UNIT CORP
Form 10-K
February 24, 2009
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE

SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2008

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE

SECURITIES EXCHANGE ACT OF 1934

For the transition period from __________ to__________

Commission file number: 1-9260

UNIT CORPORATION

(Exact name of registrant as specified in its charter)

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

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

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

Title of each class	**Name of each exchange on which registered**
Common Stock, par value $.20 per share	NYSE

Rights to Purchase Series A Participating Cumulative Preferred Stock	NYSE

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes x No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.

Yes ¨ No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes x No ¨

Indicate by check mark 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 x Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ¨ No x

As of June 30, 2008, the aggregate market value of the voting and non-voting common equity (based on the closing price of the stock on the New York Stock Exchange on June 30, 2008) held by non-affiliates was approximately $2,759,469,527. Determination of stock ownership by non-affiliates was made solely for the purpose of this requirement, and the registrant is not bound by these determinations for any other purpose.

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

Class	Outstanding at February 13, 2009
Common Stock, $0.20 par value per share	47,299,192 shares

DOCUMENTS INCORPORATED BY REFERENCE

Document	Parts Into Which Incorporated
Portions of the registrant s Definitive Proxy Statement (the Proxy Statement) with respect to its annual meeting of shareholders scheduled to be held on May 6, 2009.	Part III

Exhibit Index See Page 108

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UNIT CORPORATION

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DEFINITIONS

The following are explanations of some of the terms used in this report.

ARO Asset retirement obligations.

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.

NGPL-TXOK Natural Gas Pipeline Co. of America/Texok zone.

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DEFINITIONS (Continued)

NYMEX The New York Mercantile Exchange.

OPIS Oil Price Information Service.

PEPL Panhandle East Pipeline Co.

Producing property A natural gas and oil property with existing production.

Proved developed reserves Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. For additional information, see the SEC s definition in Rule 4-10(a)(3) of Regulation S-X.

Proved reserves The estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. 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. Reserves on undrilled acreage are limited to those drilling units that offset productive units and that are reasonably certain of production when drilled. For additional information, see the SEC s definition in Rule 4-10(a)(4) of Regulation S-X.

SARs Stock appreciation rights.

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.

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UNIT CORPORATION

Annual Report

For The Year Ended December 31, 2008

PART I

Item 1. Business

Unless otherwise indicated or required by the context, the terms corporation , company , Unit , us , our , we and its refer to Unit Corporat appropriate, 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, Canadian, Houston and Weatherford, Texas; Englewood and Denver, Colorado; Casper and Pinedale, Wyoming; and Pittsburg, 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 the various corporate governance documents that we have adopted. 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. Information regarding 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.

GENERAL

We were founded in 1963 as a contract drilling company. Today, our operations are generally conducted through our three principal wholly owned subsidiaries:

- Unit Drilling Company which drills onshore oil and natural gas wells for our own account and for others (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 our own account and for third parties (mid-stream).

At various times, and from time to time, 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 13, 2009:

Number of drilling rigs owned	132
Completed gross wells in which we own an interest	7,818
Number of natural gas treatment plants owned	3
Number of processing plants owned	9
Number of natural gas gathering systems owned	37

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NOTABLE EVENTS

Certain notable events by us in 2008 include:

Contract Drilling

- Constructed and placed into service three new 1,500 horsepower diesel electric drilling rigs, bringing the rig fleet to a total of 132 rigs.
- Drilled total footage of 11.7 million feet, the most in company history.

Oil and Natural Gas

- For the 25th consecutive year the segment replaced more than 150% of its annual production with new oil, NGLs and natural gas reserves by replacing approximately 186% of its 2008 oil, NGLs and natural gas production.
- Attained net proved oil, NGLs and natural gas reserves of 569.4 Bcfe, an 11% increase over its proved oil, NGLs and natural gas reserves at the end of 2007.
- Produced a company record 63.4 Bcfe, a 16% increase over 2007.

Mid-Stream

- Completed the installation of one natural gas processing plant, increasing processing capacity by approximately 20 MMcf per day.
- Added two new gathering systems.
- Added an additional 94 miles of pipeline, which is an approximate 14% increase and connected an additional 99 new wells to its gathering systems.

FINANCIAL INFORMATION ABOUT SEGMENTS

See Note 15 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 the Oklahoma and Texas areas of the Anadarko and Arkoma Basins, the North Texas Barnett Shale, the Texas and Louisiana Gulf Coast, East Texas and the Rocky Mountain regions of Wyoming, Colorado, Utah and North Dakota.

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

	Year Ended December 31,		
	2008	**2007**	**2006**
Number of drilling rigs owned at end of period	132.0	129.0	117.0
Average number of drilling rigs owned during period	130.4	123.8	114.0
Average number of drilling rigs utilized	103.1	99.4	109.0
Utilization rate (1)	79%	80%	96%
Average revenue per day (2)	$ 16,498	$ 17,291	$ 17,574
Total footage drilled (feet in 1,000 s)	11,734	10,453	11,461
Number of wells drilled	1,028	996	1,033

(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.

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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 2008, 122 of our 132 drilling rigs performed contract drilling services.

The following table shows certain information about our drilling rigs (including their distribution) as of February 13, 2009:

Region	Contracted Rigs	Non-Contracted Rigs	Total Rigs	Average Rated Drilling Depth (ft)
Anadarko Basin Oklahoma	16	11	27	18,056
Panhandle of Texas	9	32	41	14,695
Arkoma Basin	5	10	15	15,100
East Texas, Gulf Coast and North Texas Barnett Shale	12	11	23	15,783
Rocky Mountains	13	13	26	17,692
Totals	55	77	132	16,208

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 2008, our Anadarko, Mid-Continent and Woodward divisions marketed 48 drilling rigs in the Anadarko Basin. These three divisions averaged 14, 16 and 11 drilling rigs operating during 2008, respectively.

Panhandle of Texas. During 2008, we marketed 23 drilling rigs through our Panhandle and Pampa divisions. 18 drilling rigs operated during the year in these two divisions. We are the largest drilling contractor in the combined Anadarko Basin of Oklahoma and the Texas Panhandle.

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 is home to multiple conventional gas plays as well as two of the more recent notable unconventional plays the Woodford Shale and Fayetteville Shale.

During 2008, Our Arkoma division marketed 12 drilling rigs with an average of over 10 drilling rigs operating during the year. The Woodford Shale brought an increase in activity to the Arkoma division operations. Additionally, our oil and natural gas segment s active presence in the Arkoma Basin has been a source of work for our drilling fleet.

East Texas, Gulf Coast and 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. Our Gulf Coast division marketed 17 drilling rigs during 2008, with an average of over 13 drilling rigs operating. The increased interest in the Houston/Haynesville Shale play provided opportunity to reposition drilling rigs into this active market area.

North Central Texas is the home of the Barnett Shale. 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 through multi-stage high pressure fracturization completion processes of this tight gas bearing formation.

During 2008, our North Texas division marketed 6 drilling rigs and operated 3 drilling rigs during the year.

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 numbers 26 drilling rigs with an average of 18 drilling rigs operating during 2008. We have a number of 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. Two drilling rigs made our first entry into the Bakken Shale in North Dakota during the year.

At present, we do not have a shortage of drilling rig related equipment. However, at any given time, our ability to use all of our drilling rigs is dependent on a number of conditions, including the availability of qualified labor, drilling supplies and equipment as well as demand. In 2006, demand for our drilling rigs increased and our utilization rate remained above 92%. 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%, however by December 2008, our average utilization rate had declined to 61% The decline in drilling rig utilization has reduced the competition for labor that previously existed within the drilling industry which in turn has 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:

	2008	2007	2006
First quarter	100.6	96.8	108.6
Second quarter	104.5	97.9	110.3
Third quarter	110.7	100.3	110.6
Fourth quarter	96.7	102.7	106.7

Drilling Rig Fleet. The following table summarizes the changes made to our drilling rig fleet during 2008. A more complete discussion of these changes follows the table:

Drilling rigs owned at December 31, 2007	129
Drilling rigs purchased during 2008	
Drilling rigs constructed during 2008	3
Total drilling rigs owned at December 31, 2008	132

Acquisitions and Construction. In June 2007, we acquired a privately owned drilling company operating primarily in the Texas Panhandle. This acquisition included nine drilling rigs ranging from 800 to 1,000 horsepower. Eight of the nine drilling rigs were operational immediately after the purchase; the last drilling rig was refurbished and became operational during March of 2008. During the first six months of 2007, we completed the construction of two 1,500 horsepower drilling rigs for approximately $19.4 million and placed one of them into each of our Rocky Mountain and Anadarko divisions. In the fourth quarter of 2007, we completed the construction of a third 1,500 horsepower drilling rig for an estimated $12.0 million which was also moved into our Rocky Mountain division.

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

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horsepower diesel electric drilling rig for approximately $14.1 million and placed this drilling rig into service in North Dakota. The addition of these drilling rigs brought our drilling rig fleet to 132 at December 31, 2008.

In late 2008, as a result of the significant decline in commodity prices and the resulting drop in demand for our drilling rigs, we stored a 1,500 horsepower diesel electric drilling rig in our Oklahoma City rig fabrication facility and yard that was scheduled to be placed into service in North Dakota during the first quarter of 2009. The mobilization has been delayed pending final negotiation with our customer. In addition, after discussions with our customers, we postponed the construction of eight additional drilling rigs we had previously anticipated building and instead substituted drilling rigs we already owned. As a result of existing contractual obligations, we expect to take delivery of a new drilling rig during the fourth quarter of 2009.

As part of the proposed new rig construction program, 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.

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. To date, we have not experienced significant losses in performing turnkey contracts. In 2008, 2007 and 2006, we did not drill any turnkey wells. All of our work in 2008 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. Of the term contracts, they range from six months to three years in length of term. Depending on the contract, the rates can either be fixed throughout the term or allow for adjustment at periodic intervals.

Customers. During 2008, Questar Corporation was our largest drilling customer providing approximately 19% of our total contract drilling revenues. No other third party customer accounted for 10% or more of our contract drilling revenues. During 2008, 2007 and 2006, we drilled 122, 77 and 72 wells, respectively, for our oil and natural gas segment. As required by the SEC, the profit received by our contract drilling segment when we drill wells for our oil and natural gas segment reduced the carrying value of our oil and natural gas properties by $27.9 million, $22.7 million and $22.2 million during 2008, 2007 and 2006, respectively, rather than being included in our operating profit.

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OIL AND NATURAL GAS

General. In 1979, we began to develop our exploration and production operations to diversify our contract drilling revenues. 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.

The following table presents certain information regarding our oil and natural gas operations as of December 31, 2008:

			2008 Average Net Daily Production		
Property/Area	**Number of Gross Wells**	**Number of Net Wells**	**Natural Gas (Mcf)**	**Oil (Bbls)**	**NGL (Bbls)**
Western division (consists principally of the Rocky Mountain region, New Mexico, Western and Southern Texas and the Gulf Coast region)	3,220	519.35	39,767	1,787	1,990
East division (consists principally of the Appalachian region, Arkansas, East Texas, Northern Louisiana and Eastern Oklahoma)	1,084	257.36	43,860	37	13
Central division (consists principally of Kansas, Western Oklahoma and the Texas Panhandle)	3,524	867.06	46,082	1,620	1,790
Total	7,828	1,643.77	129,709	3,444	3,793

When we are the operator of a property, we generally attempt to use a drilling rig owned by our contract drilling segment.

In response to the recent industry events we elected to close our Midland office in January 2009.

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Acquisitions. On October 13, 2006, we completed the acquisition of Brighton Energy, L.L.C., a privately owned oil and natural gas company. On February 1, 2008, Brighton Energy, L.L.C. was merged with and into Unit Petroleum Company.

Our oil and natural gas segment did not make any significant acquisitions during 2007.

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, we acquired interest in approximately 55,000 undeveloped acres in the Marcellus Shale, located mainly in Pennsylvania for approximately $40.1 million.

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,					
	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Wells drilled:						
Exploratory:						
Oil	3	1.45	2	0.50		
Natural gas	5	4.18	6	4.43	5	2.39
Dry	7	2.60	5	2.32	5	2.24
	15	8.23	13	7.25	10	4.63
Development:						
Oil	55	26.62	15	5.45	12	2.62
Natural gas	182	85.49	197	69.30	199	67.93
Dry	26	13.97	28	14.64	23	10.12
	263	126.08	240	89.39	234	80.67
Total	278	134.31	253	96.64	244	85.30

	Year Ended December 31,					
	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Oil and natural gas wells producing or capable of producing:						
Oil	2,665	418.27	2,612	392.99	2,784	492.90
Natural gas	5,015	1,151.84	4,855	1,077.38	4,659	1,007.83
Total	7,680	1,570.11	7,467	1,470.37	7,443	1,500.73

As of February 13, 2009, we had participated in 13 gross (3.03 net) wells started during 2009.

Cost incurred for development drilling includes $89.4 million, $52.7 million and $34.3 million in 2008, 2007 and 2006, respectively, to develop booked proved undeveloped oil and natural gas reserves.

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

	Year Ended December 31,					
	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Developed acreage	1,042,602	314,519	1,022,788	299,734	1,019,898	292,870
Undeveloped acreage	809,977	316,147(1)	441,726	227,589	371,314	182,742

(1) Approximately 73% of the net undeveloped acres are covered by leases that will expire in the years 2009 2011 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 2009, 2010 and 2011, as disclosed in our December 31, 2008 oil and natural gas reserve report, are $66.5 million, $133.3 million and $27.6 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,		
	2008	2007	2006
Average sales price per barrel of oil produced:			
Price before hedging	$ 98.02	$ 70.61	$ 63.39
Effect of hedging	(4.15)		
Price including hedging	$ 93.87	$ 70.61	$ 63.39
Average sales price per barrel of NGLs produced:			
Price before hedging	$ 47.38	$ 45.01	$ 36.08
Effect of hedging	.04	.02	
Price including hedging	$ 47.42	$ 45.03	$ 36.08
Average sales price per Mcf of natural gas produced:			
Price before hedging	$ 7.53	$ 6.24	$ 6.17
Effect of hedging	.09	0.06	
Price including hedging	$ 7.62	$ 6.30	$ 6.17
Oil production (MBbls)	1,261	1,091	1,012
NGL production (MBbls)	1,388	785	441
Natural gas production (MMcf)	47,473	43,464	44,169
Total production (MMcfe)	63,368	54,720	52,889
Average production cost per equivalent Mcf	$ 1.86	$ 1.69	$ 1.34

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,		
	2008	2007	2006
Oil (MBbls)	9,699	9,676	9,357
Natural gas liquids (MBbls)	10,171	6,149	2,226
Natural gas (MMcf)	450,135	419,616	406,400
Total proved reserves (MMcfe)	569,353	514,569	475,899

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 2008, 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 2008, our mid-stream segment purchased $52.0 million of our natural gas production and natural gas liquids and provided gathering and transportation services of $4.3 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 2007 and 2006, we eliminated intercompany revenues of $23.1 million and $13.3 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, nine operating processing plants, 37 active gathering systems and 770 miles of pipeline. Superior and its subsidiary operate in Oklahoma, Texas, Louisiana, Kansas and Pennsylvania.

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

	Year Ended December 31,		
	2008	2007	2006
Gas gathered MMBtu/day	197,367	219,635	247,537
Gas processed MMBtu/day	67,796	50,350	31,833
Natural gas liquids sold gallons/day	195,837	129,421	66,902

Acquisitions. In September 2006, we closed the acquisition of Berkshire Energy, LLC, a private company for an adjusted purchase price of $21.7 million. The principal tangible assets of the acquired company consisted of a natural gas processing plant, a natural gas gathering system with 15 miles of pipeline, three field compressors and two plant compressors. This purchase had an effective date of July 31, 2006. The financial results of this acquisition are included in the company s statement of income from September 1, 2006 forward with the results for the period of August 1, 2006 through August 31, 2006 included as an adjustment to the purchase price.

Our mid-stream segment did not have any significant acquisitions during 2007 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, 2008, 66% of our mid-stream segment s total volumes and 20% 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

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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, 2008, 18% of our mid-stream segment s total volumes and 33% 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, 2008, 16% of our mid-stream segment s total volumes and 47% 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 2008, ONEOK accounted for approximately 79% of our mid-stream revenues; however, we believe there are other customers available to purchase our gas and liquids should it become necessary.

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 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, for each of the periods indicated:

	Natural Gas Price per Mcf		Oil Price per Bbl		NGL Price per Bbl	
Quarter	**High**	**Low**	**High**	**Low**	**High**	**Low**
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
2006:						
Fourth	$ 6.72	$ 4.50	$ 58.23	$ 56.15	$ 36.25	$ 31.37
Third	$ 6.74	$ 5.55	$ 72.49	$ 61.56	$ 41.08	$ 38.30
Second	$ 6.06	$ 5.46	$ 69.67	$ 67.26	$ 33.48	$ 30.03
First	$ 7.99	$ 6.13	$ 62.39	$ 57.58	$ 46.96	$ 35.41

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;

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- 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 increased over the first three quarters of 2006, before declining late in the fourth quarter of 2006 and throughout 2007. This was followed by a resurgence in activity during the first nine months of 2008, before a decline in activity during the fourth quarter 2008. Our average dayrate and utilization rate were as follows for the month of December for each of the following years:

	2008	2007	2006
Dayrate	$ 19,352	$ 17,945	$ 19,930
Utilization	61%	79%	88%
Rigs owned at December 31,	132	129	117

The decrease in utilization starting in the fourth quarter of 2006 and again during the fourth quarter of 2008 was, in part, due to the decline in the price of natural gas as well as concerns regarding future demand for natural gas on the part of our customers. Since short-term and long-term trends in oil and natural gas prices affect the demand for our drilling rigs, the future demand for and the dayrates we will receive for our drilling services is expected to decline further given the unsettled outlook for future commodity prices.

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.

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COMPETITION

All of our businesses are highly competitive and price sensitive. Competition in the land contract drilling business traditionally involves factors such as demand, price, efficiency, condition of equipment, availability of labor and equipment, reputation and customer relations. A few of our contract drilling competitors are substantially larger than we are and have greater resources.

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 2006, 2007 and through the first nine months of 2008 all of our operations experienced strong competition for qualified labor. However, if the recent depressed conditions within our industry continue, we do not anticipate that competition to keep qualified employees and attract individuals with the skills required to meet our immediate requirements will materially effect us. Likewise, if current commodity price and industry drilling utilization declines continue, we do not anticipate that our drilling labor costs will increase from those levels in effect at the beginning of the fourth quarter of 2008.

OIL AND NATURAL GAS PROGRAMS AND CONFLICTS OF INTEREST

Unit Petroleum Company serves as the general partner of 14 oil and gas limited partnerships. Three of these partnerships were formed for investment by third parties and 11 (the employee partnerships) were formed to allow our employees and directors 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 9 to the Consolidated Financial Statements in Item 8 of this report.

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EMPLOYEES

As of February 13, 2009, we had approximately 1,643 employees in our contract drilling operations, 217 employees in our oil and natural gas operations, 88 employees in our mid-stream operations and 62 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.

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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.

Environmental laws and regulations are complex and subject to frequent change that may result in more stringent and costly requirements. Compliance with applicable requirements has not, to date, had a material affect on the cost of our operations, earnings or competitive position. However, compliance with amended, new or more stringent requirements, stricter interpretations of existing requirements, or the discovery of contamination 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;

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- 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 2009 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.

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As noted elsewhere in this report, the recent economic decline and commodity price decline have significantly reduced the demand for our drilling rigs. If these conditions continue, we expect that the demand for our drilling rigs will continue to stay depressed, if not reduced further.

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 2008 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 $371,000 per month ($4.5 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 $99,000 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 $109,000 per month ($1.3 million annualized) change in our pre-tax operating cash flow. During 2008, substantially all of our natural gas, crude oil and NGLs volumes were sold at market responsive 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 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;

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- 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. As required by the SEC, the estimated discounted future net cash flows from proved oil, NGLs and natural gas reserves are determined based on prices and costs as of the date of the estimate. 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%. Application of this ceiling test generally requires pricing future revenue at the unescalated prices in effect as of the end of each fiscal quarter 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. 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.

Based on December 31, 2008 unescalated prices of $44.60 per barrel of oil, $26.04 per barrel of NGLs and $5.71 per Mcf of natural gas, adjusted for regional price differentials, for the estimated life of the respective properties, the unamortized cost of our oil and natural gas properties exceeded the ceiling of our proved oil, NGL and natural gas reserves. 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 these declines in commodity prices. 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. After December 31, 2008 commodity prices have continued to decrease and should commodity prices remain below December 31, 2008 levels, an additional write-down of the carrying value of our oil and natural gas properties will be required for the quarter ending 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

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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, 2008, our outstanding long-term debt was $199.5 million.

Our level of debt, the cash flow needed to satisfy our debt and the covenants contained in our bank credit facility 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, is, to a large extent, a function of the costs associated with the projects we undertake at any given time and of our cash flow. Generally, our normal operating costs are those incurred as a result of 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 items, are discretionary and we maintain a degree of control regarding the timing or the need to actually incur them. However, 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 increased 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. A more thorough discussion of our hedging or swap arrangements are contained in Management s Discussion and Analysis of Financial Condition and Results of Operation section of this report contained in Item 7.

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

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RISK FACTORS

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

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

As a result of recent volatility in oil and natural gas prices and substantial uncertainty in the capital markets due to the deteriorating 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 current deterioration in the global economic environment is resulting 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. 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. Over the past several years demand for natural gas has increased greatly limiting the number of wells being shut-in for lack of demand. 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.

Recent 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.

Widely-documented commercial-credit market disruptions have resulted in a tightening of credit markets in the United States. Liquidity in the global-credit markets have 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

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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. Recent decreases in oil, NGLs and natural gas prices have depressed the level of exploration and production activity. This, in turn, has resulted in a decline in the demand for our drilling services and has had an adverse effect on our contract drilling revenues, cash flows and profitability. As a result, the future demand for our drilling services is uncertain.

Due to declining commodity prices of oil and natural gas, several of our drilling rig customers have significantly reduced their drilling budgets for 2009, resulting in a significant reduction in the average utilization of our drilling rig fleet. Our average utilization rate was 81% for the nine months ended September 30, 2008, 61% for the month of December 2008 and 48% for the month of January 2009. We currently expect this rate to continue to decline in 2009.

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.

Over the past several years, we have increased 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 to you.

We have experienced and may continue to experience substantial working capital needs in the growth of our operations. On February 13, 2009, our outstanding long-term debt was $193.5 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.

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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 and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by the following factors:

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

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

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

We periodically review the carrying value of our oil and natural gas properties under the full cost accounting rules of the SEC. Under these rules, capitalized costs of proved oil and natural gas properties may not exceed the present value of estimated future net revenues from proved reserves, discounted at 10% per year. Application of the ceiling test generally requires pricing future revenue at the unescalated prices in effect as of the end of each fiscal quarter 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. 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.

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 and should commodity prices remain below December 31, 2008 levels, an additional write-down of the carrying value of our oil and natural gas properties will be required for the quarter ending March 31, 2009.

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

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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, 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 also 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 newly elected 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 global warming, 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 we carry, which in turn could have a material adverse effect on our results of operations, financial condition, and liquidity. Government incentives

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encouraging the use of alternative sources of energy could also affect certain of our customers and the markets for certain of the commodities we carry in an unpredictable manner that could alter our traffic patterns, including, for example, the impacts of ethanol incentives on farming and ethanol producers. 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 traffic we handle 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 2008, our largest customer, Questar Corporation accounted for approximately 19% 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 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 recent 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.

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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***

We are a party to various legal proceedings arising in the ordinary course of our business, 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.

Item 4. ***Submission of Matters to a Vote of Security Holders***

No matters were submitted to our security holders during the fourth quarter of 2008.

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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:

	2008		2007	
Quarter	**High**	**Low**	**High**	**Low**
First	$ 56.95	$ 44.00	$ 52.12	$ 44.27
Second	$ 84.70	$ 55.31	$ 65.65	$ 50.45
Third	$ 88.23	$ 45.20	$ 63.00	$ 45.60
Fourth	$ 49.43	$ 21.62	$ 50.41	$ 43.30

On February 13, 2008, the closing sale price of our common stock, as reported by the NYSE, was $26.27 per share. On that date, there were approximately 1,289 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.

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 2008, 2007 and 2006 activity.

	As of and for the Year Ended December 31,				
	2008	**2007**	**2006**	**2005**	**2004**
	(In thousands except per share amounts)				
Revenues	$ 1,358,093	$ 1,158,754	$ 1,162,385	$ 885,608	$ 519,203
Net income	$ 143,625	$ 266,258	$ 312,177	$ 212,442	$ 90,275
Net income per common share:					
Basic	$ 3.08	$ 5.74	$ 6.75	$ 4.62	$ 1.97
Diluted	$ 3.06	$ 5.71	$ 6.72	$ 4.60	$ 1.97
Total assets	$ 2,581,866	$ 2,199,819	$ 1,874,096	$ 1,456,195	$ 1,023,136
Long-term debt	$ 199,500	$ 120,600	$ 174,300	$ 145,000	$ 95,500
Other long-term liabilities	$ 75,807	$ 59,115	$ 55,741	$ 41,981	$ 37,725
Cash dividends per common share	$	$	$	$	$

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Item 7. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***
Please read the following discussion of our financial condition and results of operations in conjunction with the consolidated financial statements and related notes included in Item 8 of this report.

General

We were founded in 1963 as a contract drilling company. Today, we operate, manage and analyze our results of operations through our three principal business segments:

Contract Drilling carried out by our subsidiary Unit Drilling Company and its subsidiaries. This segment contracts to drill onshore oil and natural gas wells for our own account and for others.

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.

Gas Gathering and Processing (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 our own account and for third parties.

Business Outlook

As discussed in other parts of this report, the success of our business and each of our three main operating segments depend, on a large part, on the prices we receive for our natural gas 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 our operations are located within the United States, events outside the United States can also impact us and our industry.

Recent events, both within the United States and the world, have brought about significant and immediate changes in the global financial markets which in turn are affecting the United States economy, our industry and us. In the United States, these events and others have had a significant impact on the prices for oil and natural gas as reflected in the following table:

Date	Gas Spot Price Henry Hub ($ per MMBtu)	Crude Oil WTI-Cushing, OK ($ per Bbl)
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

As noted in the table, oil and natural gas prices have declined significantly during recent months in a deteriorating national and global economic environment. The current economic environment and the recent decline in commodity prices is causing us (and other oil and gas companies) to reduce our overall level of drilling activity and spending. When drilling activity and spending decline for any sustained period of time our dayrates and utilization rates also tend to decline. In addition, lower commodity prices for any sustained period of time could impact the liquidity condition of some of our industry partners and customers, which, in turn, might limit their ability to meet their financial obligations to us.

The recent slowdown in the United States and world economies will also result (to varying degrees) in a reduction in the demand for oil and natural gas products by those industries and consumers that use those

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products in their business operations. The degree to which that demand is reduced and for how long it may last are unknown at this time. Significant reductions in demand for our commodities would result in lower prices for our products as well as forcing us to curtail our production of those products and impact our rig utilization which, in turn, would affect our financial results.

The impact on our business and financial results as a consequence of the recent volatility in oil and natural gas prices and the global economic crisis is uncertain in the long term, but in the short term, it has had a number of consequences for us, including the following:

- 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. After December 31, 2008 commodity prices have continued to decrease and should commodity prices remain below December 31, 2008 levels, an additional write-down of the carrying value of our oil and natural gas properties will be required for the quarter ending March 31, 2009.

- As a result of lower commodity prices combined with service costs that remain relatively high, we have reduced the number of gross wells we plan to drill in 2009 by approximately 37% from the number of gross wells drilled in 2008.

- In late 2008, as a result of the significant decline in commodity prices and the resulting drop in demand for our drilling rigs, we stored a 1,500 horsepower diesel electric drilling rig that was scheduled to be placed into service in North Dakota during the first quarter of 2009. The mobilization has been delayed pending final negotiation with our customer. In addition, after discussions with our customers, we postponed the construction of eight additional drilling rigs we had previously anticipated building and instead substituted drilling rigs we already owned. As a result of existing contractual obligations, we expect to take delivery of a new drilling rig during the fourth quarter of 2009.

- Due to declining commodity prices of oil and natural gas, several of our drilling rig customers have significantly reduced their drilling budgets for 2009, resulting in a significant reduction in the average utilization of our drilling rig fleet. Our average utilization rate was 81% for the nine months ended September 30, 2008, 61% for the month of December 2008 and 48% for the month of January 2009. We currently expect this rate to continue to decline in 2009.

- We have reduced our total 2009 estimated capital expenditures for all three of our business segments by approximately 60% compared to 2008, excluding acquisitions, in order to focus keeping our capital expenditures within anticipated internally generated cash flow.

Executive Summary

Contract Drilling

Our fourth quarter 2008 utilization rate was 74%, compared to 85% and 80% in the third quarter 2008 and fourth quarter 2007, respectively. Dayrates for the fourth quarter of 2008 averaged $19,330, an increase of 4% from the third quarter of 2008 and 7% from the fourth quarter of 2007. Direct profit (contract drilling revenue less contract drilling operating expense) decreased 12% from the third quarter of 2008 and 3% from the fourth quarter of 2007, primarily due to the decrease in utilization. Operating cost per day increased 10% from the third quarter of 2008 and increased 10% from the fourth quarter of 2007. In the third quarter of 2008, prices for oil and natural gas started to decrease and continued to decrease throughout the fourth quarter of 2008 and we anticipate will continue to decrease, for an unknown period of time which will further reduce our dayrates and utilization.

We finished constructing one new 1,500 horsepower diesel electric drilling rig which was placed into service in the fourth quarter of 2008 in North Dakota. Mobilization has been delayed on an additional 1,500 horsepower diesel electric drilling rig to work in North Dakota that we previously announced to be placed in service during the first quarter of 2009, pending final negotiations with the customer. Regarding the plans for constructing additional drilling rigs see the above discussion in Business Outlook . Our anticipated 2009 capital expenditures for this segment are $77.0 million.

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Oil and Natural Gas

Fourth quarter 2008 production from our oil and natural gas segment was 183,000 Mcfe per day, a 6% increase over the third quarter of 2008 and a 15% increase over the fourth quarter of 2007. The increase from the third quarter 2008 resulted from the third quarter 2008 shut-in of approximately 400 MMcfe of production due to the impact Hurricanes Gustav and Ike had on the infrastructure necessary for ongoing production activity in the affected areas and production from new wells completed during the fourth quarter. The increase from the fourth quarter 2007 resulted from production from new wells completed throughout 2008.

Oil and natural gas revenues decreased 30% from the third quarter of 2008 and decreased 6% from the fourth quarter of 2007. Our oil, natural gas and NGL prices in the fourth quarter of 2008, decreased 24%, 32% and 58%, respectively, from the third quarter of 2008 and our oil, natural gas and NGL prices decreased 12%, 12% and 51%, respectively, from the fourth quarter of 2007. Direct profit (oil and natural gas revenues less oil and natural gas operating expense) decreased 32% from the third quarter of 2008 and decreased 6% from the fourth quarter of 2007. The decrease from the third quarter 2008 and the fourth quarter 2007 primarily resulted from the impact of lower natural gas prices. Operating cost per Mcfe produced decreased 24% from the third quarter of 2008 and decreased 18% from the fourth quarter of 2007. We had hedged 72% of our fourth quarter 2008 average daily oil production and approximately 36% of our fourth quarter 2008 average natural gas production in 2008 to help manage our cash flow and capital expenditure requirements. Currently for 2009, we have hedged 72% of our average daily oil production (based on our fourth quarter 2008 production) and approximately 69% of our average daily natural gas production (based on our fourth quarter 2008 production). Currently for 2010, we have hedged approximately 47% of our average daily natural gas production (based on our fourth quarter 2008 production).

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. After December 31, 2008 commodity prices have continued to decrease and should commodity prices remain below December 31, 2008 levels, an additional write-down of the carrying value of our oil and natural gas properties will be required for the quarter ending March 31, 2009.

Our estimated production for 2009 is approximately 63.0 to 64.0 Bcfe, or essentially unchanged from our 2008 production. We currently anticipate that we will participate in the drilling of approximately 175 wells during 2009, a decrease of 37% over 2008. Our current anticipated 2009 capital expenditures for this segment are $200.0 million.

Commodity prices which started to decrease during the third quarter of 2008, continued to decrease throughout the fourth quarter of 2008 and into 2009. We anticipate these prices will remain at their current lower levels for an indeterminable period of time. As a result of these lower commodity prices combined with service costs that remain relatively high, we began slowing our drilling activity during the fourth quarter of 2008 and will continue to do so into 2009. In the Mid-Continent area, natural gas spot prices have been very weak and in certain situations we have shut-in production rather than selling the production at those prices.

Mid-Stream

Fourth quarter 2008 liquids sold per day decreased 1% from the third quarter of 2008 and increased 16% from the fourth quarter of 2007. Liquids sold per day decreased from the third quarter of 2008 primarily due to operating the processing plants in an ethane rejection mode due to an extremely low ethane price, and increased from the fourth quarter of 2007 primarily as the result of upgrades and expansions to existing plants. Gas processed per day increased 2% and 23% over the third quarter of 2008 and the fourth quarter of 2007, respectively. In 2007, 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 4% from the third quarter of 2008 and 12% from the fourth quarter of 2007 primarily from our Southeast Oklahoma gathering system experiencing natural production declines associated with connected wells.

NGL prices, including hedges, in the fourth quarter of 2008 decreased 41% from the price received in the third quarter of 2008 and decreased 31% over the price received in the fourth quarter of 2007. 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 had hedged 50% of our fourth quarter 2008 average fractionation spread volumes to help manage our cash flow from this segment in 2008. We currently do not have any fractionation spread hedges in place for 2009 and beyond.

Direct profit (mid-stream revenues less mid-stream operating expense) decreased 57% from the third quarter of 2008 and decreased 43% from the fourth quarter of 2007. The decrease from the third quarter 2008 and the fourth quarter 2007 resulted primarily from decreased commodity prices. Total operating cost for our mid-stream segment decreased 45% from the third quarter of 2008 and decreased 24% from the fourth quarter of 2007. Our anticipated capital expenditures for 2009 for this segment are $13.0 million. Commodity prices started to decline in the third quarter of 2008, continued to decrease throughout the fourth quarter of 2008 and into 2009. Prices may continue to decrease or remain at their current lower levels for an indeterminable period of time, which could result in fewer wells being connected to existing gathering systems and lower fractionation spreads resulting in possible future declines in volumes or margins.

Critical Accounting Policies and Estimates

Summary

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

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

Accounting Policies	Estimates or Assumptions	Accounts Affected
Full cost method of accounting for oil, NGLs and natural gas properties	Oil, NGLs and natural gas reserves, estimates and related present value of future net revenues Valuation of unproved properties Estimates of future development costs Derivatives measured at fair value	Oil and natural gas properties Accumulated depletion, depreciation and amortization Provision for depletion, depreciation and amortization Impairment of oil and natural gas properties Long-term debt and interest expense
Accounting for ARO for oil, NGLs and natural gas properties	Cost estimates related to the plugging and abandonment of wells Timing of cost incurred	Oil and natural gas properties Accumulated depletion, depreciation and amortization Provision for depletion, depreciation and amortization Current and non-current liabilities Operating expense
Accounting for impairment of long-lived assets	Forecast of undiscounted estimated future net operating cash flows	Drilling and mid-stream property and equipment Accumulated depletion, depreciation and amortization Provision for depletion, depreciation and amortization Other intangible assets
Goodwill	Forecast of discounted estimated future net operating cash flows	Accumulated depletion, depreciation and amortization Provision for depletion, depreciation and amortization
Turnkey and footage drilling contracts	Estimates of costs to complete turnkey and footage contracts	Revenue and operating expense Current assets and liabilities
Accounting for value of stock compensation awards	Estimates of stock volatility Estimates of expected life of awards granted Estimates of rates of forfeitures	Oil and natural gas properties Shareholder s equity Operating expenses General and administrative expenses
Accounting for derivative instruments and hedging	Derivatives measured at fair value Derivatives measured for effectiveness and ineffectiveness Non-qualifying derivatives measured at fair value	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 and valuation 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 based on experience and training. Each year, we hire an independent petroleum engineering firm to audit our internal evaluation of

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our oil, NGLs and natural gas reserves. The wells or locations for which estimates of reserves were audited were reserves that comprised the top 82% 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, 2008.

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

Type of Reserves	Nature of Available Data	Degree of Accuracy
Proved undeveloped	Data from offsetting wells, seismic data	Less accurate
Proved developed non-producing	Logs, core samples, well tests, pressure data	More accurate
Proved developed producing	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. SEC financial accounting and reporting standards require that the pricing we use be tied to the price we received for our oil, NGLs and natural gas on the last day of the reporting period. This requirement can result in significant changes from period to period given the volatile nature of oil, NGLs and natural gas prices. For example, based on our year end 2008 oil, NGLs and natural gas reserves, a $1.00 decline in the price used to calculate our economically recoverable oil and NGLs reserves will reduce our estimated oil reserves by 63,000 barrels and estimated NGL reserves by 28,000 barrels and a $0.10 decline in the price of natural gas used to calculate our natural gas reserves will reduce our estimated economically recoverable natural gas reserves by 1,401,000 Mcf. Estimated future cash flows discounted at 10% before income taxes would change by $31.7 million.

We compute our provision for DD&A on a units-of-production method. Each quarter, we use the following formulas to compute the provision for DD&A for our producing properties:

DD&A Rate = Unamortized Cost / Beginning of Period Reserves

Provision for DD&A = DD&A Rate x Current Period Production

Oil, NGLs and natural gas reserve estimates have a significant impact on our DD&A rate. If reserve estimates for a property or group of properties are revised downward in the future, the DD&A rate will increase as a result of the revision. Alternatively, if reserve estimates are revised upward, the DD&A rate will decrease. Based on our 2008 production level of 63,368,000 equivalent Mcf, a 5% decline in the amount of our 2008 oil, NGLs and natural gas reserves would increase our DD&A rate by $0.13 per Mcfe and would decrease pre-tax income by $8.2 million annually. A 5% increase in the amount of our 2008 oil, NGLs and natural gas reserves would decrease our DD&A rate by $0.12 per Mcfe and would increase pre-tax income by $7.6 million annually.

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 period-end oil, NGLs and natural gas prices 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 December 31, 2008 unescalated prices of $44.60 per barrel of oil, $26.04 per barrel of NGLs and $5.71 per Mcf of natural gas, adjusted for regional price differentials, for the estimated life of the respective properties, the unamortized cost of our oil and natural gas properties exceeded the ceiling of our proved oil, NGL and natural gas reserves. 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 these declines in commodity prices. After December 31, 2008 commodity prices have continued to decrease and should commodity prices remain below December 31, 2008 levels, an additional write-down of the carrying value of our oil and natural gas properties will be required for the quarter ending March 31, 2009.

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, 2008, which consisted of swaps and collars, covered 40.2 Bcfe and 23.7 Bcfe in 2009 and 2010, respectively. The effect of these cash flow hedges was a $96.0 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 12 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 under Financial Accounting Standards No. 143 (FAS 143), Accounting for Asset Retirement Obligations, 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 plugging 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. 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 impairment was recorded at December 31, 2008.

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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, 2008.

Turnkey and Footage Drilling Contracts. In our contract drilling operations, because we 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 2008 and 2007, 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. Effective January 1, 2006, we adopted SFAS No. 123 (revised 2004), Share-Based Payment, (SFAS 123(R)) to account for stock-based compensation. Under this method, 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 for adoption, 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 under Statement of Financial Accounting Standard No. 133 (subsequently amended by Financial Accounting Standard No. s 137, 138 and 149), Accounting for Derivative Instruments and Hedging Activities (FAS 133). We have hedged a portion of our anticipated oil, NGLs and natural gas production for the next 12-24 months. This statement requires all derivatives to be recognized on the balance sheet and measured at fair value. If a derivative is designated as a cash flow hedge, we are required to measure the effectiveness of the hedge, or the degree that the gain (loss) for the hedging instrument offsets the loss (gain) on the hedged item, at each reporting period. The effective portion of the gain (loss) on the derivative instrument is recognized in other comprehensive income as a component of equity and subsequently reclassified into earnings when the forecasted transaction affects earnings. The ineffective portion of a derivative s change in fair value is required to be recognized in earnings immediately. Derivatives that do not qualify for hedge treatment under FAS 133 must be recorded at fair value with gains (losses) recognized in earnings in the period of change.

New Accounting Standards

Fair Value Measurements. In September 2006, the FASB issued Statement No. 157 (FAS 157), Fair Value Measurements, which establishes a framework for measuring fair value and requires additional disclosures about fair value measurements. Beginning January 1, 2008, we partially applied FAS 157 as allowed by FASB Staff Position (FSP) 157-2, which delayed the effective date of FAS 157 for nonfinancial assets and liabilities. As of January 1, 2008, we have applied the provisions of FAS 157 to our financial instruments and the impact was not material. Under FSP 157-2, we will be required to apply FAS 157 to our nonfinancial assets and liabilities beginning January 1, 2009. We do not anticipate the applicability of FAS 157 to our nonfinancial assets and liabilities will have a material impact on our consolidated financial statements.

Business Combinations. In December 2007, the FASB issued Statement No. 141R (FAS 141R), Business Combinations, which will require most identifiable assets, liabilities, noncontrolling interest (previously referred to as minority interests) and goodwill acquired in a business combination to be recorded at full fair value. FAS 141R is effective for our year beginning January 1, 2009, and will be applied prospectively. We do not anticipate the adoption of FAS 141R will have a material impact on our consolidated financial statements, absent any material business combinations.

Noncontrolling Interests. In December 2007, the FASB issued Statement No. 160 (FAS 160), Noncontrolling Interest in Consolidated Financial Statements an Amendment to ARB No. 51, which requires noncontrolling interests (previously referred to as minority interests) to be reported as a component of equity. FAS 160 is effective for our year beginning January 1, 2009, and will require retroactive adoption of the presentation and disclosure requirements for existing minority interests. Since we currently do not have any noncontrolling interests, this standard does not presently have an impact on us.

Disclosures about Derivative Instruments and Hedging Activities. In March 2008, the FASB issued Statement No. 161 (FAS 161), Disclosures About Derivative Instruments and Hedging Activities an Amendment of FASB Statement 133, which requires enhanced disclosures about how derivative and hedging activities affect our financial position, financial performance and cash flows. FAS 161 is effective for our year beginning January 1, 2009, and will be applied prospectively. This statement will not have a significant impact on us due to it only requiring enhanced disclosures.

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 disclosure requirements 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 upon 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 upon the first-of-month posted price for each month in the prior twelve-month period. The new oil and gas reporting requirements are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009, with early adoption not permitted. We are currently evaluating the impact the new rules may have on our consolidated financial statements.

Financial Condition and Liquidity

Summary. Our financial condition and liquidity depends on the cash flow from our operations and borrowings under our bank 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.

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

	2008	2007	2006
	(In thousands except percentages)		
Working capital	$ 90,186	$ 40,611	$ 71,998
Long-term debt	$ 199,500	$ 120,600	$ 174,300
Shareholders equity (1)	$ 1,633,099	$ 1,434,817	$ 1,158,036
Ratio of long-term debt to total capitalization (1)	10.9%	7.8%	13.1%
Net income (1)	$ 143,625	$ 266,258	$ 312,177
Net cash provided by operating activities	$ 689,913	$ 577,571	$ 506,702
Net cash used in investing activities	$ (806,141)	$ (512,333)	$ (540,723)
Net cash provided by (used in) financing activities	$ 115,736	$ (64,751)	$ 33,663

(1) 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:

	2008	2007	2006
Contract Drilling:			
Average number of our drilling rigs in use during the period	103.1	99.4	109.0
Total number of drilling rigs owned at the end of the period	132	129	117
Average dayrate	$ 18,458	$ 18,663	$ 18,767
Oil and Natural Gas:			
Oil production (MBbls)	1,261	1,091	1,012
Natural gas liquids production (MBbls)	1,388	785	441
Natural gas production (MMcf)	47,473	43,464	44,169
Average oil price per barrel received	$ 93.87	$ 70.61	$ 63.39
Average oil price per barrel received excluding hedges	$ 98.02	$ 70.61	$ 63.39
Average NGL price per barrel received	$ 47.42	$ 45.03	$ 36.08
Average NGL price per barrel received excluding hedges	$ 47.38	$ 45.01	$ 36.08
Average natural gas price per mcf received	$ 7.62	$ 6.30	$ 6.17
Average natural gas price per mcf received excluding hedges	$ 7.53	$ 6.24	$ 6.17
Mid-Stream:			
Gas gathered MMBtu/day	197,367	219,635	247,537
Gas processed MMBtu/day	67,796	50,350	31,833
Gas liquids sold gallons/day	195,837	129,421	66,902
Number of natural gas gathering systems	37	36	37
Number of processing plants	9	8	6

At December 31, 2008, we had unrestricted cash totaling $0.6 million and we had borrowed $199.5 million of the $325.0 million we had elected to have available under our Credit Facility. Our Credit Facility is used for working capital and capital expenditures. Historically, most of our capital expenditures have been discretionary and directed toward future growth. However, for 2009 in view of the current economic environment and declines in commodity prices, our focus will be aimed at keeping our capital expenditures within anticipated internally generated cash flows which may not result in future growth.

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 $90.2 million, $40.6 million and $72.0 million as of December 31, 2008, 2007 and 2006, respectively. The effect of our derivatives increased working capital by $32.4 million, $1.3 million and $1.3 million as of December 31, 2008, 2007 and 2006, respectively.

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Contract Drilling. Our 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 recent depressed conditions within our industry continue, we do not anticipate that competition to keep and attract qualified employees to meet our immediate future requirements will materially effect us. Likewise, if current commodity price and industry drilling utilization declines continue, we do not anticipate that our drilling labor costs will increase from those levels in effect at the beginning of the fourth quarter of 2008.

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 2008, our average dayrate was $18,458 per day compared to $18,663 per day in 2007 and $18,767 per day in 2006. The average number of our drilling rigs used in 2008 was 103.1 drilling rigs (79%) compared with 99.4 drilling rigs (80%) in 2007 and 109.0 drilling rigs (96%) for 2006. Based on the average utilization of our drilling rigs during 2008, a $100 per day change in dayrates has a $10,310 per day ($3.8 million annualized) change in our pre-tax operating cash flow. Industry demand for our drilling rigs remained strong throughout the first nine months of 2006 before declining in the fourth quarter of 2006 and into 2007. This was followed by a resurgence in activity during the first nine months of 2008, before a decline in activity during the fourth quarter 2008. The reduction in demand for drilling rigs in the fourth quarter of 2008 was primarily the result of the evaluation of the economics of drilling prospects by the operators using our contract drilling services after natural gas prices declined significantly in the last half of the third quarter of 2008 being due to the global economic crisis and low commodity prices. We expect that utilization and dayrates for our drilling rigs will continue to 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 2008, 2007 and 2006, we drilled 122, 77 and 72 wells, respectively, for our exploration and production subsidiary. The profit associated with these wells received by our contract drilling segment of $27.9 million, $22.7 million and $22.2 million during 2008, 2007 and 2006, 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 79% of our oil, NGLs and natural gas reserves. Any significant change in natural gas prices has a material affect 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 2008, 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 $371,000 per month ($4.5 million annualized) change in our pre-tax operating cash flow. Our 2008 average natural gas price was $7.62 compared to an average natural gas price of $6.30 for 2007 and $6.17 for 2006. A $1.00 per barrel change in our oil price, without the effect of hedging, would have an $99,000 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 $109,000 per month ($1.3 million annualized) change in our pre-tax operating cash flow based on our production in 2008. Our 2008 average oil price per barrel was $93.87 compared with an average oil price of $70.61 in 2007 and $63.39 in 2006 and our 2008 average NGL price per barrel was $47.42 compared with an average liquids price of $45.03 in 2007 and $36.08 in 2006.

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Because natural gas prices have such a significant affect on the value of our oil, NGLs and natural gas reserves, declines in these prices can result in a decline in the carrying value of our oil and natural gas properties. Based on December 31, 2008 unescalated prices of $44.60 per barrel of oil, $26.04 per barrel of NGLs and $5.71 per Mcf of natural gas, adjusted for regional price differentials, for the estimated life of the respective properties, the unamortized cost of our oil and natural gas properties exceeded the ceiling of our proved oil, NGL and natural gas reserves. 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 these declines in commodity prices. After December 31, 2008 commodity prices have continued to decrease and should commodity prices remain below December 31, 2008 levels, an additional write-down of the carrying value of our oil and natural gas properties will be required for the quarter ending March 31, 2009. 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 and selling, gathering, processing and treating of natural gas and operates three natural gas treatment plants, nine processing plants, 37 gathering systems and 770 miles of pipeline. Superior operates in Oklahoma, Texas, Louisiana, 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 2008, 2007 and 2006 this segment purchased $52.0 million, $18.4 million and $8.0 million, respectively of our natural gas production and natural gas liquids and provided gathering and transportation services of $4.3 million, $4.7 million and $5.3 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 condensed financial statements.

Our mid-stream segment gathered 197,367 MMBtu per day in 2008 compared to 219,635 MMBtu per day in 2007 and 247,537 MMBtu per day in 2006, processed 67,796 MMBtu per day in 2008 compared to 50,350 MMBtu per day in 2007 and 31,833 MMBtu per day in 2006 and sold NGLs of 195,837 gallons per day in 2008 compared to 129,421 gallons per day in 2007 and 66,902 gallons per day in 2006. Gas gathering volumes per day in 2008 decreased 10% compared to 2007 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 addition of three natural gas processing plants in 2007 and also resulted in increased NGL volumes.

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, 2008, 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 2008 was 4.5%. At December 31, 2008 and February 13, 2009, borrowings were $199.5 million and $193.5 million, respectively.

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

Lender	Participation Interest
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%
	100.00%

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 $500.0 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 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%, payable at the end of each month and the principal borrowed may be paid at any time, in part or in whole, without premium or penalty. At December 31, 2008, $170.0 million of our then outstanding borrowings of $199.5 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, 2008, we were in compliance with the covenants contained in the Credit Facility.

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We entered into the following interest rate swaps to help manage our exposure to possible future interest rate increases:

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

Capital Requirements

Drilling Acquisitions and Capital Expenditures. In January 2006, we acquired a 1,000 horsepower drilling rig for approximately $3.9 million. This newly acquired drilling rig was modified at one of our drilling yards for an additional $1.7 million and became operational in April 2006. In May 2006, we moved a 1,500 horsepower drilling rig to our Rocky Mountain division following completion of its construction for approximately $10.2 million. In the second quarter of 2006, we also completed the purchase of two new 1,500 horsepower drilling rigs for a total of $15.2 million of which $4.6 million was paid before the second quarter of 2006 and the balance of $10.6 million was paid at delivery of the drilling rigs. An additional $3.0 million of modifications were made to the drilling rigs before the drilling rigs were placed into service. The first drilling rig was placed into service in May 2006 and the second drilling rig was placed into service in June 2006. At the end of August 2006 we completed the construction of another 1,500 horsepower drilling rig for approximately $9.5 million which was moved into our Rocky Mountain division. In the last half of 2006 we completed construction of a 750 horsepower rig for approximately $4.5 million.

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 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, as a result of the significant decline in commodity prices and the resulting drop in demand for our drilling rigs, we stored a 1,500 horsepower diesel electric drilling rig in our Oklahoma City rig fabrication facility and yard that was scheduled to be placed into service in North Dakota during the first quarter of 2009. The mobilization has been delayed pending final negotiation with our customer. In addition, after discussions with our customers, we postponed the construction of eight additional drilling rigs we had previously anticipated building and instead substituted drilling rigs we already owned. As a result of existing contractual obligations, we expect to take delivery of a new drilling rig during the fourth quarter of 2009.

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We currently do not have a shortage of drill pipe and drilling equipment. At December 31, 2008, we had commitments to purchase approximately $21.6 million of drilling rig components and $27.8 million of drill pipe and drill collars in 2009. We also had committed to purchase $14.8 million of drill pipe and drill collars in 2010. Our anticipated capital expenditures for 2009 are $77.0 million.

Oil and Natural Gas Acquisitions and Capital Expenditures. Most of our capital expenditures 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 278 gross wells (134.31 net wells) in 2008 compared to 253 gross wells (96.64 net wells) in 2007 and 244 gross wells (85.30 net wells) in 2006. Our 2008 total capital expenditures for our oil and natural gas segment, excluding a $13.9 million plugging liability, totaled $547.7 million. Currently we plan to participate in drilling an estimated 175 gross wells in 2009 and estimate our total capital expenditures for our oil and natural gas segment will be approximately $200.0 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 May 16, 2006, we closed the acquisition of certain oil and natural gas properties from a group of private entities for approximately $32.4 million in cash. Proved oil, NGLs and natural gas reserves involved in this acquisition consisted of approximately 14.2 Bcfe. The effective date of this acquisition was April 1, 2006 and results from this acquisition were included in the statement of income beginning May 1, 2006.

On October 13, 2006, we completed the acquisition of Brighton Energy, L.L.C., a privately owned oil and natural gas company for approximately $67.0 million in cash. Included in this acquisition was all of Brighton s oil and natural gas assets (excluding Atoka and Coal counties in Oklahoma) and included approximately 23.1 Bcfe of proved reserves. The majority of the acquired reserves are located in the Anadarko Basin of Oklahoma and the onshore Gulf Coast basins of Texas and Louisiana, with additional reserves in Arkansas, Kansas, Montana, North Dakota and Wyoming. This acquisition had an effective date of August 1, 2006 and results of operations from this acquisition are included in the statement of income beginning October 1, 2006 with the results for the period from August 1, 2006 through September 30, 2006 included as an adjustment to the purchase price.

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, we acquired interest in approximately 55,000 undeveloped acres in the Marcellus Shale, located mainly in Pennsylvania for approximately $40.1 million.

As of December 31, 2008, we had commitments to purchase casing for $10.6 million.

Mid-Stream Acquisitions and Capital Expenditures. In September 2006, we closed the acquisition of Berkshire Energy, LLC, a private company for an adjusted purchase price of $21.7 million. The principal tangible assets of the acquired company consisted of a natural gas processing plant, a natural gas gathering

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system with 15 miles of pipeline, three field compressors and two plant compressors. This purchase had an effective date of July 31, 2006. The financial results of this acquisition are included in the company s statement of income from September 1, 2006 forward with the results for the period of August 1, 2006 through August 31, 2006 included as an adjustment to the purchase price.

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. Our remaining commitment for the second plant is $4.7 million.

During 2008, our mid-stream segment incurred $49.9 million in capital expenditures as compared to $34.2 million in 2007 and $42.9 million in 2006, including acquisitions. For 2009, we have budgeted capital expenditures of approximately $13.0 million.

Contractual Commitments. At December 31, 2008, we had the following contractual obligations:

		Payments Due by Period			
	Total	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
			(In thousands)		
Bank debt (1)	$ 222,764	$ 6,812	$ 13,623	$ 202,329	$
Retirement agreements (2)	110	110			
Operating leases (3)	2,835	2,041	775	19	
Drill pipe, drilling components and equipment purchases (4)	79,565	64,749	14,816		
Total contractual obligations	$ 305,274	$ 73,712	$ 29,214	$ 202,348	$

(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 3.4% which includes the effect of the interest rate swaps.

(2) In the second quarter of 2001, we recorded $1.3 million in additional employee benefit expenses for the present value of a separation agreement made in connection with the retirement of King Kirchner from his position as chief executive officer. The liability associated with this expense, including accrued interest, is paid in monthly payments of $25,000 which started in July 2003 and continues through June 2009.

(3) We lease office space or yards in Tulsa and Woodward, Oklahoma; Canadian, Houston and Midland, Texas; Englewood and Denver, Colorado; Pinedale, Wyoming; and Pittsburg, Pennsylvania under the terms of operating leases expiring through January, 2012. We recently closed our offices in Woodward and Midland and our leases for those offices expire in March and November 2009, respectively. Additionally, we have several equipment leases and lease space on short-term commitments to stack excess drilling rig equipment and production inventory.

(4) For the next twelve months, we have committed to purchase approximately $49.4 million of new drilling rig components, drill pipe, drill collars and related equipment, $10.6 million of casing and $4.7 million for a new processing plant. Beyond 2009, we have committed to purchase approximately $14.8 million of new drill pipe and drill collars.

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At December 31, 2008, we also had the following commitments and contingencies that could create, increase or accelerate our liabilities:

		Estimated Amount of Commitment Expiration Per Period			
Other Commitments	**Total Accrued**	**Less Than 1 Year**	**2-3 Years**	**4-5 Years**	**After 5 Years**
			(In thousands)		
Deferred compensation plan (1)	$ 2,030	Unknown	Unknown	Unknown	Unknown
Separation benefit plans (2)	$ 6,435	$ 277	Unknown	Unknown	Unknown
Derivative liabilities interest rate swaps	$ 2,516	$ 736	$ 1,473	$ 307	$
Derivative liabilities commodity hedges	$ 745	$ 745	$	$	$
Plugging liability (3)	$ 49,230	$ 1,113	$ 12,208	$ 3,180	$ 32,729
Gas balancing liability (4)	$ 3,364	Unknown	Unknown	Unknown	Unknown
Repurchase obligations (5)	$	Unknown	Unknown	Unknown	Unknown
Workers compensation liability (6)	$ 23,473	$ 9,115	$ 4,030	$ 1,595	$ 8,733

(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. At December 31, 2008, there were 38 eligible employees to participate in the Special Plan. On December 31, 2008, all these plans were amended to bring the plans into compliance with Section 409A of the Internal Revenue Code of 1986, as amended.

(3) When a well is drilled or acquired, under Financial Accounting Standards No. 143 (FAS 143), Accounting for Asset Retirement Obligations, 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 2008, 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 $241,000 and $7,000 in 2008 and 2006, 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.

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Hedging Activities. 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, 2008, we had two outstanding interest rate swaps which were cash flow hedges. There was no material amount of ineffectiveness. Our December 31, 2008 balance sheet recognized the fair value of these swaps as current and non-current derivative liabilities and is presented in the following table:

Term		Amount	Fixed Rate	Floating Rate	Fair Value Asset (Liability)
			($ in thousands)		
December 2007	May 2012	$ 15,000	4.53%	3 month LIBOR	$ (1,351)
December 2007	May 2012	$ 15,000	4.16%	3 month LIBOR	(1,165)
					$ (2,516)

Because of these interest rate swaps, interest expense increased by $0.3 million in 2008 and decreased by $0.7 million and $0.5 million in 2007 and 2006, respectively. A loss of $1.6 million, net of tax, is reflected in accumulated other comprehensive income (loss) as of December 31, 2008.

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 products is based, in part, on our view of current and future market conditions. For 2008, in an attempt to better manage our cash flows, we increased the amount of our hedged production. Based on our fourth quarter 2008 average daily production, as of February 13, 2009, the approximated percentages we have hedged are as follows:

Oil and Natural Gas Segment:

	January December 2009	January December 2010
Daily oil production	72%	%
Daily natural gas production	69%	47%

With respect to the commodities subject to the hedge, the use of hedging limits the risk of adverse downward price movements, however it also limits increases in future revenues that would otherwise result from 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 in our valuation at December 31, 2008 and determined it was immaterial at that time. At February 13, 2009, Bank of Montreal, Bank of Oklahoma, N.A., 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, 2008, the fair values of the net assets (liabilities) we had with each of these counterparties was $33.0 million, $9.1 million, $13.7 million, $0.5 million, $1.0 million and ($0.7) million, respectively.

In accordance with FASB Interpretation No. 39, 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, 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

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liabilities of $0.7 million. At December 31, 2007, we recorded the fair value of our commodity derivatives on our balance sheet as current derivative assets of $2.0 million and current derivative liabilities of $0.1 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, 2008, we had a gain of $34.9 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 upon the market prices at December 31, 2008, we expect to transfer approximately $31.7 million, net of tax, of the gain included in the balance in accumulated other comprehensive income (loss) to earnings during the next 12 months in the related month of production. All derivative instruments as of December 31, 2008 are expected to mature by December 31, 2010.

Pursuant to FAS 133, certain derivatives do not qualify for designation as cash flow hedges. Currently, we have two basis swaps that do not qualify as cash flow hedges. 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. Following provisions of FAS 133, 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:

	2008	2007	2006
		(In thousands)	
Increases (decreases) in:			
Oil and natural gas revenue:			
Realized gains (losses) on oil and natural gas derivatives	$ (1,010)	$ 2,589	$
Unrealized gains on ineffectiveness of cash flow hedges	255		
Unrealized gains on non-qualifying oil and natural gas derivatives	1,047		
Total increase on oil and natural gas revenues due to derivatives	292	2,589	
Gas gathering and processing revenue (all realized gains (losses))	2,022	(2,078)	
Gas gathering and processing expense (all realized losses)	1,438	1,694	
Impact on pre-tax earnings	$ 876	$ (1,183)	$

Stock and Incentive Compensation. 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. We also granted awards covering 101,236 shares of stock appreciation rights to certain of our executive officers in 2007. In 2006, 44,665 shares of SARs were granted. During 2008, we recognized compensation expense of $11.1 million for all of our restricted stock, stock options and SAR grants and capitalized $3.3 million of compensation cost for oil and natural gas properties. The 2008 restricted stock awards had an estimated fair value as of the grant date of $1.5 million. Compensation expense will be recognized over the three year vesting periods, and during 2008, we recognized $0.5 million in additional compensation expense and capitalized $0.1 million for these 2008 awards granted.

Insurance. We are self-insured for certain losses relating to workers compensation, general liability, control of well and employee medical benefits. Insured policies for other coverage contain deductibles or retentions per occurrence that range from $5,000 for motor truck cargo liability to $1.0 million for general liability and 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 14 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 2008, 2007 and 2006, the total we received for all of these fees was $1.9 million, $1.6 million and $1.3 million, respectively. We expect that these fees for 2009 will be comparable to those in 2008. 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 seven 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 have various contractual commitments.

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Results of Operations

2008 versus 2007

Following is a comparison of selected operating and financial data:

	2008	2007	Percent Change
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. Prices have continued to decline for oil and natural gas during the first quarter of 2009 and may continue to do so, for an unknown period of time, which will further reduce our future dayrates and utilization.

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. However, if the recent depressed conditions within our industry continue, we do not anticipate that the competition we previously faced to keep and attract qualified employees will materially effect us. Likewise, if commodity prices and industry drilling utilization declines continue, we do not anticipate that our drilling labor costs will increase from those levels in effect at the beginning of the fourth quarter of 2008, and upward pressure on other daily drilling costs should also be reduced. 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, continued to decrease throughout the fourth quarter of 2008 and may continue to decrease or remain at their current lower levels for an indeterminable period of time. As a result of lower commodity prices combined with service costs that remain relatively high, we have slowed down our drilling activity during the fourth quarter of 2008 and will continue to do so into 2009.

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.

Total depreciation, depletion and amortization (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. Our DD&A in the first quarter of 2009 and throughout 2009 will be lower due to the write-down of the carrying value of our oil and natural gas properties in the fourth quarter of 2008 as discussed in the following paragraph. The increase in commodity prices over the last two years has increased the cost of acquiring producing properties. However, recent decreases in commodity prices, combined with nation-wide concerns regarding credit availability may lead to less competition for producing property acquisitions.

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 and should commodity prices remain below December 31, 2008 levels, an additional write-down of the carrying value of our oil and natural gas properties will be required for the quarter ending March 31, 2009.

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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, continued to decrease throughout the fourth quarter of 2008 and may continue to decrease or remain at their current lower levels for an indeterminable period of time, which could result in fewer wells being connected to existing gathering systems and lower fractionation spreads resulting in possible future declines in volumes or margins.

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.

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2007 versus 2006

Following is a comparison of selected operating and financial data:

	2007	2006	Percent Change
Total revenue	$ 1,158,754,000	$ 1,162,385,000	%
Net income	$ 266,258,000	$ 312,177,000	(15)%
Contract Drilling:			
Revenue	$ 627,642,000	$ 699,396,000	(10)%
Operating costs excluding depreciation	$ 304,780,000	$ 313,882,000	(3)%
Percentage of revenue from daywork contracts	100%	100%	%
Average number of drilling rigs in use	99.4	109.0	(9)%
Average dayrate on daywork contracts	$ 18,663	$ 18,767	(1)%
Depreciation	$ 56,804,000	$ 51,959,000	9%
Oil and Natural Gas:			
Revenue	$ 391,480,000	$ 357,599,000	9%
Operating costs excluding depreciation, depletion and amortization	$ 97,109,000	$ 81,120,000	20%
Average oil price (Bbl)	$ 70.61	$ 63.39	11%
Average NGL price (Bbl)	$ 45.03	$ 36.08	25%
Average natural gas price (Mcf)	$ 6.30	$ 6.17	2%
Oil production (Bbl)	1,091,000	1,012,000	8%
NGL production (Bbl)	785,000	441,000	78%
Natural gas production (Mcf)	43,464,000	44,169,000	(2)%
Depreciation, depletion and amortization rate (Mcfe)	$ 2.32	$ 2.04	14%
Depreciation, depletion and amortization	$ 127,417,000	$ 108,124,000	18%
Mid-Stream Operations:			
Revenue	$ 138,595,000	$ 101,863,000	36%
Operating costs excluding depreciation and amortization	$ 119,776,000	$ 88,834,000	35%
Depreciation and amortization	$ 11,059,000	$ 6,247,000	77%
Gas gathered MMBtu/day	219,635	247,537	(11)%
Gas processed MMBtu/day	50,350	31,833	58%
Gas liquids sold gallons/day	129,421	66,902	93%
General and administrative expense	$ 22,036,000	$ 18,690,000	18%
Interest expense, net	$ 6,362,000	$ 5,273,000	21%
Income tax expense	$ 147,153,000	$ 176,079,000	(16)%
Average interest rate	6.0%	5.9%	2%
Average long-term debt outstanding	$ 170,141,000	$ 135,617,000	25%

Contract Drilling:

Industry demand for our drilling rigs remained strong throughout the first nine months of 2006 before declining in the fourth quarter of 2006. Our utilization rate for 2007 was 80% as our utilization fluctuated slightly above or below the 80% level throughout the last six months of 2007. The reduction in demand for drilling rigs, which started in the fourth quarter of 2006, was primarily the result of the evaluation of the economics of drilling prospects by the operators using our contract drilling services after natural gas prices declined significantly in the last half of the third quarter of 2006. High levels of natural gas storage throughout the majority of the 2006 winter season and again during the summer of 2007 also contributed to reduced demand for drilling rigs. Drilling revenues decreased $71.8 million or 10% in 2007 versus 2006. Average rig utilization declined from 109.0 drilling rigs in 2006 to 99.4 in 2007. The decline in rig utilization decreased drilling revenues by $61.5 million while decreases in revenue per day between the comparative periods decreased revenue by $10.3 million. Our average dayrate in 2007 was 1% lower than in 2006. Our average dayrate in January 2007 was $19,713 and declined steadily throughout the year, averaging $17,945 in December 2007.

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Drilling operating costs decreased $9.1 million or 3% between 2007 and 2006. Operating cost decreased as a result of 9.6 fewer drilling rigs operating between the comparative years and reductions in workers compensation cost. Operating cost increased $509 per day in 2007 when compared with 2006 with $178 per day of the increase resulting from increases in direct drilling cost and $48 per day resulting from $1.8 million of bad debt expense. The remainder of the increase resulted from additional yard, truck and auto expense associated with the acquisition of additional facilities and equipment from our June 2007 rig acquisition and from increases in daily cost for rig maintenance and compensation expense to retain qualified drilling staff. Contract drilling depreciation increased $4.8 million or 9% as the total number of drilling rigs owned increased between the comparative periods.

Oil and Natural Gas:

Oil and natural gas revenues increased $33.9 million or 9% in 2007 as compared to 2006 due to an increase in equivalent production volumes of 3% and an increase in average oil, NGL and natural gas prices. Average oil prices between the comparative years increased 11% to $70.61 per barrel, NGL prices increased 25% to $45.03 per barrel and natural gas prices increased 2% to $6.30 per Mcf. In 2007, oil production increased 8% and NGL production increased 78% while natural gas production decreased by 2%. Natural gas production increases were limited in the first quarter of 2007 due to adverse weather which slowed the timing for completion of certain wells and pipeline construction delays which prevented the connection of wells that had recently been drilled and completed. Increased oil and NGL production came primarily from our ongoing development drilling activity and from acquisitions completed in 2006.

Oil and natural gas operating costs increased $16.0 million or 20% in 2007 as compared to 2006. An increase in the average cost per equivalent Mcf produced represented 81% of the increase in operating costs with the remaining 19% of the increase attributable to the increase in volumes produced from both development drilling and producing property acquisitions. Increases in general and administrative expenses directly related to oil and natural gas production, lease operating expenses and gross production taxes contributed to the majority of the operating cost increase. General and administrative expenses increased as labor costs increased primarily due to a 21% increase in the average number of employees working in the exploration and production area. Total DD&A increased $19.3 million or 18%. Higher production volumes accounted for 19% of the increase while increases in our DD&A rate represented 81% of the increase. The increase in our DD&A rate in 2007 compared to 2006 resulted primarily from a 10% increase in the cost of Mcf equivalents added to our reserves in 2007 compared to 2006.

Mid-Stream:

Our mid-stream revenues were $36.7 million or 36% higher in 2007 as compared to 2006 due to the higher NGL volumes sold and processed volumes combined with higher NGL and natural gas prices. The average price for NGLs sold increased 24% and the average price for natural gas sold increased 2%. Gas processing volumes per day increased 58% between the comparative years and NGLs sold per day increased 93% between the comparative years. An 11% 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 acquisition of a processing plant in September of 2006 and the installation of three processing plants in 2007 combined to a lesser extent with volumes added from new wells connected to existing systems throughout 2007. NGLs sold volumes per day increased due to recent upgrades to several of our processing facilities. Gas gathering volumes decreased primarily from a decline in volumes gathered from our Southeast Oklahoma gathering system due to natural declines of production in the formation and decreased well connections. NGL sales were reduced $2.1 million due to the impact of NGL hedges.

Operating costs increased $30.9 million or 35% in 2007 compared to 2006 due to a 33% increase in natural gas volumes purchased and a 5% increase in prices paid for natural gas purchased, a 54% increase in field direct operating cost due to the additions to our natural gas gathering and processing systems and the volume of natural gas processed and a 51% increase in general and administrative expenses. The total number of employees working in our mid-stream segment increased by 29%. Depreciation and amortization increased $4.8 million, or 77%, primarily attributable to the additional depreciation and amortization associated with tangible and intangible assets acquired between the comparative periods. Operating costs increased $1.7 million in 2007 over 2006 due to the impact of natural gas purchase hedges.

Other:

General and administrative expense increased $3.3 million or 18% in 2007 compared to 2006. The increase was primarily attributable to increased stock based compensation costs and increased payroll expenses due to a 16% increase in the number of employees added and to a lesser extent an increase in insurance cost.

Total interest expense increased $1.1 million or 21% between the comparative periods. Average debt outstanding was 25% higher in 2007 as compared to 2006 primarily due to the acquisition of producing properties in the last four months of 2006 and the acquisition of a drilling company in the second quarter of 2007. Average debt outstanding accounted for approximately 90% of the interest expense increase, with the remaining 10% resulting from an increase in average interest rates on our bank debt. Interest expense was reduced $0.7 million in 2007 and $0.5 million in 2006 from settlements on our interest rate swap. Associated with our increased level of undeveloped inventory of oil and natural gas properties, the construction of additional drilling rigs and the construction of gas gathering systems, we capitalized $4.6 million of interest in 2007 compared to $3.5 million in 2006.

Income tax expense decreased $28.9 million or 16% due primarily to the decrease in income before income taxes. Our effective tax rate for 2007 was 35.6% versus 36.1% in 2006 with the change due primarily to the increase in manufacturing tax deduction for 2007. The portion of our taxes reflected as current income tax expense for 2007 was $66.6 million or 45% of total income tax expense in 2007 as compared with $112.8 million or 64% of total income tax expense in 2006. The reduction in the percentage of tax expense recognized as current is the result of increased intangible drilling costs to be deducted in the current year. Income taxes paid in 2007 were $73.4 million.

In January 2006, one of our drilling rigs was destroyed by a fire. No personnel were injured although the drilling rig was a total loss. Insurance proceeds for the loss exceeded our net book value and provided a gain of approximately $1.0 million which is recorded in other revenues.

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. The prices we receive 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 these prices to continue to fluctuate. 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 2008 production, a $0.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $371,000 per month ($4.5 million annualized) change in our pre-tax cash flow. A $1.00 per barrel change in our oil price would have an $99,000 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 $109,000 per month ($1.3 million annualized) change in our pre-tax cash flow.

We use hedging 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. These transactions include financial price swaps whereby we will receive a fixed price for our

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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 two basis swaps that do not qualify as cash flow hedges. 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, 2008, the following cash flow hedges were outstanding:

Term	Sell/ Purch.	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Jan 09 Dec 09	Sell	Crude oil collar	500 Bbl/day	$100.00 put & $156.25 call	WTI NYMEX
Jan 09 Dec 09	Sell	Crude oil swap	2,000 Bbl/day	$51.87	WTI NYMEX
Jan 09 Dec 09	Sell	Natural gas collar	10,000 MMBtu/day	$8.22 put & $10.80 call	IF NYMEX (HH)
Jan 09 Dec 09	Sell	Natural gas swap	30,000 MMBtu/day	$7.01	IF Tenn Zone 0
Jan 09 Dec 09	Sell	Natural gas swap	30,000 MMBtu/day	$6.32	IF CEGT
Jan 09 Dec 09	Sell	Natural gas swap	25,000 MMBtu/day	$5.57	IF PEPL
Jan 10 Dec 10	Sell	Natural gas swap	20,000 MMBtu/day	$6.89	IF Tenn Zone 0
Jan 10 Dec 10	Sell	Natural gas swap	20,000 MMBtu/day	$6.62	IF CEGT
Jan 10 Dec 10	Sell	Natural gas swap	15,000 MMBtu/day	$7.20	IF NYMEX (HH)
Jan 10 Dec 10	Sell	Natural gas swap	10,000 MMBtu/day	$6.25	IF PEPL

At December 31, 2008, the following non-qualifying cash flow derivatives were outstanding:

Term	Sell/ Purch.	Commodity	Hedged Volume	Basis Differential	Hedged Market
Jan 09 Dec 09	Sell	Natural gas basis differential swap	10,000 MMBtu/day	($1.02)	PEPL NYMEX
Jan 09 Dec 09	Sell	Natural gas basis differential swap	10,000 MMBtu/day	($1.10)	CEGT NYMEX

Subsequent to December 31, 2008, the following cash flow hedges were entered into:

Term	Sell/ Purch.	Commodity	Hedged Volume	Weighted Average Basis Differential	Hedged Market
Jan 10 Dec 10	Sell	Natural gas basis differential swap	10,000 MMBtu/day	($0.79)	PEPL NYMEX

Interest Rate Risk. Our interest rate exposure relates to our long-term debt under our Credit Facility, all of which bears interest at variable rates based on the BOKF National Prime Rate or the LIBOR Rate. At our election, borrowings under our revolving 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. Based on our average outstanding long-term debt subject to the floating rate in 2008, a 1% increase in the floating rate would reduce our annual pre-tax cash flow by approximately $1.2 million.

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Item 8. ***Financial Statements and Supplementary Data***

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Unit Corporation and Subsidiaries

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Management s Report on Internal Control over Financial Reporting

Management of the company is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined in Rules 13a-15(f) or 15d-15(f) promulgated under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, the company s principal executive and principal financial officers and effected by the company s board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that:

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company;

- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and

- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

The company s management assessed the effectiveness of the company s internal control over financial reporting as of December 31, 2008. 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, 2008, 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, 2008, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

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Report of Independent Registered Public Accounting Firm

To Board of Directors and Shareholders of

Unit Corporation**:**

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index 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, 2008, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

PricewaterhouseCoopers LLP

Tulsa, Oklahoma

February 24, 2009

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UNIT CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	As of December 31, 2008	2007
	(In thousands except share and par value amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 584	$ 1,076
Restricted cash	20	19
Accounts receivable (less allowance for doubtful accounts of $4,893 and $3,350)	192,408	159,455
Materials and supplies	9,923	13,558
Current derivative asset (Note 12)	52,177	2,128
Current income tax receivable	11,768	5,505
Prepaid expenses and other	19,705	15,274
Total current assets	286,585	197,015
Property and equipment:		
Drilling equipment	1,172,655	987,184
Oil and natural gas properties, on the full cost method:		
Proved properties	2,090,623	1,624,478
Undeveloped leasehold not being amortized	160,034	64,722
Gas gathering and processing equipment	169,402	119,515
Transportation equipment	33,611	23,240
Other	22,484	19,974
	3,648,809	2,839,113
Less accumulated depreciation, depletion, amortization and impairment	1,447,157	927,759
Net property and equipment	2,201,652	1,911,354
Goodwill	62,808	62,808
Other intangible assets, net	9,384	13,798
Non-current derivative asset (Note 12)	5,218	
Other assets	16,219	14,844
Total assets	$ 2,581,866	$ 2,199,819
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 129,755	$ 100,258
Accrued liabilities	51,659	40,452
Contract advances	2,889	6,825
Current portion of derivative liabilities (Note 5 and 12)	1,481	113
Current portion of other long-term liabilities (Note 5)	10,615	8,756
Total current liabilities	196,399	156,404

Long-term debt (Note 5)	199,500	120,600
Other long-term derivative liabilities (Note 5 and 12)	1,780	193
Other long-term liabilities (Note 5)	74,027	58,922
Deferred income taxes (Note 7)	477,061	428,883
Commitments and contingencies (Note 14)		
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, 47,255,964 and 47,035,089 shares issued as of December 31, 2008 and 2007, respectively	9,325	9,280
Capital in excess of par value	367,000	344,512
Accumulated other comprehensive income (net of tax of $19,548 and $662, respectively)	33,284	1,160
Retained earnings	1,223,490	1,079,865
Total shareholders equity	1,633,099	1,434,817
Total liabilities and shareholders equity	$ 2,581,866	$ 2,199,819

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

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UNIT CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31, 2008	2007	2006
	(In thousands except per share amounts)		
Revenues:			
Contract drilling	$ 622,727	$ 627,642	$ 699,396
Oil and natural gas	553,998	391,480	357,599
Gas gathering and processing	181,730	138,595	101,863
Other	(362)	1,037	3,527
Total revenues	1,358,093	1,158,754	1,162,385
Expenses:			
Contract drilling:			
Operating costs	312,907	304,780	313,882
Depreciation	69,841	56,804	51,959
Oil and natural gas:			
Operating costs	116,239	97,109	81,120
Depreciation, depletion and amortization	159,550	127,417	108,124
Impairment of oil and natural gas properties (Note 2)	281,966		
Gas gathering and processing:			
Operating costs	150,466	119,776	88,834
Depreciation and amortization	14,822	11,059	6,247
General and administrative	25,419	22,036	18,690
Interest, net	1,304	6,362	5,273
Total expenses	1,132,514	745,343	674,129
Income before income taxes	225,579	413,411	488,256
Income tax expense:			
Current	40,877	66,642	112,812
Deferred	41,077	80,511	63,267
Total income taxes	81,954	147,153	176,079
Net income	$ 143,625	$ 266,258	$ 312,177
Net income per common share:			
Basic	$ 3.08	$ 5.74	$ 6.75
Diluted	$ 3.06	$ 5.71	$ 6.72

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

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UNIT CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS EQUITY

Year Ended December 31, 2006, 2007 and 2008

	Common Stock	Capital In Excess of Par Value	Accumulated Other Comprehensive Income	Unearned Compensation - Restricted Stock	Retained Earnings	Total
			(In thousands except share amounts)			
Balances, January 1, 2006	$ 9,236	$ 328,037	$ 485	$ (2,226)	$ 501,430	$ 836,962
Comprehensive income:						
Net Income					312,177	312,177
Other comprehensive income (net of tax of $701 and ($202)):						
Change in value of cash flow derivative instruments used as cash flow hedges			1,188			1,188
Reclassification derivative settlements			(334)			(334)
Total comprehensive income						313,031
Activity in employee compensation plans (105,217 shares)	21	5,796		2,226		8,043
Balances, December 31, 2006	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

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

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UNIT CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2008	2007	2006
		(In thousands)	
OPERATING ACTIVITIES:			
Net income	$ 143,625	$ 266,258	$ 312,177
Adjustments to reconcile net income to net cash provided (used) by operating activities:			
Depreciation, depletion and amortization	244,912	196,111	167,066
Impairment of oil and natural gas properties (Note 2)	281,966		
Unrealized gain on derivatives	(1,302)		
(Gain) loss on disposition of assets	725	(185)	(1,275)
Deferred tax expense	41,077	80,511	63,267
Employee stock compensation plans	15,863	9,254	6,785
Bad debt expense	1,543	1,750	
Plugging liability accretion	2,174	1,704	1,492
Other, net	(247)	(92)	30
Changes in operating assets and liabilities increasing (decreasing) cash:			
Accounts receivable	(34,495)	39,042	7,233
Materials and supplies	3,635	5,343	(4,793)
Prepaid expenses and other	(9,996)	(6,926)	(2,128)
Accounts payable	3,685	(7,296)	(32,577)
Accrued liabilities	684	(9,667)	(10,012)
Contract advances	(3,936)	1,764	(563)
Net cash provided by operating activities	689,913	577,571	506,702
INVESTING ACTIVITIES:			
Capital expenditures	(782,434)	(478,950)	(423,428)
Producing property and other acquisitions	(25,727)	(38,500)	(122,915)
Proceeds from disposition of property and equipment	4,735	5,309	6,796
Acquisition of other assets	(2,715)	(192)	(1,176)
Net cash used in investing activities	(806,141)	(512,333)	(540,723)
FINANCING ACTIVITIES:			
Borrowings under line of credit	397,600	175,800	287,300
Payments under line of credit	(318,700)	(229,500)	(258,000)
Proceeds from exercise of stock options	2,507	692	803
Tax benefit from stock options	1,449	267	532
Increase (decrease) in book overdrafts (Note 2)	32,880	(12,010)	3,028
Net cash provided by (used in) financing activities	115,736	(64,751)	33,663
Net increase (decrease) in cash and cash equivalents	(492)	487	(358)
Cash and cash equivalents, beginning of year	1,076	589	947
Cash and cash equivalents, end of year	$ 584	$ 1,076	$ 589
Supplemental disclosure of cash flow information:			
Cash paid during the year for:			
Interest paid (net of capitalized)	$ 1,679	$ 7,135	$ 5,678

Income taxes	$ 45,700	$ 73,417	$ 125,144

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

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. ORGANIZATION

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

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

Contract Drilling. Carried out by our subsidiary, Unit Drilling Company and its 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 natural gas producing provinces of the Oklahoma and Texas areas of the Anadarko and Arkoma Basins, the Texas Gulf Coast, the North Texas Barnett Shale and the Rocky Mountain regions. 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, Louisiana, 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.

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 deter-minable. The costs of uncompleted drilling contracts include expenses incurred to date on

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2008, all of our contracts were daywork contracts of which 24 were multi-well and had durations which ranged from 6 months to three years. These longer term contracts may contain a fixed rate for the duration of the contract or provide for the periodic renegotiation of the rate within a specific range from the existing rate.

Cash Equivalents and Book Overdrafts. We include as cash equivalents all investments with maturities at date of purchase of three months or less which are readily convertible into known amounts of cash. Book overdrafts are checks that have been issued before the end of the period, but not presented to our bank for payment before the end of the period. At December 31, 2008 and 2007, book overdrafts of $48.5 million and $15.6 million were 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 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. During 2006, Chesapeake Operating, Inc. was our largest drilling customer and accounted for approximately 10% of our total contract drilling revenues. During 2006, Eagle Energy Partners I, L.P., ONEOK and ConocoPhillips Company accounted for approximately 17%, 16% and 10% of our oil and natural gas revenues, respectively. During 2006, ONEOK accounted for approximately 77% of our mid-stream revenues. We had a concentration of cash of $3.8 million and $14.4 million at December 31, 2008 and 2007, 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 in our derivative valuation at December 31, 2008 and determined it was immaterial at that time. At February 13, 2009, Bank of Montreal, Bank of Oklahoma, N.A., 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, 2008, the fair values of the net assets (liabilities) we had with each of these counterparties was $33.0 million, $9.1 million, $13.7 million, $0.5 million, $1.0 million and ($0.7) 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

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 impairment was recorded at December 31, 2008.

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 applying an interest method of allocation. 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 at December 31, 2008. In 2006, the carrying amount of goodwill increased by $17.9 million from additional goodwill recorded for the final earn-out due under the SerDrilco Incorporated acquisition. 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. The acquisitions are more fully discussed in Note 3. Goodwill of $8.4 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. Amortization of $4.4 million, $3.3 million and $0.9 million was recorded in 2008, 2007 and 2006, respectively. Accumulated amortization for 2008 and 2007 was $8.6 million and $4.2 million, respectively. Amortization of $3.8 million, $2.6 million, $1.2 million, $1.2 million and $0.7 million is expected to be recorded in 2009, 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

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 $15.3 million, $13.1 million and $10.2 million were capitalized in 2008, 2007 and 2006, respectively. Independent petroleum engineers annually audit our determination of our oil, NGLs and natural gas reserves. The average composite rates used for depreciation, depletion and amortization (DD&A) were $2.50, $2.32 and $2.04 per Mcfe in 2008, 2007 and 2006, 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 unproved properties totaling $160.0 million are excluded from the DD&A calculation.

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

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

Under the full cost rules, at the end of each quarter, we review the carrying value of our oil and natural gas properties. The full cost ceiling is based principally on the estimated future discounted net cash flows from our oil and natural gas properties discounted at 10%. Full cost companies are required to use the unescalated prices in effect as of the end of each fiscal quarter to calculate the discounted future revenues. 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 $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 years ended December 31, 2007 or 2006. After December 31, 2008 commodity prices have continued to decrease and should commodity prices remain below December 31, 2008 levels, an additional write-down of the carrying value of our oil and natural gas properties will be required for the quarter ending March 31, 2009.

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, 2008, which consisted of swaps and collars, covered 40.2 Bcfe and 23.7 Bcfe in 2009 and 2010, respectively. The effect of these cash flow hedges was a $96.0 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 12 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 2008, the contract drilling segment drilled 122 wells for our exploration and production segment. As required by the SEC, the profit received by the contract drilling segment of $27.9 million, $22.7 million and $22.2 million during 2008, 2007 and 2006, 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, general liability, control of well and employee medical benefits. Insured policies for other coverage contain deductibles or

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

retentions per occurrence that range from $5,000 for motor truck cargo liability to $1.0 million for general liability and 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. Statement of Financial Accounting Standard No. 133 (subsequently amended by Financial Accounting Standard No. s 137, 138 and 149), Accounting for Derivative Instruments and Hedging Activities (FAS 133) 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 under FAS 133 must be 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 14 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.

In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with FAS No. 109, Accounting for Income Taxes and 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 adopted the provisions of FIN 48 effective January 1, 2007. We have no unrecognized tax benefits and the adoption of FIN 48 had no effect on our results of operations or financial condition 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, 2008 balancing position to be approximately 3.6 Bcf on under-produced properties

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

and approximately 3.8 Bcf on over-produced properties. We have recorded a receivable of $0.8 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 $3.4 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 use Statement of Financial Accounting Standards No. 123 (revised 2004), *Share-Based Payment*, (FAS 123(R)) to account for stock-based employee compensation. Among other items, FAS 123(R) requires companies to recognize in their 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. For all unvested stock options outstanding as of January 1, 2006, the previously measured but unrecognized compensation expense, based on the fair value on the original grant date, is being recognized in the financial statements over the remaining vesting period. For equity-based compensation awards granted or modified after December 31, 2005, compensation expense, based on the fair value on the date of grant or modification, is recognized in the financial statements over the vesting period. 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.

Fair Value Measurements. In September 2006, the FASB issued Statement No. 157 (FAS 157), Fair Value Measurements, which establishes a framework for measuring fair value and requires additional disclosures about fair value measurements. Beginning January 1, 2008, we partially applied FAS 157 as allowed by FASB Staff Position (FSP) 157-2, which delayed the effective date of FAS 157 for nonfinancial assets and liabilities. As of January 1, 2008, we have applied the provisions of FAS 157 to our financial instruments and the impact was not material. Under FSP 157-2, we began applying FAS 157 to our nonfinancial assets and liabilities beginning January 1, 2009. We do not anticipate the applicability of FAS 157 to our nonfinancial assets and liabilities will have a material impact on our consolidated financial statements

Business Combinations. In December 2007, the FASB issued Statement No. 141R (FAS 141R), Business Combinations, which will require most identifiable assets, liabilities, noncontrolling interest (previously referred to as minority interests) and goodwill acquired in a business combination to be recorded at full fair value. FAS 141R is effective for our year beginning January 1, 2009, and will be applied prospectively. We do not anticipate the adoption of FAS 141R will have a material impact on our consolidated financial statements, absent any material business combination.

Noncontrolling Interests. In December 2007, the FASB issued Statement No. 160 (FAS 160), Noncontrolling Interest in Consolidated Financial Statements an Amendment to ARB No. 51, which requires noncontrolling interests (previously referred to as minority interests) to be reported as a component of equity. FAS 160 is effective for our year beginning January 1, 2009, and will require retroactive adoption of the presentation and disclosure requirements for existing minority interests. Since we currently do not have any noncontrolling interests, this standard does not presently have an impact on us.

Disclosures about Derivative Instruments and Hedging Activities. In March 2008, the FASB issued Statement No. 161 (FAS 161), Disclosures About Derivative Instruments and Hedging Activities an Amendment of FASB Statement 133, which requires enhanced disclosures about how derivative and hedging

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

activities affect our financial position, financial performance and cash flows. FAS 161 became effective for our year beginning January 1, 2009, and will be applied prospectively. This statement will not have a significant impact on us due to it only requiring enhanced disclosures.

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 disclosure requirements 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 upon 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 upon the first-of-month posted price for each month in the prior twelve-month period. The new oil and gas reporting requirements are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009, with early adoption not permitted. We are currently evaluating the impact the new rules may have on our consolidated financial statements.

NOTE 3. ACQUISITIONS

During 2008, we acquired interest in approximately 55,000 undeveloped acres in the Marcellus Shale, located mainly in Pennsylvania for approximately $40.1 million.

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	$ 38,500

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

On October 13, 2006, our oil and natural gas segment completed the acquisition of Brighton Energy, L.L.C., (Brighton) a privately owned oil and natural gas company for approximately $67.0 million. This acquisition involved all of Brighton s oil and natural gas assets (excluding Atoka and Coal counties in Oklahoma). The majority of the acquired reserves are located in the Anadarko Basin of Oklahoma and the onshore Gulf Coast basins of Texas and Louisiana, with additional reserves in Arkansas, Kansas, Montana, North Dakota and Wyoming. This acquisition had an effective date of August 1, 2006 and was included in our statement of income starting in October 2006 with the results for the period from August 1, 2006 through September 30, 2006 included as an adjustment to the purchase price. The $67.0 million paid in this acquisition increased our basis in oil and natural gas properties by $65.4 with the remaining $1.6 million reflecting working capital.

In September 2006, our mid-stream segment closed the acquisition of Berkshire Energy, LLC., a private company for an adjusted purchase price of $21.7 million. The principal assets of the acquired company consist of a natural gas processing plant, a natural gas gathering system with 15 miles of pipeline, three field compressors, two plant compressors and associated customer contracts and relationships. As part of the acquisition, Superior acquired long-term contracts for the gathering and processing of natural gas that will flow through this gathering system, the value of which is reported as an amortizable intangible asset. The capitalized value of these contracts and associated customer relationship will be amortized over an estimated life of 7 years. The purchase had an effective date of July 31, 2006. The financial results of the acquisition were included in the our statement of income from September 1, 2006 forward with the results for the period from August 1, 2006 through August 31, 2006 included as an adjustment to the purchase price. The $21.7 million acquisition price for Berkshire Energy, LLC was allocated as follows (in thousands):

Working capital	$ 337
Processing plant and gathering system	3,422
Amortizable intangible assets	17,957
Total consideration	$ 21,716

On May 16, 2006, we announced that our oil and natural gas segment had closed the acquisition of certain oil and natural gas properties from a group of private entities for approximately $32.4 million in cash. This acquisition had an effective date of April 1, 2006. The $32.4 million paid in this acquisition increased our basis in oil and natural gas properties.

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 4. EARNINGS PER SHARE

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

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the year ended December 31, 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	$ 143,625	46,909	$ 3.06
For the year ended December 31, 2007:			
Basic earnings per common share	$ 266,258	46,366	$ 5.74
Effect of dilutive stock options, restricted stock and SARs		287	(0.03)
Diluted earnings per common share	$ 266,258	46,653	$ 5.71
For the year ended December 31, 2006:			
Basic earnings per common share	$ 312,177	46,228	$ 6.75
Effect of dilutive stock options and restricted stock		223	(0.03)
Diluted earnings per common share	$ 312,177	46,451	$ 6.72

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:

	2008	2007	2006
Options and SARs	84,900	105,655	33,000
Average exercise price	$ 64.39	$ 56.33	$ 61.40

NOTE 5. LONG-TERM DEBT AND OTHER LONG-TERM LIABILITIES

Long-Term Debt

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

2008	2007
(In thousands)	

Revolving credit facility, with interest at December 31, 2008 and 2007 of 3.2% and 6.0%, respectively	$ 199,500	$ 120,600
Less current portion		
Total long-term debt	$ 199,500	$ 120,600

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, 2008, the commitment amount was $325.0 million. We are charged a commitment fee of 0.375 to 0.50 of 1% on

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 2008, which includes the effect of our interest rate swaps, was 4.5%. At December 31, 2008 and February 13, 2009, borrowings were $199.5 million and $193.5 million, respectively.

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 $500.0 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, 2008, $170.0 million of our then outstanding borrowings of $199.5 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, 2008, we were in compliance with the covenants of the Credit Facility.

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Other Long-Term Liabilities

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

	2008	2007
	(In thousands)	
Plugging liability	$ 49,230	$ 33,191
Workers compensation	23,473	22,469
Separation benefit plans	6,435	4,945
Gas balancing liability	3,364	3,364
Deferred compensation plan	2,030	2,987
Derivative liabilities interest rate swaps	2,516	249
Derivative liabilities commodity hedges	745	57
Retirement agreements	110	722
	87,903	67,984
Less current portion	12,096	8,869
Total other long-term liabilities	$ 75,807	$ 59,115

Estimated annual principle payments under the terms of debt and other long-term liabilities from 2009 through 2013 are $12.1 million, $3.8 million, $13.9 million, $202.5 million and $2.1 million, respectively. 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, 2008 approximates its fair value.

NOTE 6. ASSET RETIREMENT OBLIGATIONS

Under Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations (FAS 143) 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. Under FAS 143, 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 plugging liabilities.

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

	2008	2007
	(In thousands)	
Plugging liability, January 1:	$ 33,191	$ 33,692
Accretion of discount	2,174	1,704
Liability incurred	4,206	2,043
Liability settled	(796)	(1,448)
Revision of estimates (1)	10,455	(2,800)
Plugging liability, December 31:	49,230	33,191
Less current portion	1,113	672

Total long-term plugging liability	$ 48,117	$ 32,519

(1) Plugging liability estimates were revised upward in 2008 due to the increase in the cost of contract services utilized to plug wells over the last year.

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 7. INCOME TAXES

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

	2008	2007 (In thousands)	2006
Income tax expense computed by applying the statutory rate	$ 78,943	$ 144,694	$ 170,890
State income tax, net of federal benefit	4,547	6,155	8,949
Domestic production activities deduction	(2,081)	(3,682)	(3,067)
Statutory depletion and other	545	(14)	(693)
Income tax expense	$ 81,954	$ 147,153	$ 176,079

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

	2008	2007 (In thousands)	2006
Current taxes:			
Federal	$ 38,535	$ 60,557	$ 105,156
State	2,342	6,085	7,656
	40,877	66,642	112,812
Deferred taxes:			
Federal	37,180	74,721	55,474
State	3,897	5,790	7,793
	41,077	80,511	63,267
Total provision	$ 81,954	$ 147,153	$ 176,079

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

	2008	2007
	(In thousands)	
Deferred tax assets:		
Allowance for losses and nondeductible accruals	$ 37,835	$ 28,029
Net operating loss carryforward	2,248	2,593
	40,083	30,622
Deferred tax liability:		

Depreciation, depletion, amortization and impairment	(504,677)	(450,670)
Net deferred tax liability	(464,594)	(420,048)
Current deferred tax asset	12,467	8,835
Non-current deferred tax liability	$ (477,061)	$ (428,883)

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, 2008, we have net operating loss carryforwards of approximately $6.0 million which expire from 2009 to 2021.

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 8. 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 89,910, 83,277 and 46,941 shares of common stock and recognized expense of $5.0 million, $4.8 million and $3.7 million in 2008, 2007 and 2006, 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. Funds set aside in a trust to satisfy our obligation under the Deferral Plan at December 31, 2008, 2007 and 2006 totaled $2.0 million, $3.0 million and $2.5 million, respectively. We recognized payroll expense and recorded a liability at the time of deferral.

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

On December 31, 2008, we amended all three Plans to be in compliance with Section 409A of the Internal Revenue Code of 1986, as amended. The key amendments to the Plans address, among other things, when distributions may be made, the timing of payments, and the circumstances under which employees become eligible to receive benefits. None of the amendments materially increase the benefits, grants or awards issuable under the Plans. We recognized expense of $1.6 million, $1.5 million and $1.1 million in 2008, 2007 and 2006, 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.

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 9. TRANSACTIONS WITH RELATED PARTIES

Unit Petroleum Company serves as the general partner of 14 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 2008, 2007 and 2006) 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:

	2008	2007	2006
		(In thousands)	
Contract drilling	$ 916	$ 729	$ 617
Well supervision and other fees	$ 375	$ 377	$ 297
General and administrative expense reimbursement	$ 584	$ 444	$ 337

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 10. 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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 11. STOCK-BASED COMPENSATION

In 2008, 2007 and 2006, we recognized stock compensation expense for restricted stock awards, stock options and stock settled stock appreciation rights (SARs) of $11.1 million, $4.8 million and $3.1 million, respectively, and capitalized stock compensation cost for oil and natural gas properties of $3.3 million, $1.2 million and $0.7 million, respectively. The tax benefit related to this stock based compensation was $4.1 million, $2.1 million and $0.9 million, respectively. The remaining unrecognized compensation cost related to unvested awards at December 31, 2008 is approximately $15.2 million with $3.6 million of this amount anticipated to be capitalized. The weighted average period of time over which this cost will be recognized is 0.9 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:

	2008	2007	2006
Options granted	28,000	28,000	33,000
Stock appreciation rights		101,236	44,665
Estimated fair value (in millions)	$ 0.7	$ 2.9	$ 2.1
Estimate of stock volatility	0.32	0.33 to 0.44	0.38 to 0.46
Estimated dividend yield	0%	0%	0%
Risk free interest rate	3.00%	3.75 to 5.00%	4.76 to 5.00%
Expected life range based on prior experience (in years)	5	5 to 8	5 to 8
Forfeiture rate	5%	0 to 11%	0 to 5%

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;

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

- 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.

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, 2006		$
Granted	44,665	51.76
Exercised		
Forfeited		
Outstanding at December 31, 2006	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

There were no SARs granted in 2008. The SARs granted in 2007 and 2006 vest in thirds annually with the first vesting period on January 5, 2009 for the 2007 grant and January 1, 2008 for the 2006 grant. The SARs expire after 10 years from the date of the grant. In 2008, 14,891 shares vested and no shares vested in 2007 or 2006. Fair value of SARs at grant date in 2007 and 2006 was $2.3 million and $1.3 million, respectively. The aggregate intrinsic value of the 145,901 shares outstanding subject to vesting at December 31, 2008 was zero with a weighted average remaining contractual term of 8.7 years.

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Number of Shares	Weighted Average Grant Date Price
Nonvested at January 1, 2006		$
Granted	23,381	51.76
Vested		
Forfeited		
Nonvested at December 31, 2006	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

The restricted stock awards vest in periods ranging from one to three years. The fair value of the restricted stock granted in 2008, 2007 and 2006 at the grant date was $1.5 million, $26.3 million and $1.2 million, respectively. The aggregate intrinsic value of the 20,245 shares of restricted stock on their 2008 vesting date was $1.0 million. The aggregate intrinsic value of the 617,148 shares outstanding subject to vesting at December 31, 2008 was $16.5 million with a weighted average remaining life of 1.4 years.

In December 1984, our Board of Directors approved the adoption of an Employee Stock Bonus Plan. Under this plan 330,950 shares of common stock were reserved for issuance. On May 3, 1995, our shareholders approved and amended the plan to increase by 250,000 shares the aggregate number of shares of common stock that could be issued under the plan. Under the terms of the plan, awards were granted to employees in either cash or stock or a combination thereof, and are 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. 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 will be made under this plan.

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2006	38,190	$ 58.30
Granted		
Vested		
Forfeited	(738)	58.30
Nonvested at December 31, 2006	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		$

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, 2006	434,713	$ 24.14
Granted	5,000	55.83
Exercised	(57,563)	15.61
Forfeited	(800)	37.83
Outstanding at December 31, 2006	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

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The fair value of the stock options granted at the grant date under the Stock Option Plan in 2006 was $0.1 million. The total grant date fair value of the 47,070, 68,470 and 67,670 shares vesting in 2008, 2007 and 2006 was $0.8 million, $1.0 million and $1.4 million. The intrinsic value of options exercised in 2008 was $6.4 million. Total cash received from the options exercised in 2008 was $2.0 million.

	Outstanding Options at December 31, 2008		
Exercise Prices	Number of Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price
$16.69 $19.04	50,300	3.2 years	$ 18.17
$21.50 $26.28	62,570	4.9 years	$ 22.88
$34.75 $37.83	111,020	6.0 years	$ 37.71
$53.90 $60.32	4,400	7.3 years	$ 55.21

The aggregate intrinsic value of the 228,290 shares outstanding subject to options at December 31, 2008 was $0.7 million with a weighted average remaining contractual term of 5.1 years.

	Exercisable Options At December 31, 2008	
Exercise Prices	Number of Shares	Weighted Average Exercise Price
$16.69 $19.04	50,300	$ 18.17
$21.50 $22.95	61,770	$ 22.83
$34.83 $37.83	77,920	$ 37.78
$53.90 $60.32	1,400	$ 53.90

Options for 191,390, 267,130 and 224,910 shares were exercisable with weighted average exercise prices of $27.92, $22.97 and $21.34 at December 31, 2008, 2007 and 2006, respectively. The aggregate intrinsic value of shares exercisable at December 31, 2008 was $0.7 million with a weighted average remaining contractual term of 4.9 years.

In February and May 1992, our Board of Directors and shareholders, respectively, approved the Unit Corporation Non-Employee Directors Stock Option Plan. 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 2,500 shares of common stock. In February and May 2000, our Board of Directors and shareholders, respectively, approved the Unit Corporation 2000 Non-Employee Directors Stock Option Plan, which replaced the prior plan. Under the new plan an aggregate of 300,000 shares of common stock may be issued on exercise of the stock options. Commencing with the year 2000 annual meeting, the amount granted increased to 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.

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Activity pertaining to the Directors Plan is as follows:

	Number of Shares	Weighted Average Exercise Price
Outstanding at January 1, 2006	96,000	$ 24.93
Granted	28,000	62.40
Exercised	(3,500)	20.10
Cancelled		
Outstanding at December 31, 2006	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

The total grant date fair value of each 28,000 shares vesting in 2008, 2007 and 2006 was \$0.7 million, \$0.6 million and \$0.7 million, respectively. The intrinsic value of options exercised in 2008 was \$0.7 million. Total cash received from options exercised in 2008 was \$0.5 million.

	Outstanding and Exercisable Options at December 31, 2008		
Exercise Prices	Number of Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price
$6.90	2,500	0.3 years	$ 6.90
$12.19 $17.54	14,000	2.1 years	$ 16.20
$20.10 $20.46	21,000	3.8 years	$ 20.28
$28.23 $39.50	31,500	5.9 years	$ 34.49
$57.63 $73.26	84,000	8.3 years	$ 64.43

Options for 153,000, 142,500 and 120,500 shares were exercisable with weighted average exercise prices of \$46.85, \$39.26 and \$33.78 at December 31, 2008, 2007 and 2006, respectively. The aggregate intrinsic value of the shares outstanding subject to options at December 31, 2008 was \$0.3 million with a weighted average remaining contractual term of 6.5 years.

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 12. DERIVATIVES

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. As of December 31, 2008, we had two outstanding interest rate swaps both of which were cash flow hedges. There was no material amount of ineffectiveness. Our December 31, 2008 balance sheet recognized the fair value of these swaps as current and non-current derivative liabilities and is presented in the following table:

Term		Amount	Fixed Rate	Floating Rate	Fair Value Asset (Liability)
			($ in thousands)		
December 2007	May 2012	$ 15,000	4.53%	3 month LIBOR	$ (1,351)
December 2007	May 2012	$ 15,000	4.16%	3 month LIBOR	(1,165)
					$ (2,516)

Because of these interest rate swaps, interest expense increased by $0.3 million in 2008 and decreased by $0.7 million and $0.5 million in 2007 and 2006, respectively. A loss of $1.6 million, net of tax, is reflected in accumulated other comprehensive income (loss) as of December 31, 2008.

Commodity Derivatives

We have entered into various types of derivative instruments covering a portion of our projected natural gas, oil and natural gas liquids (NGLs) production or processing, as applicable, to reduce our exposure to market price volatility. As of December 31, 2008, 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.

Fractionation Spreads. In our mid-stream segment, we enter into both NGL sales swaps and natural gas purchase swaps, to lock in our fractionation spread for a percentage of our natural gas processed. The fractionation spread 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.

In accordance with FASB Interpretation No. 39, 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, 2008, we recorded the fair value of our commodity derivatives on our balance sheet as

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

current and non-current derivative assets of $52.1 million and $5.2 million, respectively, and current derivative liabilities of $0.7 million. At December 31, 2007, we recorded the fair value of our commodity derivatives on our balance sheet as current derivative assets of $2.0 million and current derivative liabilities of $0.1 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, 2008, we had a gain of $34.9 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 upon the market prices at December 31, 2008, we expect to transfer approximately $31.7 million, net of tax, of the gain included in the balance in accumulated other comprehensive income (loss) to earnings during the next 12 months in the related month of production. All derivative instruments as of December 31, 2008 are expected to mature by December 31, 2010.

Pursuant to FAS 133, certain derivatives do not qualify for designation as cash flow hedges. Currently, we have two basis swaps that do not qualify as cash flow hedges. 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. Following provisions of FAS 133, 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:

	2008	2007	2006
		(In thousands)	
Increases (decreases) in:			
Oil and natural gas revenue:			
Realized gains (losses) on oil and natural gas derivatives	$ (1,010)	$ 2,589	$
Unrealized gains on ineffectiveness of cash flow hedges	255		
Unrealized gains on non-qualifying oil and natural gas derivatives	1,047		
Total increase on oil and natural gas revenues due to derivatives	292	2,589	
Gas gathering and processing revenue (all realized gains (losses))	2,022	(2,078)	
Gas gathering and processing expense (all realized losses)	1,438	1,694	
Impact on pre-tax earnings	$ 876	$ (1,183)	$

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Oil and Natural Gas Segment:

At December 31, 2008, the following cash flow hedges were outstanding:

Term	Sell/ Purch.	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Jan 09 Dec 09	Sell	Crude oil collar	500 Bbl/day	$100.00 put & $156.25 call	WTI NYMEX
Jan 09 Dec 09	Sell	Crude oil swap	2,000 Bbl/day	$51.87	WTI NYMEX
Jan 09 Dec 09	Sell	Natural gas collar	10,000 MMBtu/day	$8.22 put & $10.80 call	IF NYMEX (HH)
Jan 09 Dec 09	Sell	Natural gas swap	30,000 MMBtu/day	$7.01	IF Tenn Zone 0
Jan 09 Dec 09	Sell	Natural gas swap	30,000 MMBtu/day	$6.32	IF CEGT
Jan 09 Dec 09	Sell	Natural gas swap	25,000 MMBtu/day	$5.57	IF PEPL
Jan 10 Dec 10	Sell	Natural gas swap	20,000 MMBtu/day	$6.89	IF Tenn Zone 0
Jan 10 Dec 10	Sell	Natural gas swap	20,000 MMBtu/day	$6.62	IF CEGT
Jan 10 Dec 10	Sell	Natural gas swap	15,000 MMBtu/day	$7.20	IF NYMEX (HH)
Jan 10 Dec 10	Sell	Natural gas swap	10,000 MMBtu/day	$6.25	IF PEPL

At December 31, 2008, the following non-qualifying cash flow derivatives were outstanding:

Term	Sell/ Purch.	Commodity	Hedged Volume	Basis Differential	Hedged Market
Jan 09 Dec 09	Sell	Natural gas basis differential swap	10,000 MMBtu/day	($1.02)	PEPL NYMEX
Jan 09 Dec 09	Sell	Natural gas basis differential swap	10,000 MMBtu/day	($1.10)	CEGT NYMEX

Subsequent to December 31, 2008, the following cash flow hedges were entered into:

Term	Sell/ Purch.	Commodity	Hedged Volume	Weighted Average Basis Differential	Hedged Market
Jan 10 Dec 10	Sell	Natural gas basis differential swap	10,000 MMBtu/day	($0.79)	PEPL NYMEX

NOTE 13. FAIR VALUE MEASUREMENTS

As of January 1, 2008, we applied the provisions of FAS 157, Fair Value Measurements for our financial assets and liabilities measured on a recurring basis. This statement establishes a framework for measuring fair value of assets and liabilities and expands disclosures about fair value measurements. In February 2008, the FASB issued FSP 157-2, which delayed the effective date of FAS 157 by one year for nonfinancial assets and liabilities.

FAS 157 defines fair value 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, i.e., 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.

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 table sets forth our recurring fair value measurements:

	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 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 table is a reconciliation of our level 3 fair value measurements:

	Net Derivatives For the Year Ended December 31, 2008	
	Interest Rate Swaps	Commodity Swaps and Collars
	(In thousands)	
Beginning of period	$ (153)	$ 2,625
Total gains or losses (realized and unrealized):		
Included in earnings (1)	(317)	3,923
Included in other comprehensive income (loss)	(2,363)	54,581
Purchases, issuance and settlements	317	(2,621)
End of period	$ (2,516)	$ 58,508

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, 2008	$	$ 1,302

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

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

We evaluated the non-performance risk with regard to our counterparties in our valuation at December 31, 2008 and determined it was immaterial.

NOTE 14. COMMITMENTS AND CONTINGENCIES

We lease office space or yards in Tulsa and Woodward, Oklahoma; Canadian, Houston and Midland, Texas; Englewood and Denver, Colorado; Pinedale, Wyoming; and Pittsburg, Pennsylvania under the terms of operating leases expiring through January, 2012. We recently closed our offices in Woodward and Midland and our leases expire in March and November 2009, respectively. 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 $2.0 million, $0.5 million and $0.3 million in 2009, 2010 and 2011, respectively. Total rent expense incurred was $2.1 million, $1.7 million and $1.3 million in 2008, 2007 and 2006, 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 $241,000 and $7,000 in 2008 and 2006, 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 $49.4 million of new drilling rig components, drill pipe, drill collars and related equipment, $10.6 million of casing and $4.7 million for a new processing plant. Beyond 2009, we have committed to purchase approximately $14.8 million of new drill pipe and drill collars.

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 15. 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

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	2008	2007 (In thousands)	2006
Revenues:			
Contract drilling	$ 688,196	$ 673,517	$ 741,176
Elimination of inter-segment revenue	65,469	45,875	41,780
Contract drilling net of inter-segment revenue	622,727	627,642	699,396
Oil and natural gas exploration	553,998	391,480	357,599
Gas gathering and processing	237,999	161,679	115,146
Elimination of inter-segment revenue	56,269	23,084	13,283
Gas gathering and processing net of inter-segment revenue	181,730	138,595	101,863
Other	(362)	1,037	3,527
Total revenues	$ 1,358,093	$ 1,158,754	$ 1,162,385
Operating income (loss) (1):			
Contract drilling	$ 239,979	$ 266,058	$ 333,555
Oil and natural gas exploration	(3,757)(7)	166,954	168,355
Gas gathering and processing	16,422	7,760	6,782
Total operating income	252,664	440,772	508,692
General and administrative expense	(25,419)	(22,036)	(18,690)
Interest expense, net	(1,304)	(6,362)	(5,273)
Other income (expense) net	(362)	1,037	3,527
Income before income taxes	$ 225,579	$ 413,411	$ 488,256
Identifiable assets (2):			
Contract drilling	$ 1,009,292	$ 879,784	$ 755,290
Oil and natural gas exploration	1,363,534(7)	1,148,633	979,362
Gas gathering and processing	169,687	148,865	123,500
Total identifiable assets	2,542,513	2,177,282	1,858,152
Corporate assets	39,353	22,537	15,944
Total assets	$ 2,581,866	$ 2,199,819	$ 1,874,096
Capital expenditures:			
Contract drilling	$ 196,229	$ 220,424(3)	$ 170,485(4)
Oil and natural gas exploration	561,548	307,337	350,156(5)
Gas gathering and processing	49,887	34,176	42,942(6)
Other	9,860	2,190	2,566
Total capital expenditures	$ 817,524	$ 564,127	$ 566,149

Depreciation, depletion, amortization and impairment:			
Contract drilling	$ 69,841	$ 56,804	$ 51,959
Oil and natural gas exploration:			
Depreciation, depletion and amortization	159,550	127,417	108,124
Impairment of oil and natural gas properties	281,966(7)		
Gas gathering and processing	14,822	11,059	6,247
Other	699	831	736
Total depreciation, depletion, amortization and impairment	$ 526,878	$ 196,111	$ 167,066

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

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(3) Includes $5.3 million of goodwill from the acquisition in June 2007.

(4) Includes $17.9 million of goodwill from the third and final year of the SerDrilco earn-out agreement.

(5) Includes $10.2 million for capitalized cost relating to plugging liability recorded in 2006.

(6) Includes $18.0 million for capitalized intangibles.

(7) In December 2008, we had an impairment of oil and gas properties of $282.0 million pre-tax ($175.5 million net of tax) due to low commodity prices at year-end.

NOTE 16. 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)			
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	$ (2.56)
2007:				
Revenues	$ 277,271	$ 286,640	$ 286,335	$ 308,508
Gross profit (1)	$ 106,829	$ 108,916	$ 106,509	$ 118,518
Net income	$ 64,482	$ 65,566	$ 64,061	$ 72,149
Net income per common share:				

Basic (2)	$	1.39	$	1.41	$	1.38	$	1.56
Diluted (2)	$	1.39	$	1.41	$	1.37	$	1.55

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

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

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UNIT CORPORATION AND SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS DISCLOSURES

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:

	2008	2007 (In thousands)	2006
Capitalized costs:			
Proved properties	$ 2,090,623	$ 1,624,478	$ 1,330,010
Unproved properties	160,034	64,722	53,687
	2,250,657	1,689,200	1,383,697
Accumulated depreciation, depletion, amortization and impairment	(1,029,617)	(589,029)	(462,310)
Net capitalized costs	$ 1,221,040	$ 1,100,171	$ 921,387
Cost incurred:			
Unproved properties acquired	$ 113,104	$ 33,398	$ 29,262
Proved properties acquired	41,227	1,820	92,278
Exploration	41,474	37,673	26,008
Development	351,876	235,203	192,421
Asset retirement obligation	13,867	(757)	10,187
Total costs incurred	$ 561,548	$ 307,337	$ 350,156

The following table shows a summary of the oil and natural gas property costs not being amortized at December 31, 2008, by the year in which such costs were incurred:

	2008	2007	2006 (In thousands)	2005 and Prior	Total
Undeveloped Leasehold Acquired	$ 109,154	$ 22,283	$ 12,778	$ 15,819	$ 160,034

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:

	2008	2007 (In thousands)	2006
Revenues	$ 545,937	$ 386,231	$ 352,460
Production costs	(102,207)	(84,382)	(70,869)
Depreciation, depletion, amortization and impairment	(440,588)	(126,719)	(107,604)
	3,142	175,130	173,987

Income tax expense	(1,141)	(62,337)	(62,816)
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 2,001	$ 112,793	$ 111,171

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UNIT CORPORATION AND SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)

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 (unaudited):

	Oil Bbls	Liquids Bbls (In thousands)	Natural Gas Mcf
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, discoveries and other additions	2,341	3,179	90,217
Purchases of minerals in place	221	208	11,206
Production	(1,261)	(1,388)	(47,473)
End of Year	9,699	10,171	450,135
Proved developed reserves:			
Beginning of year	7,770	5,133	326,071
End of year	7,508	8,638	355,824
2007:			
Proved developed and undeveloped reserves:			
Beginning of year	9,357	2,226	406,400
Revision of previous estimates (1)	(111)	2,830	(16,382)
Extensions, discoveries and other additions	1,521	1,878	72,642
Purchases of minerals in place			420
Production	(1,091)	(785)	(43,464)
End of Year	9,676	6,149	419,616
Proved developed reserves:			
Beginning of year	7,465	2,042	307,734
End of year	7,770	5,133	326,071
2006:			
Proved developed and undeveloped reserves:			
Beginning of year	8,052	1,819	352,841
Revision of previous estimates	(20)	179	(2,779)
Extensions, discoveries and other additions	1,240	638	71,453
Purchases of minerals in place	1,119	31	29,067
Sales of minerals in place	(22)		(12)
Production	(1,012)	(441)	(44,170)
End of Year	9,357	2,226	406,400
Proved developed reserves:			
Beginning of year	6,763	1,691	269,379
End of year	7,465	2,042	307,734

(1) 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.

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, independent petroleum

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UNIT CORPORATION AND SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)

consultants, to audit our reserves as prepared by our reservoir engineers. The wells or locations for which estimates of reserves were audited were reserves that comprised the top 82% 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, 2008.

Proved oil and gas reserves, as defined in SEC Rule 4-10(a), are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based on future conditions.

Reservoirs are considered proved if economic productibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes:

- that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and

- the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Estimates of proved reserves do not include the following:

- oil that may become available from known reservoirs but is classified separately as indicated additional reserves ;

- crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;

- crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and

- crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved developed oil, NGLs and natural gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved undeveloped oil, NGLs and natural gas reserves are 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 drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should 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 tests in the area and in the same reservoir.

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UNIT CORPORATION AND SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)

Estimates of oil, NGLs and natural gas reserves require extensive judgments of reservoir engineering data as previously explained. 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 year-end prices and costs, and year-end 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 (unaudited):

	2008	2007	2006
		(In thousands)	
Future cash flows	$ 2,694,217	$ 3,890,789	$ 2,749,673
Future production costs	(769,325)	(1,007,681)	(763,677)
Future development costs	(253,941)	(234,415)	(218,749)
Future income tax expenses	(510,361)	(880,560)	(538,720)
Future net cash flows	1,160,590	1,768,133	1,228,527
10% annual discount for estimated timing of cash flows	(536,116)	(777,802)	(543,632)
Standardized measure of discounted future net cash flows relating to proved oil, NGLs and natural gas reserves	$ 624,474	$ 990,331	$ 684,895

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

	2008	2007	2006
		(In thousands)	
Sales and transfers of oil and natural gas produced, net of production costs	$ (443,729)	$ (301,847)	$ (281,591)
Net changes in prices and production costs	(548,683)	344,497	(408,186)
Revisions in quantity estimates and changes in production timing	(34,066)	(155)	(4,190)
Extensions, discoveries and improved recovery, less related costs	229,928	311,529	197,897
Changes in estimated future development costs	20,273	19,971	(10,875)
Previously estimated cost incurred during the period	55,763	49,333	30,112
Purchases of minerals in place	20,797	1,540	65,531
Sales of minerals in place			(399)
Accretion of discount	148,160	98,412	131,290
Net change in income taxes	223,188	(192,045)	149,990
Other net	(37,488)	(25,799)	(48,367)
Net change	(365,857)	305,436	(178,788)
Beginning of year	990,331	684,895	863,683
End of year	$ 624,474	$ 990,331	$ 684,895

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UNIT CORPORATION AND SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)

Our SMOG and changes to it were determined in accordance with Statement of Financial Accounting Standards No. 69. 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.

Future cash flows are computed by applying year-end spot prices of $44.60 per barrel for oil, $26.04 per barrel for NGLs and $5.71 per Mcf for natural gas relating to proved reserves and to the year-end quantities of those reserves. Future price changes are considered only to the extent provided by contractual arrangements in existence at year-end.

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

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

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

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

None.

Item 9A. ***Controls and Procedures***

(a) **Evaluation of Disclosure Controls and Procedures**

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

(b) **Management s Report on Internal Control Over Financial Reporting**

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as that is defined in Exchange Act Rule 13a-15(f). Our management, including our Chief Executive Officer and Chief Financial Officer, conducted an evaluation of the effectiveness of our internal control over financial reporting based on the *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2008.

The effectiveness of the company s internal control over financial reporting as of December 31, 2008, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

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

During the last quarter, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. ***Other Information***

None.

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PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

In accordance with Instruction G(3) of Form 10-K, the information required by this item is incorporated in this report by reference to the Proxy Statement, except for the information regarding our executive officers which is presented below. The Proxy Statement will be filed before our annual shareholders meeting scheduled to be held on May 6, 2009.

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 15, 2008. 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 13, 2009 concerning each of our executive officers as well as certain officers of our subsidiaries. There were no arrangements or understandings between any of the officers and any other person(s) under which the officers were elected.

NAME	AGE	POSITION HELD
Larry D. Pinkston	54	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	51	Senior Vice President since December 2002, General Counsel and Corporate Secretary since January 1987
David T. Merrill	48	Chief Financial Officer and Treasurer since February 24, 2004, Vice President of Finance from August 2003 to February 24, 2004
Brad J. Guidry	53	Senior Vice President, Unit Petroleum Company since March 1, 2005
John Cromling	61	Executive Vice President, Unit Drilling Company since April 15, 2005
Robert Parks	54	A Manager and President, Superior Pipeline Company, L.L.C. since June 1996
Richard E. Heck	48	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.

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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).

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

The following table provides information for all equity compensation plans as of the fiscal year ended December 31, 2008, under which our equity securities were authorized for issuance:

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (c)
Equity compensation plans approved by security holders (1)	344,390(2)	$ 36.33	1,715,972(3)
Equity compensation plans not approved by security holders			
Total	344,390	$ 36.33	1,715,972

(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:

191,390 stock options outstanding under the company s Amended and Restated Stock Option Plan.

153,000 stock options outstanding under the Non-Employee Directors Stock Option Plan.

(3) This number reflects 3,500 shares available for issuance under the Non-Employee Directors Stock Option Plan and 1,712,472 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.

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

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

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

Item 14. ***Principal Accounting Fees and Services***

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

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PART IV

Item 15. ***Exhibits, Financial Statement Schedules***
(a) Financial Statements, Schedules and Exhibits:

1. ***Financial Statements:***
Included in Part II of this report:

Report of Independent Registered Public Accounting Firm
Consolidated Balance Sheets as of December 31, 2008 and 2007
Consolidated Statements of Income for the years ended December 31, 2008, 2007 and 2006
Consolidated Statements of Changes in Shareholders Equity for the years ended December 31, 2006, 2007 and 2008
Consolidated Statements of Cash Flows for the years ended December 31, 2008, 2007 and 2006
Notes to Consolidated Financial Statements

2. ***Financial Statement Schedules:***
Included in Part IV of this report for the years ended December 31, 2008, 2007 and 2006:

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 18, 2005 (filed as Exhibit 4.1 to Unit s Form 8-K dated May 18, 2005, which is incorporated herein by reference).
4.3	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 March 26, 2008 (filed as Exhibit 10.1 to Unit s Form 8-K dated March 31, 2008, 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 Drilling and Exploration Employee Bonus Plan (filed as Exhibit 10.16 to Unit s Registration Statement on Form S-4 as S.E.C. File No. 33-7848, which is incorporated herein by reference).
10.2.4*	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).
10.2.5*	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).
10.2.6*	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).
10.2.7	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).
10.2.8*	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).
10.2.9*	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).
10.2.10*	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).
10.2.11*	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).
10.2.12*	Unit Corporation Special Separation Benefit Plan as amended (filed as Exhibit 10.3 to Unit s Form 8-K dated December 20, 2004).
10.2.13*	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).
10.2.14	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).
10.2.15*	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).

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10.2.16	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).
10.2.17	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).
10.2.18	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).
10.2.19	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).
10.2.20	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).
10.2.21*	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).
10.2.22	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).
10.2.23	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).
10.2.24	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).
10.2.25	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).
10.2.26	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).
10.2.27	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).
10.2.28	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).
10.2.29	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).
10.2.30	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).
10.2.31	Unit 2009 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).

* Indicates a management contract or compensatory plan identified under the requirements of Item 15 of Form 10-K.

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Schedule II

UNIT CORPORATION AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Allowance for Doubtful Accounts:

Description	Balance at Beginning of Period	Additions Charged to Costs & Expenses	Deductions & Net Write-Offs	Balance at End of Period
		(In thousands)		
Year ended December 31, 2008	$ 3,350	$ 1,620	$ 77	$ 4,893
Year ended December 31, 2007	$ 1,600	$ 1,750	$	$ 3,350
Year ended December 31, 2006	$ 1,612	$	$ 12	$ 1,600

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SIGNATURES

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

UNIT CORPORATION

DATE: February 24, 2009

By: /s/ LARRY D. PINKSTON
LARRY D. PINKSTON
President and Chief Executive Officer

(Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on the 24th day of February, 2009.

Name	Title
/s/ JOHN G. NIKKEL **John G. Nikkel**	Chairman of the Board and Director
/s/ LARRY D. PINKSTON **Larry D. Pinkston**	President and Chief Executive Officer, Chief Operating Officer and Director (Principal Executive Officer)
/s/ DAVID T. MERRILL **David T. Merrill**	Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ DON HAYES **Don Hayes**	Controller (Principal Accounting Officer)
/s/ J. MICHAEL ADCOCK **J. Michael Adcock**	Director
/s/ GARY CHRISTOPHER **Gary Christopher**	Director
/s/ STEVEN B. HILDEBRAND **Steven B. Hildebrand**	Director
/s/ KING P. KIRCHNER **King P. Kirchner**	Director
/s/ WILLIAM B. MORGAN	Director

William B. Morgan	
/s/ ROBERT SULLIVAN, JR.	Director
Robert Sullivan, Jr.	
/s/ JOHN H. WILLIAMS	Director
John H. Williams	

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EXHIBIT INDEX

Exhibit No.	Description
10.2.31	Unit 2009 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership.
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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.