or acquired). We do not have any assets restricted for settling these well ARO liabilities.

The following table shows the activity for our retirement obligation for plugging liability for the years ending December 31:

	<u>2009</u>	<u>2008</u>
	(In thousands)	
ARO liability, January 1:	\$ 49,230	\$ 33,191
Accretion of discount	2,585	2,174
Liability incurred	3,447	4,206
Liability settled	(1,331)	(796)
Revision of estimates ⁽¹⁾	2,473	10,455
ARO liability, December 31:	<u>56,404</u>	<u>49,230</u>
Less current portion	1,080	1,113
Total long-term ARO liability	<u>\$ 55,324</u>	<u>\$ 48,117</u>

(1) ARO liability estimates were revised upward in 2009 and 2008 due to the increase in the cost of contract services utilized 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:

	<u>2009</u>	<u>2008</u>	<u>2007</u>
	(In thousands)		
Income tax expense (benefit) computed by applying the statutory rate	\$ (30,704)	\$ 78,943	\$ 144,694
State income tax, net of federal benefit	(2,409)	4,547	6,155
Domestic production activities deduction	—	(2,081)	(3,682)
Statutory depletion and other	887	545	(14)
Income tax expense (benefit)	<u>\$ (32,226)</u>	<u>\$ 81,954</u>	<u>\$ 147,153</u>

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

	<u>2009</u>	<u>2008</u>	<u>2007</u>
	(In thousands)		
Current taxes:			
Federal	\$ (5,124)	\$ 38,535	\$ 60,557
State	4,901	2,342	6,085
	<u>(223)</u>	<u>40,877</u>	<u>66,642</u>
Deferred taxes:			
Federal	(23,510)	37,180	74,721
State	(8,493)	3,897	5,790
	<u>(32,003)</u>	<u>41,077</u>	<u>80,511</u>
Total provision	<u>\$ (32,226)</u>	<u>\$ 81,954</u>	<u>\$ 147,153</u>

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

	<u>2009</u>	<u>2008</u>
	(In thousands)	
Deferred tax assets:		
Allowance for losses and nondeductible accruals	\$ 41,882	\$ 37,835
Net operating loss carryforward	2,941	2,248
Alternative minimum tax credit carryforward	<u>8,857</u>	<u>—</u>
	53,680	40,083
Deferred tax liability:		
Depreciation, depletion, amortization and impairment	<u>(485,573)</u>	<u>(504,677)</u>
Net deferred tax liability	(431,893)	(464,594)
Current deferred tax asset	14,423	12,467
Non-current—deferred tax liability	<u>\$ (446,316)</u>	<u>\$ (477,061)</u>

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, 2009, we have net operating loss carryforwards of approximately \$5.4 million which expire from 2015 to 2021.

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 202,655, 89,910 and 83,277 shares of common stock and recognized expense of \$3.6 million, \$5.0 million and \$4.8 million in 2009, 2008 and 2007, 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, 2009 and 2008 was \$2.0 million for both years. We recognized payroll expense and recorded a liability at the time of deferral.

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

On December 31, 2008, we amended all three Plans to be in compliance with Section 409A of the Internal Revenue Code of 1986, as amended. The key amendments to the Plans address, among other things, when distributions may be made, the timing of payments, and the circumstances under which employees become eligible to receive benefits. None of the amendments materially increase the benefits, grants or awards issuable under the Plans. We recognized expense of \$1.5 million, \$1.6 million and \$1.5 million in 2009, 2008 and 2007, 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 15 oil and gas limited partnerships. Three were formed for investment by third parties and eleven (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. An additional third party partnership, the 1979 Oil and Gas Limited Partnership was dissolved on July 1, 2003. Employee partnerships have been formed for each year beginning with 1984. 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 2009, 2008 and 2007) and to the directors of Unit.

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

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

	<u>2009</u>	<u>2008</u>	<u>2007</u>
	(In thousands)		
Contract drilling	\$ 368	\$ 916	\$ 729
Well supervision and other fees	\$ 352	\$ 375	\$ 377
General and administrative expense reimbursement	\$ 376	\$ 584	\$ 444

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.

Note 11. Shareholder Rights Plan

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

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

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

Note 12. Stock-Based Compensation

In 2009, 2008 and 2007, we recognized stock compensation expense for restricted stock awards, stock options and SARs of \$9.2 million, \$11.1 million and \$4.8 million, respectively, and capitalized stock compensation cost for oil and natural gas properties of \$2.1 million, \$3.3 million and \$1.2 million, respectively. The tax benefit related to this stock based compensation was \$2.6 million, \$4.1 million and \$2.1 million, respectively. The remaining unrecognized compensation cost related to unvested awards at December 31, 2009 is approximately \$4.9 million with \$1.1 million of this amount anticipated to be capitalized. The weighted average period of time over which this cost will be recognized is 0.4 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:

	<u>2009</u>	<u>2008</u>	<u>2007</u>
Options granted	3,496	28,000	28,000
Stock appreciation rights	—	—	101,236
Estimated fair value (in millions)	\$ 0.1	\$ 0.7	\$ 2.9
Estimate of stock volatility	0.41	0.32	0.33 to 0.44
Estimated dividend yield	—%	—%	—%
Risk free interest rate	2%	3%	3.75 to 5%
Expected life range based on prior experience (in years)	5	5	5 to 8
Forfeiture rate	5%	5%	0 to 11%

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;
- 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, 2007	44,665	\$ 51.76
Granted	101,236	44.31
Exercised	—	—
Forfeited	—	—
Outstanding at December 31, 2007	145,901	46.59
Granted	—	—
Exercised	—	—
Forfeited	—	—
Outstanding at December 31, 2008	145,901	46.59
Granted	—	—
Exercised	—	—
Forfeited	—	—
Outstanding at December 31, 2009	145,901	\$ 46.59

There were no SARs granted in 2009 or 2008. The SARs granted in 2007 vest in thirds annually with the first vesting period on January 5, 2009. The SARs expire after 10 years from the date of the grant. In 2009 and 2008, 48,633 shares and 14,891 shares vested and no shares vested in 2007. Fair value of SARs at grant date in 2007 was \$2.3 million. The aggregate intrinsic value of the 145,901 shares outstanding subject to vesting at December 31, 2009 was zero with a weighted average remaining contractual term of 7.7 years.

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, 2007	23,381	\$ 51.76
Granted	616,907	46.95
Vested	(4,234)	51.76
Forfeited	—	—
Nonvested at December 31, 2007	636,054	47.09
Granted	30,855	55.44
Vested	(20,245)	50.38
Forfeited	(29,516)	47.19
Nonvested at December 31, 2008	617,148	47.40
Granted	—	—
Vested	(68,836)	46.18
Forfeited	(41,241)	48.69
Nonvested at December 31, 2009	507,071	\$ 47.46

The restricted stock awards vest in periods ranging from one to three years. There was no restricted stock granted in 2009. The fair value of the restricted stock granted in 2008 and 2007 at the grant date was \$1.5 million and \$26.3 million, respectively. The aggregate intrinsic value of the 68,836 shares of restricted stock on their 2009 vesting date was \$2.0 million. The aggregate intrinsic value of the 507,071 shares outstanding subject to vesting at December 31, 2009 was \$21.6 million with a weighted average remaining life of 0.6 years.

As a result of the approval of the adoption of the Unit Corporation Stock and Incentive Compensation Plan at our shareholders' annual meeting on May 3, 2006, no further grants were made under the prior Employee Stock Bonus Plan. Under the terms of the old plan, awards were granted to employees in either cash or stock or a combination thereof, and were payable in a lump sum or in installments subject to certain restrictions. On December 13, 2005, 38,190 shares (in the form of restricted stock awards) were granted under the plan one half of which was distributed on January 1, 2007 and the other half was distributed on January 1, 2008. No shares vested in 2006.

Activity pertaining to restricted stock awards granted under the Employee Stock Bonus Plan is as follows:

	Number of Shares	Weighted Average Grant Date Price
Nonvested at January 1, 2007	37,452	\$ 58.30
Granted	—	—
Vested	(18,749)	58.30
Forfeited	(329)	58.30
Nonvested at December 31, 2007	18,374	58.30
Granted	—	—
Vested	(18,374)	58.30
Forfeited	—	—
Nonvested at December 31, 2008	—	—
Granted	—	—
Vested	—	—
Forfeited	—	—
Nonvested at December 31, 2009	—	\$ —

The grant date fair value of the 18,749 shares vesting in 2007 and the 18,374 shares vesting in 2008 was \$1.0 million each. As of December 31, 2008 all shares in this plan have been vested or forfeited.

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.

Activity pertaining to the Stock Option Plan is as follows:

	Number of Shares	Weighted Average Exercise Price
Outstanding at January 1, 2007	381,350	\$ 25.81
Granted	—	—
Exercised	(25,850)	23.31
Forfeited	(1,000)	37.83
Outstanding at December 31, 2007	354,500	25.96
Granted	—	—
Exercised	(122,810)	18.75
Forfeited	(3,400)	35.20
Outstanding at December 31, 2008	228,290	29.68
Granted	—	—
Exercised	(4,065)	23.45
Forfeited	(4,600)	38.60
Outstanding at December 31, 2009	<u>219,625</u>	<u>\$ 29.61</u>

The total grant date fair value of the 27,100, 47,070 and 68,470 shares vesting in 2009, 2008 and 2007 was \$1.0 million, \$0.8 million and \$1.0 million. The intrinsic value of options exercised in 2009 was \$0.1 million. Total cash received from the options exercised in 2009 was \$0.1 million.

Outstanding Options at December 31, 2009			
Exercise Prices	Number of Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price
\$16.69 - \$19.04	49,300	2.2 years	\$ 18.16
\$21.50 - \$26.28	58,905	3.9 years	\$ 22.83
\$34.75 - \$37.83	107,920	5.0 years	\$ 37.75
\$53.90 - \$60.32	3,500	6.2 years	\$ 53.90

The aggregate intrinsic value of the 219,625 shares outstanding subject to options at December 31, 2009 was \$2.9 million with a weighted average remaining contractual term of 4.1 years.

<u>Exercise Prices</u>	<u>Exercisable Options At December 31, 2009</u>	
	<u>Number of Shares</u>	<u>Weighted Average Exercise Price</u>
\$16.69 - \$19.04	49,300	\$ 18.16
\$21.50 - \$22.95	58,905	\$ 22.83
\$34.83 - \$37.83	102,420	\$ 37.78
\$53.90 - \$60.32	2,100	\$ 53.90

Options for 212,725, 191,390 and 267,130 shares were exercisable with weighted average exercise prices of \$29.25, \$27.92 and \$22.97 at December 31, 2009, 2008 and 2007, respectively. The aggregate intrinsic value of shares exercisable at December 31, 2009 was \$2.8 million with a weighted average remaining contractual term of 4.1 years.

On May 29, 2009, our company through its 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.

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 cannot vest before the stockholders approve the amended plan at the next stockholders annual meeting, and will be void in the event such approval is not obtained.

Activity pertaining to the Directors' Plan is as follows:

	<u>Number of Shares</u>	<u>Weighted Average Exercise Price</u>
Outstanding at January 1, 2007	120,500	\$ 33.78
Granted	28,000	57.63
Exercised	(6,000)	14.81
Outstanding at December 31, 2007	142,500	39.26
Granted	28,000	73.26
Exercised	(17,500)	27.30
Outstanding at December 31, 2008	153,000	46.85
Granted	3,496	31.30
Exercised	(13,000)	14.74
Outstanding at December 31, 2009	143,496	\$ 49.38

The total grant date fair value of the 3,496, 28,000 and 28,000 shares vesting in 2009, 2008 and 2007, respectively, was \$0.1 million, \$0.7 million and \$0.6 million, respectively. The intrinsic value of options exercised in 2009 was \$0.3 million. Total cash received from options exercised in 2009 was \$0.2 million.

Outstanding and Exercisable Options at December 31, 2009			
Exercise Prices	Number of Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price
\$17.54	7,000	1.3 years	\$ 17.54
\$20.10 - \$20.46	17,500	2.9 years	\$ 20.32
\$28.23 - \$39.50	34,996	5.3 years	\$ 34.17
\$57.63 - \$73.26	84,000	7.3 years	\$ 64.43

Options for 143,496, 153,000 and 142,500 shares were exercisable with weighted average exercise prices of \$49.38, \$46.85 and \$39.26 at December 31, 2009, 2008 and 2007, respectively. The aggregate intrinsic value of the shares outstanding subject to options at December 31, 2009 was \$0.9 million with a weighted average remaining contractual term of 6.0 years.

Note 13. Derivatives

On January 1, 2009, we implemented new accounting guidance which requires enhanced disclosures about a company's derivative activities and how the related hedged items affect a company's financial position, financial performance and cash flows.

Interest Rate Swaps

From time to time we have entered into interest rate swaps to help manage our exposure to possible future interest rate increases. Under these transactions we have swapped the variable interest rate we would otherwise incur on a portion of our bank debt for a fixed interest rate. As of December 31, 2009, we had two outstanding interest rate swaps both of which were cash flow hedges. There was no material amount of ineffectiveness.

Term	Amount	Fixed Rate	Floating Rate
December 2007 – May 2012	\$ 15,000,000	4.53%	3 month LIBOR
December 2007 – May 2012	\$ 15,000,000	4.16%	3 month LIBOR

Commodity Derivatives

We have entered into various types of derivative instruments covering a portion of our projected natural gas, natural gas liquids and oil production to reduce our exposure to market price volatility. Our decision on the quantity and price at which we choose to hedge certain of our production is based, in part, on our view of current and future market conditions. As of December 31, 2009, our derivative instruments consisted of the following types of swaps and collars:

- *Swaps.* We receive or pay a fixed price for the hedged commodity and pay or receive a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.
- *Collars.* A collar contains a fixed floor price (put) and a ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, we receive the fixed price and pay the market price. If the market price is between the call and the put strike price, no payments are due from either party.

- *Basis Swaps.* We receive or pay the NYMEX settlement value plus or minus a fixed delivery point price for the hedged commodity and pay or receive the published index price at the specified delivery point. We use basis swaps to hedge the price risk between NYMEX and its physical delivery points.

Oil and Natural Gas Segment:

At December 31, 2009, the following cash flow hedges were outstanding:

<u>Term</u>	<u>Commodity</u>	<u>Hedged Volume</u>	<u>Weighted Average Fixed Price for Swaps</u>	<u>Hedged Market</u>
Jan'10 – Dec'10	Crude oil - collar	1,000 Bbl/day	\$67.50 put & \$81.53 call	WTI – NYMEX
Jan'10 – Dec'10	Crude oil – swap	1,500 Bbl/day	\$61.36	WTI – NYMEX
Jan'10 – Dec'10	Natural gas – swap	15,000 MMBtu/day	\$ 7.20	IF – NYMEX (HH)
Jan'10 – Dec'10	Natural gas – swap	20,000 MMBtu/day	\$ 6.89	IF – Tenn Zone 0
Jan'10 – Dec'10	Natural gas – swap	30,000 MMBtu/day	\$ 6.12	IF – CEGT
Jan'10 – Dec'10	Natural gas – swap	20,000 MMBtu/day	\$ 5.67	IF – PEPL
Jan'10 – Dec'10	Natural gas – basis differential swap	10,000 MMBtu/day	(\$0.79)	PEPL – NYMEX

The following tables present the fair values and locations of derivative instruments recorded in the balance sheet:

<u>Balance Sheet Location</u>		<u>Derivative Assets</u>	
		<u>Fair Value</u>	
		<u>December 31, 2009</u>	<u>December 31, 2008</u>
		<u>(In thousands)</u>	
Derivatives designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative assets	\$ 9,945	\$ 51,130
Long-term	Non-current derivative assets	—	5,218
Total derivatives designated as hedging instruments		<u>9,945</u>	<u>56,348</u>
Derivatives not designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative assets	—	1,047
Total derivatives not designated as hedging instruments		<u>—</u>	<u>1,047</u>
Total derivative assets		<u>\$ 9,945</u>	<u>\$ 57,395</u>
<u>Balance Sheet Location</u>		<u>Derivative Liabilities</u>	
		<u>Fair Value</u>	
		<u>December 31, 2009</u>	<u>December 31, 2008</u>
		<u>(In thousands)</u>	
Derivatives designated as hedging instruments			
Interest rate swaps:			
Current	Current portion of derivative liabilities	\$ 806	\$ 736
Long-term	Long-term derivative liabilities	1,142	1,780
Commodity derivatives:			
Current	Current portion of derivative liabilities	1,424	745
Long-term	Long-term derivative liabilities	—	—
Total derivatives designated as hedging instruments		<u>3,372</u>	<u>3,261</u>
Derivatives not designated as hedging instruments			
Commodity derivatives (basis swaps):			
Current	Current portion of derivative liabilities	—	—
Total derivatives not designated as hedging instruments		<u>—</u>	<u>—</u>
Total derivative liabilities		<u>\$ 3,372</u>	<u>\$ 3,261</u>

To the extent that a legal right of set-off exists, we net the value of our derivative arrangements with the same counterparty in the accompanying consolidated balance sheets.

We recognize the effective portion of changes in fair value as accumulated other comprehensive income (loss) (OCI), 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, 2009 and 2008, we had a gain of \$4.5 million and \$33.3 million, net of tax, respectively, in accumulated OCI.

Based on the market prices at December 31, 2009, we expect to transfer approximately \$4.7 million, net of tax, of the gain included in the balance in accumulated OCI to earnings during the next 12 months in the related month of settlement. The interest rate swaps and the commodity derivative instruments as of December 31, 2009 are expected to mature by May 2012 and December 2010, respectively.

Certain derivatives do not qualify for designation as cash flow hedges. We had two basis swaps that did not qualify as cash flow hedges that expired in December 2009. Changes in the fair value of these non-qualifying derivatives that occur before their maturity (i.e., temporary fluctuations in value) are reported in the consolidated statements of operations within oil and natural gas revenues. Changes in the fair value of derivative instruments 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 oil and natural gas revenues.

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

<u>Derivatives in Cash Flow Hedging Relationships</u>	<u>Amount of Gain or (Loss) Recognized in Accumulated OCI on Derivative (Effective Portion) ⁽¹⁾</u>	
	<u>2009</u>	<u>2008</u>
	(In thousands)	
Interest rate swaps	\$ (1,204)	\$ (1,585)
Commodity derivatives	5,662	34,869
Total	<u>\$ 4,458</u>	<u>\$ 33,284</u>

(1) Net of taxes.

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

<u>Derivative Instrument</u>	<u>Location of Gain or (Loss) Reclassified from Accumulated OCI into Income & Location of Gain or (Loss) Recognized in Income</u>	<u>Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income ⁽¹⁾</u>		<u>Amount of Gain or (Loss) Recognized in Income ⁽²⁾</u>	
		<u>2009</u>	<u>2008</u>	<u>2009</u>	<u>2008</u>
		(In thousands)			
Commodity derivatives	Oil and natural gas revenue	\$ 100,286	\$ (1,010)	\$ (897)	\$ 255
Commodity derivatives	Gas gathering and processing revenue	—	2,022	—	—
Commodity derivatives	Gas gathering and processing operating costs	—	(1,438)	—	—
Interest rate swaps	Interest, net	(1,036)	(318)	—	—
	Total	<u>\$ 99,250</u>	<u>\$ (744)</u>	<u>\$ (897)</u>	<u>\$ 255</u>

(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	
		2009	2008
(In thousands)			
Commodity derivatives (basis swaps)	Oil and natural gas revenue	\$ (3,469)	\$ 1,047
Total		<u>\$ (3,469)</u>	<u>\$ 1,047</u>

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 (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, 2009			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Financial assets (liabilities):				
Interest rate swaps	\$ —	\$ —	\$ (1,948)	\$ (1,948)
Commodity derivatives	\$ —	\$ (11,427)	\$ 19,948	\$ 8,521

	December 31, 2008			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Financial assets (liabilities):				
Interest rate swaps	\$ —	\$ —	\$ (2,516)	\$ (2,516)
Commodity derivatives	\$ —	\$ (1,858)	\$ 58,508	\$ 56,650

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. The fair values of our crude oil swaps are measured using estimated internal discounted cash flow calculations using NYMEX futures index.

Level 3 Fair Value Measurements

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

Commodity Derivatives. The fair values of our natural gas and natural gas liquids swaps, basis swaps and crude oil and natural gas collars 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, 2009		For the Year Ended December 31, 2008	
	Interest Rate Swaps	Commodity Swaps and Collars	Interest Rate Swaps	Commodity Swaps and Collars
	(In thousands)			
Beginning of period	\$ (2,516)	\$ 58,508	\$ (153)	\$ 2,625
Total gains or losses (realized and unrealized):				
Included in earnings (loss) ⁽¹⁾	(1,036)	100,018	(317)	3,923
Included in other comprehensive income (loss)	568	(36,616)	(2,363)	54,581
Purchases, issuance and settlements	1,036	(101,962)	317	(2,621)
End of period	<u>\$ (1,948)</u>	<u>\$ 19,948</u>	<u>\$ (2,516)</u>	<u>\$ 58,508</u>
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, 2009	\$ —	\$ (1,944)	\$ —	\$ 1,302

(1) Interest rate swaps and commodity sales swaps and collars are reported in the consolidated statements of operations in interest expense and revenues, respectively. Our mid-stream natural gas purchase swaps are reported in the consolidated statements of operations in expense.

We evaluated the non-performance risk with regard to our counterparties and our own non-performance risk in our valuation at December 31, 2009 and determined it was immaterial.

Note 15. Commitments and Contingencies

We lease office space or yards in Tulsa, Oklahoma; Houston, Texas; Englewood and Denver, Colorado; Pinedale, Wyoming; and Pittsburgh, Pennsylvania under the terms of operating leases expiring through January, 2012. 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 \$0.6 million, \$0.4 million and \$0.1 million in 2010, 2011 and 2012, respectively. Total rent expense incurred was \$2.1 million, \$2.1 million and \$1.7 million in 2009, 2008 and 2007, 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 \$1,000 and \$241,000 in 2009 and 2008, respectively, and had no repurchases in 2007.

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 \$18.8 million of new drilling rig components, drill pipe, drill collars and related equipment and \$0.5 million of casing.

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 business segments: contract drilling, oil and natural gas exploration and mid-stream operations, representing our three main business units offering different products and services. The contract drilling segment is engaged in the land contract drilling of oil and natural gas wells, the oil and natural gas exploration 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.

The accounting policies of the segments are the same as those described in the “Summary of Significant Accounting Policies” (Note 2). We evaluate the performance of our business segments based on operating income, which is defined as operating revenues less operating expenses and depreciation, depletion and amortization. We also have some natural gas production in Canada, which is not significant.

	<u>2009</u>	<u>2008</u> (In thousands)	<u>2007</u>
Revenues:			
Contract drilling	\$ 251,364	\$ 688,196	\$ 673,517
Elimination of inter-segment revenue	(15,049)	(65,469)	(45,875)
Contract drilling net of inter-segment revenue	<u>236,315</u>	<u>622,727</u>	<u>627,642</u>
Oil and natural gas exploration	<u>357,879</u>	<u>553,998</u>	<u>391,480</u>
Gas gathering and processing	142,491	237,999	161,679
Elimination of inter-segment revenue	<u>(33,863)</u>	<u>(56,269)</u>	<u>(23,084)</u>
Gas gathering and processing net of inter-segment revenue	<u>108,628</u>	<u>181,730</u>	<u>138,595</u>
Other	7,076	(362)	1,037
Total revenues	<u>\$ 709,898</u>	<u>\$ 1,358,093</u>	<u>\$ 1,158,754</u>
Operating income (loss) (1):			
Contract drilling	\$ 50,909	\$ 239,979	\$ 266,058
Oil and natural gas exploration	(125,777)(5)	(3,757)(4)	166,954
Gas gathering and processing	<u>4,616</u>	<u>16,442</u>	<u>7,760</u>
Total operating income (loss)	<u>(70,252)</u>	<u>252,664</u>	<u>440,772</u>
General and administrative expense	(24,011)	(25,419)	(22,036)
Interest expense, net	(539)	(1,304)	(6,362)
Other income (expense)—net	<u>7,076</u>	<u>(362)</u>	<u>1,037</u>
Income (loss) before income taxes	<u>\$ (87,726)</u>	<u>\$ 225,579</u>	<u>\$ 413,411</u>
Identifiable assets (2):			
Contract drilling	\$ 951,702	\$ 1,009,292	\$ 879,784
Oil and natural gas exploration	1,068,970(5)	1,363,534(4)	1,148,633
Gas gathering and processing	<u>163,625</u>	<u>169,687</u>	<u>148,865</u>
Total identifiable assets	<u>2,184,297</u>	<u>2,542,513</u>	<u>2,177,282</u>
Corporate assets	<u>44,102</u>	<u>39,353</u>	<u>22,537</u>
Total assets	<u>\$ 2,228,399</u>	<u>\$ 2,581,866</u>	<u>\$ 2,199,819</u>
Capital expenditures:			
Contract drilling	\$ 67,686	\$ 196,229	\$ 220,424(3)
Oil and natural gas exploration	230,550	561,548	307,337
Gas gathering and processing	9,899	49,887	34,176
Other	474	9,860	2,190
Total capital expenditures	<u>\$ 308,609</u>	<u>\$ 817,524</u>	<u>\$ 564,127</u>
Depreciation, depletion, amortization and impairment:			
Contract drilling	\$ 45,326	\$ 69,841	\$ 56,804
Oil and natural gas exploration:			
Depreciation, depletion and amortization	114,681	159,550	127,417
Impairment of oil and natural gas properties	281,241(5)	281,966(4)	—
Gas gathering and processing	16,104	14,822	11,059
Other	<u>1,055</u>	<u>699</u>	<u>831</u>
Total depreciation, depletion, amortization and impairment	<u>\$ 458,407</u>	<u>\$ 526,878</u>	<u>\$ 196,111</u>

- (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.
- (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) Includes \$5.3 million of goodwill from the acquisition in June 2007.
- (4) In December 2008, we incurred a \$282.0 million pre-tax (\$175.5 million net of tax) non-cash write down of oil and natural gas properties due to low commodity prices at year-end 2008.
- (5) 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)			
2009:				
Revenues	\$ 201,062	\$ 164,074	\$ 167,430	\$ 177,332
Gross profit (loss) (1)	\$ (232,004)	\$ 55,970	\$ 54,111	\$ 51,671
Net income (loss)	\$ (147,493)	\$ 32,031	\$ 31,449	\$ 28,513
Net income (loss) per common share:				
Basic	\$ (3.14)	\$ 0.68	\$ 0.67	\$ 0.61
Diluted (2)	\$ (3.14)	\$ 0.68	\$ 0.66	\$ 0.60
2008:				
Revenues	\$ 321,362	\$ 370,147	\$ 375,563	\$ 291,021
Gross profit (loss) (1)	\$ 129,778	\$ 156,589	\$ 153,379	\$ (187,082)
Net income (loss)	\$ 77,064	\$ 94,128	\$ 92,281	\$ (119,848)
Net income (loss) per common share:				
Basic (2)	\$ 1.66	\$ 2.02	\$ 1.98	\$ (2.57)
Diluted (2)	\$ 1.65	\$ 2.00	\$ 1.96	\$ (2.57)

- (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.

Note 18. Subsequent Events

In January and February 2010, our contract drilling segment entered into contracts to sell eight of its idle mechanical drilling rigs to an unaffiliated third party. These drilling rigs ranged in horse power from 800 to 1,000. The closing on three of these drilling rigs occurred in February. Three more are scheduled to close during the first quarter of 2010 with the last transaction for the remaining two rigs anticipated to close during the second quarter of 2010. Proceeds from the sale of all the drilling rigs will be \$23.9 million resulting in an estimated gain of \$6.1 million. The proceeds from this sale will be used to refurbish and upgrade additional rigs in our fleet in order that those rigs can 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. At completion of the sale of the eight rigs and with the additional rig recently placed into service, this segment will have 123 drilling rigs in its fleet.

**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:

	<u>2009</u>	<u>2008</u>	<u>2007</u>
	(In thousands)		
Capitalized costs:			
Proved properties	\$ 2,309,193	\$ 2,090,623	\$ 1,624,478
Unproved properties	<u>140,129</u>	<u>160,034</u>	<u>64,722</u>
	2,449,322	2,250,657	1,689,200
Accumulated depreciation, depletion, amortization and impairment	<u>(1,424,559)</u>	<u>(1,029,617)</u>	<u>(589,029)</u>
Net capitalized costs	<u>\$ 1,024,763</u>	<u>\$ 1,221,040</u>	<u>\$ 1,100,171</u>
Cost incurred:			
Unproved properties acquired	\$ 37,137	\$ 113,104	\$ 33,398
Proved properties acquired	3,722	41,227	1,820
Exploration	30,547	41,474	37,673
Development	154,579	351,876	235,203
Asset retirement obligation	4,565	13,867	(757)
Total costs incurred	<u>\$ 230,550</u>	<u>\$ 561,548</u>	<u>\$ 307,337</u>

The following table shows a summary of the oil and natural gas property costs not being amortized at December 31, 2009, by the year in which such costs were incurred:

	<u>2009</u>	<u>2008</u>	<u>2007</u>	<u>2006 and Prior</u>	<u>Total</u>
	(In thousands)				
Undeveloped Leasehold Acquired	\$ 31,007	\$ 71,956	\$ 13,942	\$ 23,224	\$ 140,129

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:

	<u>2009</u>	<u>2008</u>	<u>2007</u>
	(In thousands)		
Revenues	\$ 352,572	\$ 545,937	\$ 386,231
Production costs	(75,214)	(102,207)	(84,382)
Depreciation, depletion, amortization and impairment	<u>(394,942)</u>	<u>(440,588)</u>	<u>(126,719)</u>
	(117,584)	3,142	175,130
Income tax (expense) benefit	<u>43,153</u>	<u>(1,141)</u>	<u>(62,337)</u>
Results of operations for producing activities (excluding corporate overhead and financing costs)	<u>\$ (74,431)</u>	<u>\$ 2,001</u>	<u>\$ 112,793</u>

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:

	<u>Oil Bbls</u>	<u>Liquids Bbls</u>	<u>Natural Gas Mcf</u>
		(In thousands)	
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 ⁽³⁾	<u>11,669</u>	<u>14,653</u>	<u>419,061</u>
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
2008:			
Proved developed and undeveloped reserves:			
Beginning of year	9,676	6,149	419,616
Revision of previous estimates	(1,278)	2,023	(23,431)
Extensions and discoveries	1,511	1,522	60,369
Infill reserves in existing proved fields ⁽²⁾	830	1,657	29,848
Purchases of minerals in place	221	208	11,206
Production	(1,261)	(1,388)	(47,473)
End of Year	<u>9,699</u>	<u>10,171</u>	<u>450,135</u>
Proved developed reserves:			
Beginning of year	7,770	5,133	326,071
End of year	7,508	8,638	355,824
Proved undeveloped reserves:			
Beginning of year	1,906	1,016	93,545
End of year	2,191	1,533	94,311
2007:			
Proved developed and undeveloped reserves:			
Beginning of year	9,357	2,226	406,400
Revision of previous estimates ⁽⁴⁾	(111)	2,830	(16,382)
Extensions and discoveries	1,346	1,228	49,758
Infill reserves in existing proved fields ⁽²⁾	175	650	22,884
Purchases of minerals in place	—	—	420
Production	(1,091)	(785)	(43,464)
End of Year	<u>9,676</u>	<u>6,149</u>	<u>419,616</u>
Proved developed reserves:			
Beginning of year	7,465	2,042	307,734
End of year	7,770	5,133	326,071
Proved undeveloped reserves:			
Beginning of year	1,892	184	98,666
End of year	1,906	1,016	93,545

(1) Natural gas revisions of previous estimates decreased primarily due to a decline in natural gas prices as well as deleting PUDs that were stale or uneconomical.

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

(3) Reflects the effects of new oil and gas reserve measurement requirements. Reserve quantities at December 31, 2009 under the previous reporting rules are 12,066 Bbls, 15,106 Bbls and 438,551 Mcf for oil, liquids and natural gas, respectively.

(4) As a result of processing more natural gas liquids out of our natural gas, revisions of previous estimates reflect an increase in NGLs derived from natural gas.

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:

	<u>2009</u>	<u>2008</u>	<u>2007</u>
	(In thousands)		
Future cash flows	\$ 2,403,892	\$ 2,694,217	\$ 3,890,789
Future production costs	(777,725)	(769,325)	(1,007,681)
Future development costs	(195,486)	(253,941)	(234,415)
Future income tax expenses	(433,366)	(510,361)	(880,560)
Future net cash flows	<u>997,315</u>	<u>1,160,590</u>	<u>1,768,133</u>
10% annual discount for estimated timing of cash flows	(450,980)	(536,116)	(777,802)
Standardized measure of discounted future net cash flows relating to proved oil, NGLs and natural gas reserves	<u>\$ 546,335</u>	<u>\$ 624,474</u>	<u>\$ 990,331</u>

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

	<u>2009</u>	<u>2008</u>	<u>2007</u>
	(In thousands)		
Sales and transfers of oil and natural gas produced, net of production costs	\$ (277,358)	\$ (443,729)	\$ (301,847)
Net changes in prices and production costs	(145,839)	(548,683)	344,497
Revisions in quantity estimates and changes in production timing	(54,327)	(34,066)	(155)
Extensions, discoveries and improved recovery, less related costs	136,695	229,928	311,529
Changes in estimated future development costs	100,304	20,273	19,971
Previously estimated cost incurred during the period	16,301	55,763	49,333
Purchases of minerals in place	1,288	20,797	1,540
Sales of minerals in place	—	—	—
Accretion of discount	89,256	148,160	98,412
Net change in income taxes	39,062	223,188	(192,045)
Other—net	16,479	(37,488)	(25,799)
Net change	<u>(78,139)</u>	<u>(365,857)</u>	<u>305,436</u>
Beginning of year	624,474	990,331	684,895
End of year	<u>\$ 546,335</u>	<u>\$ 624,474</u>	<u>\$ 990,331</u>

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

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

Effective December 31, 2009, future cash flows are computed by applying the unescalated 12-month average prices of \$61.18 per barrel for oil, \$34.44 per barrel for NGLs and \$3.86 per Mcf for natural gas relating to proved reserves and to the year-end quantities of those reserves. Previously, 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.

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, 2009.

The effectiveness of the company's internal control over financial reporting as of December 31, 2009, 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.

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 5, 2010.

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 18, 2009. 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 12, 2010 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.

<u>NAME</u>	<u>AGE</u>	<u>POSITION HELD</u>
Larry D. Pinkston	55	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	52	Senior Vice President since December 2002, General Counsel and Corporate Secretary since January 1987
David T. Merrill	49	Chief Financial Officer and Treasurer since February 24, 2004, Vice President of Finance from August 2003 to February 24, 2004
Brad J. Guidry	54	Executive Vice President, Unit Petroleum Company since March 1, 2005
John Cromling	62	Executive Vice President, Unit Drilling Company since April 15, 2005
Robert Parks	55	A Manager and President, Superior Pipeline Company, L.L.C. since June 1996
Richard E. Heck	49	Vice President, Safety, Health and Environment since January 2008

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

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.

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, 2009, under which our equity securities were authorized for issuance:

<u>Plan Category</u>	<u>Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)</u>	<u>Weighted Average Exercise Price of Outstanding Options, Warrants and Rights (b)</u>	<u>Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (c)</u>
Equity compensation plans approved by security holders(1)	356,221 (2) \$	37.36	1,667,754 (3)
Equity compensation plans not approved by security holders	24,504(4)	33.51	275,496(4)
Total	<u>380,725</u>	<u>\$ 37.11</u>	<u>1,943,250</u>

- (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:
- 212,725 stock options outstanding under the company's Amended and Restated Stock Option Plan.
143,496 stock options outstanding under the Non-Employee Directors' Stock Option Plan.
- (3) This number reflects 4 shares available for issuance under the Non-Employee Directors' Stock Option Plan and 1,667,750 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.
- (4) On May 29, 2009, Unit Corporation through its compensation committee and board of directors, approved amendments to the existing 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 by 300,000. Also on May 29, 2009 a one-time grant of 3,063 shares were made to each non-employee director, the contingent option awards. These awards cannot vest before the stockholder's approve this amended plan, and will be void in the event such approval is not obtained.

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, 2009 and 2008
Consolidated Statements of Operations for the years ended December 31, 2009, 2008 and 2007
Consolidated Statements of Changes in Shareholders' Equity for the years ended December 31, 2007, 2008 and 2009
Consolidated Statements of Cash Flows for the years ended December 31, 2009, 2008 and 2007
Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

Included in Part IV of this report for the years ended December 31, 2009, 2008 and 2007:

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).
- 4.2.1 Form of Common Stock Certificate (filed as Exhibit 4.1 on Form S-3 as S.E.C. File No. 333-83551, which is incorporated herein by reference).
- 4.2.2 Rights Agreement as amended and restated on May 24, 2009 (filed as Exhibit 4.1 to Unit's Form 8-K dated March 23, 2009, which is incorporated herein by reference).
- 4.2.3 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).

- 4.3 Indenture (filed as Exhibit 4.3 to Unit's Form S-3 filed with the S.E.C. File No. 333-104165, 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, 2009 (filed as Exhibit 10.2 to Unit's Form 8-K dated May 29, 2009, which is incorporated herein by reference).
- 10.1.5 First Amended and Restated Senior Credit Agreement dated May 24, 2007 (filed as Exhibit 10.1 to Unit's Form 8-K dated May 25, 2007, which is incorporated herein by reference).
- 10.1.6 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).
- 10.1.7 Amendment to First Amended and Restated Senior Credit Agreement dated December 23, 2008 (filed as Exhibit 10.1 to Unit's Form 8-K dated December 23, 2008, 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, which is incorporated herein by reference).
- 10.2.5* Unit Corporation Employees' Thrift Plan (filed as an Exhibit to Form S-8 as S.E.C. File No. 33-53542, which is incorporated herein by reference).
- 10.2.6 Unit Consolidated Employee Oil and Gas Limited Partnership Agreement (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 1993, which is incorporated herein by reference).
- 10.2.7* Unit Corporation Salary Deferral Plan (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 1993, which is incorporated herein by reference).
- 10.2.8* Separation Agreement, dated May 11, 2001, between the Registrant and Mr. Kirchner (filed as Exhibit 99.4 to Unit's Form 8-K dated May 18, 2001, which is incorporated herein by reference).
- 10.2.9* Consulting Agreement, dated December 16, 2004, between John G. Nikkel and the Registrant (filed as Exhibit 10.4 to Unit's Form 8-K dated December 20, 2004).
- 10.2.10* 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).

- 10.2.11* Unit Corporation Special Separation Benefit Plan as amended (filed as Exhibit 10.3 to Unit's Form 8-K dated December 20, 2004).
- 10.2.12* Consulting Agreement Renewal dated April 12, 2006, between John G. Nikkel and the Registrant (filed as Exhibit 99.1 to Unit's Form 8-K dated April 18, 2006).
- 10.2.13 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).
- 10.2.14* 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).
- 10.2.15 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).
- 10.2.16 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).
- 10.2.17 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).
- 10.2.18 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).
- 10.2.19 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).
- 10.2.20* 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).
- 10.2.21 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).
- 10.2.22 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).
- 10.2.23 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).
- 10.2.24 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).
- 10.2.25 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).
- 10.2.26 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).
- 10.2.27 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).
- 10.2.28 Special Separation Benefit Plan as amended December 31, 2008 (filed as Exhibit 10.2 to Unit's Form 8-K dated January 6, 2009, which is incorporated herein by reference).

- 10.2.29 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).
 - 10.2.30 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).
 - 10.2.31 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).
 - 10.2.32 Unit 2010 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed herein).
 - 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).
- * Indicates a management contract or compensatory plan identified under the requirements of Item 15 of Form 10-K.

Schedule II

UNIT CORPORATION AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Allowance for Doubtful Accounts:

<u>Description</u>	<u>Balance at Beginning of Period</u>	<u>Additions Charged to Costs & Expenses</u>	<u>Deductions & Net Write-Offs</u>	<u>Balance at End of Period</u>
	(In thousands)			
Year ended December 31, 2009	\$ 4,893	\$ 975	\$ (682)	\$ 5,186
Year ended December 31, 2008	\$ 3,350	\$ 1,620	\$ (77)	\$ 4,893
Year ended December 31, 2007	\$ 1,600	\$ 1,750	\$ —	\$ 3,350

EXHIBIT INDEX

Exhibit No.	Description
10.2.32	Unit 2010 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership.
21	Subsidiaries of the Registrant.
23.1	Consent of Independent Registered Public Accounting Firm, PricewaterhouseCoopers LLP.
23.2	Consent of Ryder Scott Company, L.P.
31.1	Certification of Chief Executive Officer under Rule 13a—14(a) of the Exchange Act.
31.2	Certification of Chief Financial Officer under Rule 13a—14(a) of the Exchange Act.
32	Certification of Chief Executive Officer and Chief Financial Officer under Rule 13a-14(a) of the Exchange Act and 18 U.S.C. Section 1350, as adopted under Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Ryder Scott Company, L.P. Summary Report.