UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the
Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): May 3, 2011

Unit Corporation
(Exact name of registrant as specified in its charter)

Delaware	1-9260	73-1283193
(State or other jurisdiction of incorporation)	(Commission File Number)	(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

Not Applicable
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Section 8 - Other Events.

Item 8.01 Other Events.

Unit Corporation (Unit) is filing this Current Report on Form 8-K to provide certain revised audited financial statements at December 31, 2010 and for each of the three years in the period ended December 31, 2010 (attached as Exhibit 99.1) and revised unaudited condensed consolidated interim financial statements at March 31, 2011 and for the three months ended March 31, 2011 (attached as Exhibit 99.2). The financial statements have been revised to include certain disclosures in Note 6 "Long-Term Debt and Other Long-Term Liabilities" described further below.

Unit anticipates filing a registration statement on Form S-3 on or about May 3, 2011. Securities being registered under the registration statement include debt securities guaranteed by some of Unit's wholly-owned subsidiaries. Unit is subject to the requirements of Rule 3-10 of Regulation S-X regarding financial statements of guarantors and issuers of guaranteed securities registered or being registered. As permitted by Note 1 to Rule 3-10(f), Unit is meeting the requirements of this rule by adding a paragraph to Note 6 to the Notes to Consolidated Financial Statements at December 31, 2010 and for each of the three years in the period ended December 31, 2010 and at March 31, 2011 and for the three months ended March 31, 2011. Unit, as the parent company, has no independent assets or operations not otherwise permitted within the scope of Rule 3-10 . The guarantees registered under the registration statement are full and unconditional and joint and several, and any subsidiaries of Unit other than the subsidiary guarantors are minor. There are no significant restrictions on the ability of our parent company to receive funds from our subsidiaries through dividends, loans, advances or otherwise.

This report should be read in conjunction with Unit's Annual Report on Form 10-K for the year ended December 31, 2010 filed February 24, 2011 and Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, as well as Unit's other filings with the SEC.

Section 9 – Financial Statements and Exhibits

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits.

Exhibit No.	Description
23.1	Consent of Independent Registered Public Accounting Firm, PricewaterhouseCoopers LLP.
23.2	Consent of Ryder Scott Company, L.P.
99.1	Item 8 – Financial Statements and Supplementary Data of Annual Report on Form 10-K for the year ended December 31, 2010.
99.2	Item 1 – Financial Statements of Quarterly Report on Form 10-Q for the quarter ended March 31, 2011.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

Unit Corporation

Date: May 3, 2011

By: /s/ Mark E. Schell
Mark E. Schell
Senior Vice President
and General Counsel

EXHIBIT INDEX

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99.2	Item 1 – Financial Statements of Quarterly Report on Form 10-Q for the quarter ended March 31, 2011.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (File No.'s 33-19652, 33-44103, 33-49724, 33-64323, 33-53542, 333-38166, 333-39584, 333-135194, 333-137857 and 333-166605)) of Unit Corporation of our report dated February 24, 2011, except with respect to our opinion on the consolidated financial statements insofar as it relates to guarantor subsidiaries described in Note 6 which is as of May 3, 2011, relating to the consolidated financial statements, financial statement schedule, and the effectiveness of internal control over financial reporting, which appears in this Current Report on Form 8-K.

/s/ PricewaterhouseCoopers LLP

Tulsa, Oklahoma
May 3, 2011

Exhibit 23.2

CONSENT OF RYDER SCOTT COMPANY, L.P.

We hereby consent to incorporation by reference in the Registration Statements on Form S-8 (File Nos. 33-19652, 33-44103, 33-49724, 33-64323, 33-53542, 333-38166, 333-39584, 333-135194, 333-137857 and 333-166605) of Unit Corporation the reference to our audit report for Unit Corporation dated January 19, 2011, which appears in the December 31, 2010 annual report on Form 10-K of Unit Corporation, except to the extent that our report's impact on the consolidated financial statements insofar as it relates to guarantor subsidiaries described in Note 6 which is as of May 3, 2011 which appears in this Current Report on Form 8-K.

/s/ Ryder Scott Company, L.P.

RYDER SCOTT COMPANY, L.P.

Houston, Texas
May 3, 2011

Exhibit 99.1

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

Index to Financial Statements
Unit Corporation and Subsidiaries

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, 2010. 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, 2010, 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, 2010, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Report of Independent Registered Public Accounting Firm

To Board of Directors and Shareholders of Unit Corporation:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, changes in shareholders' equity, and cash flows present fairly, in all material respects, the financial position of Unit Corporation and its subsidiaries at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under item 15(a)(2), presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

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

/s/ PricewaterhouseCoopers LLP

Tulsa, Oklahoma
February 24, 2011, except with respect to our opinion on the consolidated financial statements insofar as it relates to guaranteed subsidiaries discussed in Note 6, as to which the date is May 3, 2011.

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
	2010	2009
	(In thousands except share and par value amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,359	$ 1,140
Restricted cash	0	20
Accounts receivable (less allowance for doubtful accounts of $5,083 and $5,186)	130,142	74,382
Materials and supplies	6,316	6,914
Current derivative asset (Note 13)	5,568	9,945
Current income tax receivable	25,211	15,236
Current deferred tax asset (Note 8)	13,537	14,423
Prepaid expenses and other	6,047	6,035
Total current assets	188,180	128,095
Property and equipment:		
Drilling equipment	1,273,861	1,217,361
Oil and natural gas properties, on the full cost method:		
Proved properties	2,738,093	2,309,193
Undeveloped leasehold not being amortized	175,065	140,129
Gas gathering and processing equipment	199,564	172,549
Transportation equipment	31,688	30,726
Other	28,511	22,747
	4,446,782	3,892,705
Less accumulated depreciation, depletion, amortization and impairment	2,047,031	1,879,112
Net property and equipment	2,399,751	2,013,593
Goodwill (Note 2)	62,808	62,808
Other intangible assets, net	3,022	5,633
Non-current derivative asset (Note 13)	2,537	0
Other assets	12,942	18,270
Total assets	$ 2,669,240	$ 2,228,399
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 89,885	$ 55,880
Accrued liabilities (Note 5)	30,093	34,571
Contract advances	2,582	3,124
Current portion of derivative liabilities (Note 13)	14,446	2,230
Current portion of other long-term liabilities (Note 6)	10,122	9,342
Total current liabilities	147,128	105,147
Long-term debt (Note 6)	163,000	30,000
Long-term derivative liabilities (Note 13)	4,359	1,142
Other long-term liabilities (Note 6)	88,030	79,984
Deferred income taxes (Note 8)	556,106	446,316
Commitments and contingencies (Note 15)		
Shareholders' equity:		
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	0	0
Common stock, $0.20 par value, 175,000,000 shares authorized, 47,910,431 and 47,530,669 shares issued as of December 31, 2010 and 2009, respectively	9,493	9,405
Capital in excess of par value	393,501	383,957
Accumulated other comprehensive income(loss) (net of tax of ($4,243) and $2,757, respectively)	(6,851)	4,458
Retained earnings	1,314,474	1,167,990
Total shareholders' equity	1,710,617	1,565,810

Total liabilities and shareholders’ equity	$ 2,669,240	$ 2,228,399

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2010	2009	2008
	(In thousands except per share amounts)		
Revenues:			
Contract drilling	$ 316,384	$ 236,315	$ 622,727
Oil and natural gas	400,807	357,879	553,998
Gas gathering and processing	154,516	108,628	181,730
Other	10,138	7,076	(362)
Total revenues	881,845	709,898	1,358,093
Expenses:			
Contract drilling:			
Operating costs	186,813	140,080	312,907
Depreciation	69,970	45,326	69,841
Oil and natural gas:			
Operating costs	105,365	87,734	116,239
Depreciation, depletion and amortization	118,793	114,681	159,550
Impairment of oil and natural gas properties (Note 2)	0	281,241	281,966
Gas gathering and processing:			
Operating costs	122,146	87,908	150,466
Depreciation and amortization	15,385	16,104	14,822
General and administrative	26,152	24,011	25,419
Interest, net	0	539	1,304
Total expenses	644,624	797,624	1,132,514
Income (loss) before income taxes	237,221	(87,726)	225,579
Income tax expense (benefit):			
Current	(9,935)	(223)	40,877
Deferred	100,672	(32,003)	41,077
Total income taxes	90,737	(32,226)	81,954
Net income (loss)	$ 146,484	$ (55,500)	$ 143,625
Net income (loss) per common share:			
Basic	$ 3.10	$ (1.18)	$ 3.08
Diluted	$ 3.09	$ (1.18)	$ 3.06

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
Year Ended December 31, 2008, 2009 and 2010

	Common Stock	Capital In Excess of Par Value	Accumulated Other Compre-hensive Income	Retained Earnings	Total
Balances, January 1, 2008	$ 9,280	$ 344,512	$ 1,160	$ 1,079,865	$ 1,434,817
Comprehensive income:					
Net Income	0	0	0	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	0	0	31,816	0	31,816
Reclassification— derivative settlements	0	0	469	0	469
Ineffective portion of derivatives qualifying for cash flow hedge accounting	0	0	(161)	0	(161)
Total comprehensive income	0	0	0	0	175,749
Activity in employee compensation plans (220,875 shares)	45	22,488	0	0	22,533
Balances, December 31, 2008	9,325	367,000	33,284	1,223,490	1,633,099
Comprehensive income (loss):					
Net loss	0	0	0	(55,500)	(55,500)
Other comprehensive income (loss) (net of tax of $20,430, ($37,560), $340):					
Change in value of cash flow derivative instruments used as cash flow hedges	0	0	32,307	0	32,307
Reclassification— derivative settlements	0	0	(61,690)	0	(61,690)
Ineffective portion of derivatives qualifying for cash flow hedge accounting	0	0	557	0	557
Total comprehensive loss	0	0	0	0	(84,326)
Activity in employee compensation plans (274,705 shares)	80	16,957	0	0	17,037
Balances, December 31, 2009	9,405	383,957	4,458	1,167,990	1,565,810
Comprehensive income (loss):					
Net income	0	0	0	146,484	146,484
Other comprehensive income (loss) (net of tax of $13,254, ($19,987), ($267)):					
Change in value of cash flow derivative instruments used as cash flow hedges	0	0	21,392	0	21,392
Reclassification— derivative settlements	0	0	(32,268)	0	(32,268)
Ineffective portion of derivatives qualifying for cash flow hedge accounting	0	0	(433)	0	(433)
Total comprehensive income	0	0	0	0	135,175
Activity in employee compensation plans (379,762 shares)	88	9,544	0	0	9,632
Balances, December 31, 2010	$ 9,493	$ 393,501	$ (6,851)	$ 1,314,474	$ 1,710,617

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2010	2009	2008
		(In thousands)	
OPERATING ACTIVITIES:			
Net income (loss)	$ 146,484	$ (55,500)	$ 143,625
Adjustments to reconcile net income (loss) to net cash provided (used) by operating activities:			
Depreciation, depletion and amortization	205,124	177,166	244,912
Impairment of oil and natural gas properties (Note 2)	0	281,241	281,966
Unrealized (gain) loss on derivatives	(1,036)	1,944	(1,302)
(Gain) loss on disposition of assets	(9,687)	(6,224)	725
Deferred tax expense (benefit)	100,672	(32,003)	41,077
Employee stock compensation plans	10,067	10,708	15,863
Bad debt expense	0	975	1,543
ARO liability accretion	2,937	2,585	2,174
Other, net	(69)	(130)	(247)
Changes in operating assets and liabilities increasing (decreasing) cash:			
Accounts receivable	(58,965)	116,472	(34,495)
Materials and supplies	598	3,009	3,635
Prepaid expenses and other	6,957	(1,525)	(9,996)
Accounts payable	(8,913)	(7,068)	3,685
Accrued liabilities	(3,555)	(1,410)	684
Contract advances	(542)	235	(3,936)
Net cash provided by operating activities	390,072	490,475	689,913
INVESTING ACTIVITIES:			
Capital expenditures	(484,080)	(316,660)	(782,434)
Producing property and other acquisitions	(92,573)	0	(25,727)
Proceeds from disposition of property and equipment	40,048	44,733	4,735
Acquisition of other assets	344	0	(2,715)
Net cash used in investing activities	(536,261)	(271,927)	(806,141)
FINANCING ACTIVITIES:			
Borrowings under line of credit	286,900	95,600	397,600
Payments under line of credit	(153,900)	(265,100)	(318,700)
Proceeds from exercise of stock options	149	282	2,507
Tax (expense) benefit from stock options	40	(252)	1,449
Increase (decrease) in book overdrafts (Note 2)	13,219	(48,522)	32,880
Net cash provided by (used in) financing activities	146,408	(217,992)	115,736
Net increase (decrease) in cash and cash equivalents	219	556	(492)
Cash and cash equivalents, beginning of year	1,140	584	1,076
Cash and cash equivalents, end of year	$ 1,359	$ 1,140	$ 584
Supplemental disclosure of cash flow information:			
Cash paid during the year for:			
Interest paid (net of capitalized)	$ 0	$ 682	$ 1,679
Income taxes	$ 3,143	$ 12,302	$ 45,700
Changes in accounts payable and accrued liabilities related to purchases of property, plant and equipment	$ (29,700)	$ 18,285	$ 7,068

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

Note 1. Organization

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

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

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

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

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

Note 2. Summary of Significant Accounting Policies

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

Certain amounts in the accompanying consolidated financial statements for prior periods have been reclassified to conform to current year presentation.

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

Drilling Contracts. We recognize revenues and expenses generated from “daywork” drilling contracts as the services are performed, since we do not bear the risk of completion of the well. Under “footage” and “turnkey” contracts, we bear the risk of completion of the well; therefore, revenues and expenses are recognized when the well is substantially completed. Under this method, substantial completion is determined when the well bore reaches the negotiated depth as stated in the contract. The entire amount of a loss, if any, is recorded when the loss is deter-minable. The costs of uncompleted drilling contracts include expenses incurred to date on “footage” or “turnkey” contracts, which are still in process at the end of the period, and are included in other current assets. Typically, any one of these three types of contracts can be used for the drilling of one well which can take from 20 to 90 days. At December 31, 2010, substantially all of our contracts were daywork contracts of which 38 were multi-well and had durations which ranged from six months to two years. These 38 contracts do not include the five term contracts for the new drilling rigs we are adding in 2011. These longer term contracts may contain a fixed rate for the duration of the contract or provide for the periodic renegotiation of the rate within a specific range from the existing rate.

Cash Equivalents and Book Overdrafts. We include as cash equivalents all investments with maturities at date of purchase of three months or less which are readily convertible into known amounts of cash. Book overdrafts are checks that have been issued before the end of the period, but not presented to our bank for payment before the end of the period. At December 31, 2009 we did not have any book overdrafts and at December 31, 2010, book overdrafts were $13.1 million and included in accounts payable.

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

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

	2010	2009 (In thousands)	2008
Drilling:			
QEP Resources, Inc.	28%	35%	19%
Mid-stream:			
ONEOK	53%	52%	79%
Gavilon	12%	0%	0%
ConocoPhillips	12%	15%	0%
Tenaska	7%	17%	0%

There was not a third party customer that accounted for more than 10% of our oil and natural gas revenues during 2010, 2009 or 2008.

We had a concentration of cash of $23.8 million and $35.0 million at December 31, 2010 and 2009, respectively with one bank.

The use of derivative transactions also involves the risk that the counterparties will be unable to meet the financial terms of the transactions. We considered this non-performance risk with regard to our counterparties and our own non-performance risk in our derivative valuation at December 31, 2010 and determined there was no material risk at that time. At December 31, 2010, the fair values of the net assets (liabilities) we had with each of the counterparties with respect to all of our commodity derivative transactions are listed in the table below:

	December 31, 2010 (In millions)
Bank of Montreal	$ 7.4
Bank of America, N.A.	(0.3)
Crédit Agricole Corporate and Investment Bank, London Branch	(8.5)
Comerica Bank	(5.6)
BBVA Compass Bank	(2.3)
Barclays Capital	0.1
BNP Paribas	0.2
ConocoPhillips	(0.1)
Total	$ (9.1)

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

Realization of the carrying value of property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset including disposal value if any, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. An estimate of fair value is based on the best information available, including prices for similar assets. Changes in such estimates could cause us to reduce the carrying value of property and equipment. No significant impairments were recorded at December 31, 2010, 2009 or 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 accreting an interest charge. This amount is recognized as an increase in the carrying amount of the liability and as a corresponding accretion expense.

Goodwill. Goodwill represents the excess of the cost of acquisitions over the fair value of the net assets acquired. Goodwill is not amortized, but an impairment test is performed at least annually to determine whether the fair value has decreased and is performed additionally when events indicate an impairment may have occurred. Goodwill is all related to our contract drilling segment, and accordingly, the impairment test is generally based on the estimated discounted future net cash flows of our drilling segment, utilizing discount rates and other factors in determining the fair value of our drilling segment. No goodwill impairment was recorded for the years ended December 31, 2010, 2009, or 2008. There were no additions to goodwill in 2010, 2009 or 2008. Goodwill of $6.5 million is deductible for tax purposes.

***Intangible Assets*.** Intangible assets are capitalized and amortized over the estimated period benefited. Such amounts are reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. No intangible asset impairment was recorded for the years ended December 31, 2010 or 2009. Amortization of $2.6 million, $3.7 million and $4.4 million was recorded in 2010, 2009 and 2008, respectively. Accumulated amortization for 2010 and 2009 was $14.9 million and $12.3 million, respectively. Amortization of $1.2 million, $1.2 million and $0.7 million is expected to be recorded in 2011, 2012 and 2013, respectively.

Oil and Natural Gas Operations. We account for our oil and natural gas exploration and development activities using the full cost method of accounting prescribed by the SEC. Accordingly, all productive and non-productive costs incurred in connection with the acquisition, exploration and development of our oil and natural gas reserves, including directly related overhead costs and related asset retirement costs, are capitalized and amortized on a units-of-production method based on proved oil and natural gas reserves. Directly related overhead costs of $13.4 million, $13.2 million and $15.3 million were capitalized in 2010, 2009 and 2008, respectively. Independent petroleum engineers annually audit our internal evaluation of our reserves. The average rates used for depreciation, depletion and amortization (DD&A) were $1.99, $1.87 and $2.50 per Mcfe in 2010, 2009 and 2008, respectively. The calculation of DD&A includes estimated future expenditures to be incurred in developing proved reserves and estimated dismantlement and abandonment costs, net of estimated salvage values. Our undeveloped leasehold properties totaling $175.1 million are excluded from the DD&A calculation.

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

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

Under the full cost rules, at the end of each quarter, we review the carrying value of our oil and natural gas properties. The full cost ceiling is based principally on the estimated future discounted net cash flows from our oil and natural gas properties discounted at 10%. Starting December 31, 2009, companies using full cost accounting moved from using the commodity prices existing on the last day of the period to that of the unweighted arithmetic average of the commodity prices existing on the first day of each of the 12 months before the end of the reporting period to calculate discounted future revenues, unless prices were otherwise determined under contractual arrangements. In the event the unamortized cost of oil and natural gas properties being amortized exceeds the full cost ceiling, as defined by the SEC, the excess is charged to expense in the period during which such excess occurs, even if prices are depressed for only a short period of time. Once incurred, a write-down of oil and natural gas properties is not reversible.

We recorded a non-cash ceiling test write down of $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. Derivative instruments qualifying as cash flow hedges were included in determining the limitation on the capitalized costs in our December 31, 2008 ceiling test calculation. The effect of including those hedges was a $96.0 million pre-tax increase in the discounted net cash flow of our oil and natural gas properties. Our qualifying cash flow hedges as of December 31, 2008, which consisted of swaps and collars, covered 2009 production of 40.2 Billion cubic feet of natural gas equivalent (Bcfe) and 2010 production of 23.7 Bcfe.

We recorded a non-cash ceiling test write-down of $281.2 million pre-tax ($175.1 million, net of tax) during the quarter ending March 31, 2009. This write-down resulted from the reduction in commodity prices existing at the end of the first quarter of 2009 as compared to at the end of 2008. Derivative instruments qualifying as cash flow hedges were included in determining the limitation on the capitalized costs in our March 31, 2009 ceiling test calculation. The effect of including those hedges was a $197.9 million pre-tax increase in the discounted net cash flow of our oil and natural gas properties. Our qualifying cash flow hedges as of March 31, 2009, which consisted of swaps and collars, covered 2009 production of 30.3 Bcfe and 2010 production of 33.2 Bcfe.

At December 31, 2010, using the existing 12-month average commodity prices, including the discounted value of our commodity hedges, we were not required to record a ceiling test write-down. However, if there are declines in the 12-month average prices, including the discounted value of our commodity hedges, we may be required to record a write-down in future periods. Our qualifying cash flow hedges used in the ceiling test determination as of December 31, 2010, consisted of swaps and collars covering 26.3 Bcfe in 2011 and 8.8 Bcfe in 2012. The effect of those hedges on the December 31, 2010 ceiling test was a $22.8 million pre-tax increase in the discounted net cash flows of our oil and natural gas properties. Even without the impact of those hedges, we would not have been required to take a write-down for the quarter. Our oil and natural gas hedging is discussed in Note 13 of the Notes to our Consolidated Financial Statements.

Our contract drilling segment provides drilling services for our exploration and production segment. Depending on their timing some of the drilling services performed on our properties are also deemed to be associated with the acquisition of an ownership interest in the property. Revenues and expenses for such services are eliminated in our income statement, with any profit recognized as a reduction in our investment in our oil and natural gas properties. The contracts for these services are issued under the same conditions and rates as the contracts entered into with unrelated third parties. We eliminated revenue of $40.1 million, $15.0 million and $65.5 million for 2010, 2009 and 2008, respectively from our contract drilling segment and eliminated the associated operating expense of $31.0 million, $13.7 million and $37.6 million during 2010, 2009 and 2008, respectively, yielding $9.1 million, $1.3 million and $27.9 million during 2010, 2009 and 2008, respectively, as a reduction to the carrying value of our oil and natural gas properties.

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

Insurance. We are self-insured for certain losses relating to workers' compensation, control of well and employee medical benefits. Insured policies for other coverage contain deductibles or retentions per occurrence that range from $50,000 for fiduciary liability to $1.0 million for drilling rig physical damage. We have purchased stop-loss coverage in order to limit, to the extent feasible, per occurrence and aggregate exposure to certain types of claims. However, there is no assurance that the insurance coverage will adequately protect us against liability from all potential consequences. We have elected to use an ERISA governed occupational injury benefit plan to cover all Texas drilling operations in lieu of covering them under Texas Workers' Compensation. If insurance coverage becomes more expensive, we may choose to self-insure, decrease our limits, raise our deductibles or any combination of these rather than pay higher premiums.

Hedging Activities. All derivatives are recognized on the balance sheet and measured at fair value. If a derivative is designated as a cash flow hedge, we measure the effectiveness of the hedge, or the degree that the gain (loss) for the hedging instrument offsets the loss (gain) on the hedged item, at each reporting period. The effective portion of the gain (loss) on the derivative instrument is recognized in other comprehensive income as a component of equity and subsequently reclassified into earnings when the forecasted transaction affects earnings. The ineffective portion of a derivative's change in fair value is required to be recognized in earnings immediately. Derivatives that do not qualify for hedge treatment are recorded at fair value with gains (losses) recognized in earnings in the period of change.

We document our risk management strategy and hedge effectiveness at the inception of and during the term of each hedge.

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

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

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

Natural Gas Balancing. We use the sales method for recording natural gas sales. This method allows for recognition of revenue, which may be more or less than its share of pro-rata production from certain wells. We estimate our December 31, 2010 balancing position to be approximately 3.0 Bcf on under-produced properties and approximately 3.2 Bcf on over-produced properties. We have recorded a receivable of $1.5 million on certain wells where we estimate that insufficient reserves are available for us to recover the under-production from future production volumes. We have also recorded a liability of $3.3 million on certain properties where we believe there are insufficient reserves available to allow the under-produced owners to recover their under-production from future production volumes. Our policy is to expense the pro-rata share of lease operating costs from all wells as incurred. Such expenses relating to the balancing position on wells in which we have imbalances are not material.

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

Impact of Financial Accounting Pronouncements.

Improving Disclosures about Fair Value Measurements. In January 2010, the FASB issued ASU 2010-06 – *Fair Value Measurements and Disclosures (ASC 820): Improving Disclosures about Fair Value Measurements* , which provides additional guidance to improve disclosures regarding fair value measurements. The ASU amends ASC 820-10, *Fair Value Measurements and Disclosures—Overall* (formerly FAS 157, *Fair Value Measurements)* to add two new disclosures: (1) transfers in and out of Level 1 and 2 measurements and the reasons for the transfers, and (2) a gross presentation of activity within the Level 3 roll forward. The ASU also includes clarifications to existing disclosure requirements on the level of disaggregation and disclosures regarding inputs and valuation techniques. The ASU applies to all entities required to make disclosures about recurring and nonrecurring fair value measurements. The effective date of the ASU is the first interim or annual reporting period beginning after December 15, 2009 and was adopted January 1, 2010, except for the gross presentation of the Level 3 roll forward information, which is required for annual reporting periods beginning after December 15, 2010 and for interim reporting periods within those years. This statement did not and 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 rules also require companies to report the independence and qualifications of the auditor of the reserve estimates and file reports when a third party is relied on to prepare reserves estimates. The new rules also require that oil and gas reserves be reported and the full cost ceiling value calculated using an average price based on the first-of-month posted price for each month in the prior 12-month period. On January 5, 2010, the FASB issued Accounting Standards update (ASU) 2010-03 - *Extractive Activities - Oil and Gas (ASC 932): Oil and Gas Reserve Estimation and Disclosures* , an update of ASC 932 *Extractive Activities - Oil and Gas* , which subsequently aligns the reserve estimation, disclosure requirements, and definitions of ASC 932 with the disclosure requirements of the new rules issued by the SEC. The new oil and gas reserve measurement and reporting requirements were adopted for oil and gas reserves as of December 31, 2009. For accounting purposes, the new requirements constitute a change in accounting principle inseparable from a change in estimate. As such, prior reserve disclosures were not modified and the impact of the new requirements on our oil and gas reserves was reflected as a change in estimate.

Note 3. Acquisitions

On June 2, 2010, we completed an acquisition of oil and natural gas properties from certain unaffiliated third parties in an effort to explore and develop more oil rich plays. The properties were purchased for approximately $73.7 million in cash, after post close adjustments. The purchase price allocation was $48.7 million for proved properties and $25.0 million for undeveloped leasehold not being amortized. The acquisition included approximately 45,000 net leasehold acres and 10 producing oil wells and is focused on the Marmaton horizontal oil play located mainly in Beaver County, Oklahoma. Proved developed producing net reserves associated with the 10 acquired producing wells is approximately 762,000 BOE — consisting of 511,000 barrels of oil, 155,000 barrels of NGLs and 573 MMcf of natural gas.

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

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

Note 4. Earnings (Loss) Per Share

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

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the year ended December 31, 2010:			
Basic earnings per common share	$ 146,484	47,278	$ 3.10
Effect of dilutive stock options, restricted stock and SARs	0	176	(0.01)
Diluted earnings per common share	$ 146,484	47,454	$ 3.09
For the year ended December 31, 2009:			
Basic earnings (loss) per common share	$ (55,500)	46,990	$ (1.18)
Effect of dilutive stock options, restricted stock and SARs	0	0	0
Diluted earnings (loss) per common share	$ (55,500)	46,990	$ (1.18)
For the year ended December 31, 2008:			
Basic earnings per common share	$ 143,625	46,586	$ 3.08
Effect of dilutive stock options and restricted stock	0	323	(0.02)
Diluted earnings per common share	$ 143,625	46,909	$ 3.06

Due to the net loss for 2009, approximately 373,000 weighted average shares related to stock options, restricted stock and SARs were antidilutive and were excluded from the earnings per share calculation above. The following options and their average exercise prices were not included in the computation of diluted earnings per share because the option exercise prices were greater than the average market price of our common stock for the years ended December 31:

	2010	2009	2008
Options and SARs	222,901	358,821	84,900
Average exercise price	$ 52.59	$ 47.83	$ 64.39

Note 5. Accrued Liabilities

Accrued liabilities consisted of the following as of December 31:

	2010	2009
	(In thousands)	
Employee costs	$ 16,499	$ 13,307
Lease operating expenses	6,214	6,244
Taxes	1,310	5,085
Hedge settlements	1,634	2,503
Other	4,436	7,432
Total accrued liabilities	$ 30,093	$ 34,571

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

Long-Term Debt

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

	2010	2009
	(In thousands)	
Revolving credit facility, with interest, including the effect of hedging, at December 31, 2010 and 2009 of 3.5% and 4.3%, respectively	$ 163,000	$ 30,000
Less current portion	0	0
Total long-term debt	$ 163,000	$ 30,000

Our Credit Facility has a maximum credit amount of $400.0 million and matures on May 24, 2012. The lenders' commitment under the Credit Facility is $325.0 million. Our borrowings are limited to the commitment amount that we elect. As of September 30, 2010, the commitment amount was $325.0 million. We are charged a commitment fee ranging from 0.375 to 0.50 of 1% on the amount available but not borrowed. The rate varies based on the amount borrowed as a percentage of the amount of the total borrowing base. To date we have paid $1.2 million in origination, agency and syndication fees under the Credit Facility. We are amortizing these fees over the life of the agreement.

The lenders' aggregate commitment is limited to the lesser of the amount 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 segment. The October 1, 2010 redetermination maintained the borrowing base at $500.0 million. We or the lenders may request a onetime special redetermination of the amount of the borrowing base between each scheduled redetermination. In addition, we may request a redetermination following the completion of an acquisition that meets the requirements set forth in the Credit 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 period. During any LIBOR funding period, the outstanding principal balance of the promissory note to which the LIBOR option applies may be repaid after three days prior notice to the administrative agent and on payment of any applicable funding indemnification amounts. LIBOR interest is computed as the sum of the LIBOR base for the applicable term plus 1.75% to 2.50% depending on the level of debt as a percentage of the borrowing base and is payable at the end of each term, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the BOK Financial Corporation (BOKF) National Prime Rate, which cannot be less than LIBOR plus 1.00%, and is payable at the end of each month and the principal borrowed may be paid at any time, in part or in whole, without a premium or penalty. At December 31, 2010, $160.0 million of our $163.0 million in outstanding borrowings 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 2010, we were in compliance with our Credit Facility's covenants.

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, 2010 approximates its fair value.

At December 31, 2010, the carrying values on the consolidated balance sheets for cash and cash equivalents, accounts receivable, accounts payable, other current assets and current liabilities approximate their fair value because of their short term nature.

Securities being registered under the registration statement are debt securities guaranteed by our wholly-owned domestic direct and indirect subsidiaries. Unit Corporation (Unit), as the parent company, has no independent assets or operations. The guarantees registered under the registration statement are full and unconditional and joint and several, and subsidiaries of Unit other than the subsidiary guarantors are minor. There are no significant restrictions on the ability of our parent company to receive funds from our subsidiaries through dividends, loans, advances or otherwise.

Other Long-Term Liabilities

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

	2010	2009
	(In thousands)	
ARO liability	$ 69,265	$ 56,404
Workers' compensation	17,566	22,974
Separation benefit plans	5,690	4,681
Gas balancing liability	3,263	3,263
Deferred compensation plan	2,368	2,004
	98,152	89,326
Less current portion	10,122	9,342
Total other long-term liabilities	$ 88,030	$ 79,984

Estimated annual principle payments under the terms of debt and other long-term liabilities from 2011 through 2015 are $10.1 million, $165.9 million, $14.0 million, $2.5 million and $2.7 million, respectively.

Note 7. Asset Retirement Obligations

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

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

	2010	2009
	(In thousands)	
ARO liability, January 1:	$ 56,404	$ 49,230
Accretion of discount	2,937	2,585
Liability incurred	4,768	3,447
Liability settled	(763)	(1,331)
Revision of estimates[(1)]	5,919	2,473
ARO liability, December 31:	69,265	56,404
Less current portion	1,915	1,080
Total long-term ARO liability	$ 67,350	$ 55,324

(1) ARO liability estimates were revised upward in 2010 and 2009 due to the increase in the cost of contract services utilized to plug wells over the preceding years.

Note 8. Income Taxes

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

	2010	2009	2008
		(In thousands)	
Income tax expense (benefit) computed by applying the statutory rate	$ 83,027	$ (30,704)	$ 78,943
State income tax, net of federal benefit	6,030	(2,409)	4,547
Domestic production activities deduction	0	0	(2,081)
Statutory depletion and other	1,680	887	545
Income tax expense (benefit)	$ 90,737	$ (32,226)	$ 81,954

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

	2010	2009	2008
		(In thousands)	
Current taxes:			
Federal	$ (6,856)	$ (5,124)	$ 38,535
State	(3,079)	4,901	2,342
	(9,935)	(223)	40,877
Deferred taxes:			
Federal	88,021	(23,510)	37,180
State	12,651	(8,493)	3,897
	100,672	(32,003)	41,077
Total provision	$ 90,737	$ (32,226)	$ 81,954

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

	2010	2009
	(In thousands)	
Deferred tax assets:		
Allowance for losses and nondeductible accruals	$ 47,742	$ 41,882
Net operating loss carryforward	2,926	2,941
Alternative minimum tax credit carryforward	0	8,857
	50,668	53,680
Deferred tax liability:		
Depreciation, depletion, amortization and impairment	(593,237)	(485,573)
Net deferred tax liability	(542,569)	(431,893)
Current deferred tax asset	13,537	14,423
Non-current—deferred tax liability	$ (556,106)	$ (446,316)

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, 2010, we have net operating loss carryforwards of approximately $5.4 million which expire from 2015 to 2021.

Note 9. Employee Benefit Plans

Under our 401(k) Employee Thrift Plan, employees who meet specified service requirements may contribute a percentage of their total compensation, up to a specified maximum, to the plan. We may match each employee’s contribution, up to a specified maximum, in full or on a partial basis. We made discretionary contributions under the plan of 74,205, 202,655 and 89,910 shares of common stock and recognized expense of $3.6 million, $3.6 million and $5.0 million in 2010, 2009 and 2008, respectively.

We provide a salary deferral plan (Deferral Plan) which allows participants to defer the recognition of salary for income tax purposes until actual distribution of benefits which occurs at either termination of employment, death or certain defined unforeseeable emergency hardships. The liability recorded under the Deferral Plan at December 31, 2010 and 2009 was $2.4 million and $2.0 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 $1.6 million in 2010, 2009 and 2008, respectively, for benefits associated with anticipated payments from these separation plans.

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

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

Note 10. Transactions with Related Parties

Unit Petroleum Company serves as the general partner of 16 oil and gas limited partnerships. Three were formed for investment by third parties and 12 (the employee partnerships) were formed to allow certain of our qualified employees and our directors to participate in Unit Petroleum's oil and gas exploration and production operations. The partnerships for the third party investments were formed in 1984 and 1986. Employee partnerships have been formed for each year beginning with 1984. 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 2010, 2009 and 2008) 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:

	2010	2009	2008
		(In thousands)	
Contract drilling	$ 529	$ 368	$ 916
Well supervision and other fees	$ 386	$ 352	$ 375
General and administrative expense reimbursement	$ 536	$ 376	$ 584

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

Note 11. Shareholder Rights Plan

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

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

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

Note 12. Stock-Based Compensation

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

	2010	2009	2008
		(In millions)	
Recognized stock compensation expense	$ 10.8	$ 9.2	$ 11.1
Capitalized stock compensation cost for our oil and natural gas properties	2.7	2.1	3.3
Tax benefit on stock based compensation	4.1	2.6	4.1

The remaining unrecognized compensation cost related to unvested awards at December 31, 2010 is approximately $9.2 million with $1.9 million of this amount anticipated to be capitalized. The weighted average period of time over which this cost will be recognized is 0.8 years.

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

	2010	2009	2008
Options granted [1]	52,504	3,496	28,000
Stock appreciation rights	0	0	0
Estimated fair value (in millions)	$ 0.8	$ 0.1	$ 0.7
Estimate of stock volatility	0.45	0.41	0.32
Estimated dividend yield	0%	0%	0%
Risk free interest rate	2%	2%	3%
Expected life range based on prior experience (in years)	5	5	5
Forfeiture rate	0%	5%	5%

(1) On May 29, 2009, eight of our directors were each awarded 3,063 options contingent on shareholder approval which was received at the May 5, 2010 annual shareholder's meeting. These 24,504 options granted and vested simultaneously with that approval. On May 6, 2010, eight of our directors each received 3,500 options which vested on November 6, 2010.

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

At our annual meeting on May 3, 2006, our shareholders approved the Unit Corporation Stock and Incentive Compensation Plan. This plan allows for the issuance of 2.5 million shares of common stock with 2.0 million shares being the maximum number of shares that can be issued as "incentive stock options." Awards under this plan may be granted in any one or a combination of the following:

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

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

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

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

	Number of Shares	Weighted Average Grant Date Price
Outstanding at January 1, 2008	145,901	$ 46.59
Granted	0	0
Exercised	0	0
Forfeited	0	0
Outstanding at December 31, 2008	145,901	46.59
Granted	0	0
Exercised	0	0
Forfeited	0	0
Outstanding at December 31, 2009	145,901	46.59
Granted	0	0
Exercised	0	0
Forfeited	0	0
Outstanding at December 31, 2010	145,901	$ 46.59

There were no SARs granted in 2010, 2009 or 2008. The SARs expire after 10 years from the date of the grant. In 2010, 2009 and 2008, 48,632, 48,633 and 14,891 shares vested. The aggregate intrinsic value of the 145,901 shares outstanding subject to vesting at December 31, 2010 was zero with a weighted average remaining contractual term of 6.7 years.

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

	Number of Shares	Weighted Average Grant Date Price
Nonvested at January 1, 2008	636,054	$ 47.09
Granted	30,855	55.44
Vested	(20,245)	50.38
Forfeited	(29,516)	47.19
Nonvested at December 31, 2008	617,148	47.40
Granted	0	0
Vested	(68,836)	46.18
Forfeited	(41,241)	48.69
Nonvested at December 31, 2009	507,071	47.46
Granted	450,355	41.09
Vested	(496,497)	47.09
Forfeited	(14,804)	44.25
Nonvested at December 31, 2010	446,125	$ 47.39

The restricted stock awards vest in periods ranging from one to three years. The fair value of the restricted stock granted in 2010 and 2008 at the grant date was $16.9 million and $1.5 million, respectively. There was no restricted stock granted in 2009. The aggregate intrinsic value of the 496,497 shares of restricted stock on their 2010 vesting date was $18.3 million. The aggregate intrinsic value of the 446,125 shares outstanding subject to vesting at December 31, 2010 was $20.7 million with a weighted average remaining life of 1.2 years.

As a result of the approval of the adoption of the Unit Corporation Stock and Incentive Compensation Plan at our shareholders' annual meeting on May 3, 2006, no further grants were made under the prior Employee Stock Bonus Plan. Under the terms of the old plan, awards were granted to employees in either cash or stock or a combination thereof, and were payable in a lump sum or in installments subject to certain restrictions. On December

13, 2005, 38,190 shares (in the form of restricted stock awards) were granted under the plan one half of which was distributed on January 1, 2007 and the other half was distributed on January 1, 2008. No shares vested in 2006.

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

	Number of Shares	Weighted Average Grant Date Price
Nonvested at January 1, 2008	18,374	$ 58.30
Granted	0	0
Vested	(18,374)	58.30
Forfeited	0	0
Nonvested at December 31, 2008	0	0
Granted	0	0
Vested	0	0
Forfeited	0	0
Nonvested at December 31, 2009	0	0
Granted	0	0
Vested	0	0
Forfeited	0	0
Nonvested at December 31, 2010	0	$ 0

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, 2008	354,500	$ 25.96
Granted	0	0
Exercised	(122,810)	18.75
Forfeited	(3,400)	35.20
Outstanding at December 31, 2008	228,290	29.68
Granted	0	0
Exercised	(4,065)	23.45
Forfeited	(4,600)	38.60
Outstanding at December 31, 2009	219,625	29.61
Granted	0	0
Exercised	(32,360)	20.35
Forfeited	(2,500)	37.83
Outstanding at December 31, 2010	184,765	$ 31.11

The total grant date fair value of the 6,200, 27,100 and 47,070 shares vesting in 2010, 2009 and 2008 was $0.2 million, $1.0 million and $0.8 million. The intrinsic value of options exercised in 2010 was $0.8 million. Total cash received from the options exercised in 2010 was $0.3 million.

Exercise Prices	Outstanding Options at December 31, 2010 Number of Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price
$16.69 - $19.04	26,600	2.0 years	$ 19.04
$21.50 - $26.28	52,645	2.9 years	$ 22.81
$34.75 - $37.83	102,020	4.0 years	$ 37.75
$53.90	3,500	5.2 years	$ 53.90

The aggregate intrinsic value of the 184,765 shares outstanding subject to options at December 31, 2010 was $2.9 million with a weighted average remaining contractual term of 3.4 years.

Exercise Prices	Exercisable Options At December 31, 2010 Number of Shares	Weighted Average Exercise Price
$19.04	26,600	$ 19.04
$21.50 - $22.95	52,645	$ 22.81
$36.42 - $37.83	102,020	$ 37.75
$53.90	2,800	$ 53.90

Options for 184,065, 212,725 and 191,390 shares were exercisable with weighted average exercise prices of $31.02, $29.25 and $27.92 at December 31, 2010, 2009 and 2008, respectively. The aggregate intrinsic value of shares exercisable at December 31, 2010 was $2.9 million with a weighted average remaining contractual term of 3.4 years.

On May 29, 2009, the compensation committee and board of directors, approved amendments to the existing Unit Corporation 2000 Non-Employee Directors' Stock Option Plan. The amendments extended the plan term from May 30, 2010 to May 30, 2017, and increased the aggregate number of shares that may be issued or delivered due to exercise of non-employee director option awards from 210,000 shares of common stock to 510,000 shares of common stock. Under the plan, on the first business day following each annual meeting of shareholders, each person who was then a member of our Board of Directors and who was not then an employee of the company or any of its subsidiaries was granted an option to purchase 3,500 shares of common stock. The option price for each stock option is the fair market value of the common stock on the date the stock options are granted. The term of each option is 10 years and cannot be increased and no stock options may be exercised during the first six months of its term except in case of death.

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

Activity pertaining to the Directors' Plan is as follows:

	Number of Shares	Weighted Average Exercise Price
Outstanding at January 1, 2008	142,500	$ 39.26
Granted	28,000	73.26
Exercised	(17,500)	27.30
Outstanding at December 31, 2008	153,000	46.85
Granted	3,496	31.30
Exercised	(13,000)	14.74
Outstanding at December 31, 2009	143,496	49.38
Granted	52,504	37.62
Exercised	(3,500)	17.54
Forfeited	(14,000)	58.20
Outstanding at December 31, 2010	178,500	$ 48.77

The total grant date fair value of the 52,504, 3,496 and 28,000 shares vesting in 2010, 2009 and 2008, respectively, was $0.8 million, $0.1 million and $0.7 million, respectively. The intrinsic value of options exercised in 2010 was $0.1 million. Total cash received from options exercised in 2010 was $0.1 million.

	Outstanding and Exercisable Options at December 31, 2010		
Exercise Prices	Number of Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price
$17.54	3,500	0.3 years	$ 17.54
$20.10 - $20.46	17,500	1.9 years	$ 20.32
$28.23 - $41.20	84,000	7.2 years	$ 36.10
$57.63 - $73.26	73,500	6.3 years	$ 64.43

Options for 178,500, 143,496 and 153,000 shares were exercisable with weighted average exercise prices of $45.86, $49.38 and $46.85 at December 31, 2010, 2009 and 2008, respectively. The aggregate intrinsic value of the shares outstanding subject to options at December 31, 2010 was $1.4 million with a weighted average remaining contractual term of 6.2 years.

Note 13. Derivatives

Interest Rate Swaps

From time to time we enter into interest rate swaps to manage our exposure to possible future interest rate increases. Under these transactions we swap the variable interest rate we would otherwise pay on a portion of our bank debt for a fixed interest rate. As of December 31, 2010, we had two outstanding interest rate swaps; both were cash flow hedges. There was no material amount of ineffectiveness. This table provides certain information about those interest rate swaps:

Remaining Term	Amount	Fixed Rate	Floating Rate
January 2011 – May 2012	$ 15,000,000	4.53%	3 month LIBOR
January 2011 – May 2012	$ 15,000,000	4.16%	3 month LIBOR

Commodity Derivatives

We have entered into various types of derivative instruments covering some of our projected natural gas, natural gas liquids and oil production. These transactions are intended to reduce our exposure to market price volatility by setting the price(s) we will receive for that production. Our decisions on the price(s), type and quantity of our production hedged is based, in part, on our view of current and future market conditions. As of December 31, 2010, our derivative instruments consisted of the following types of swaps and collars:

- *Swaps*. We receive or pay a fixed price for the hedged commodity and pay or receive a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.
- *Collars*. A collar contains a fixed floor price (put) and a ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, we receive the fixed price and pay the market price. If the market price is between the call and the put strike price, no payments are due from either party.
- *Basis Swaps*. We receive or pay the NYMEX settlement value plus or minus a fixed delivery point price for the hedged commodity and pay or receive the published index price at the specified delivery point. We use basis swaps to hedge the price risk between NYMEX and its physical delivery points.

Oil and Natural Gas Segment:

At December 31, 2010, the following cash flow hedges were outstanding:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Jan'11 – Dec'11	Crude oil – swap	4,000 Bbl/day	$ 84.28	WTI – NYMEX
Jan'12 – Dec'12	Crude oil – swap	1,500 Bbl/day	$ 82.49	WTI – NYMEX
Jan'11 – Dec'11	Natural gas – swap	45,000 MMBtu/day	$ 4.93	IF – NYMEX (HH)
Jan'11 – Dec'11	Natural gas – basis differential swap	15,000 MMBtu/day	($ 0.14)	Tenn Zone 0 – NYMEX
Jan'12 – Dec'12	Natural gas – swap	15,000 MMBtu/day	$ 5.62	IF – PEPL
Jan'11 – Dec'11	Liquids – swap (1)	644,406 Gal/mo	$ 0.97	OPIS – Conway

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

At December 31, 2010, the following non-qualifying cash flow derivatives were outstanding:

Term	Commodity	Hedged Volume	Basis Differential	Hedged Market
Jan'11 – Dec'11	Natural gas – basis differential swap	15,000 MMBtu/day	($ 0.14)	Tenn Zone 0 – NYMEX
Jan'11 – Dec'11	Natural gas – basis differential swap	10,000 MMBtu/day	($ 0.21)	CEGT – NYMEX
Jan'11 – Dec'11	Natural gas – basis differential swap	10,000 MMBtu/day	($ 0.23)	PEPL – NYMEX

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

	Balance Sheet Location	Derivative Assets Fair Value December 31, 2010	December 31, 2009
		(In thousands)	
Derivatives designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative assets	$ 5,091	$ 9,945
Long-term	Non-current derivative assets	2,537	0
Total derivatives designated as hedging instruments		7,628	9,945
Derivatives not designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative assets	477	0
Total derivatives not designated as hedging instruments		477	0
Total derivative assets		$ 8,105	$ 9,945

	Balance Sheet Location	Derivative Liabilities Fair Value December 31, 2010	December 31, 2009
		(In thousands)	
Derivatives designated as hedging instruments			
Interest rate swaps:			
Current	Current portion of derivative liabilities	$ 1,139	$ 806
Long-term	Long-term derivative liabilities	475	1,142
Commodity derivatives:			
Current	Current portion of derivative liabilities	13,166	1,424
Long-term	Long-term derivative liabilities	3,884	0
Total derivatives designated as hedging instruments		18,664	3,372
Derivatives not designated as hedging instruments			
Commodity derivatives (basis swaps):			
Current	Current portion of derivative liabilities	141	0
Total derivatives not designated as hedging instruments		141	0
Total derivative liabilities		$ 18,805	$ 3,372

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

We recognize in accumulated other comprehensive income (OCI) the effective portion of any changes in fair value and reclassify the recognized gains (losses) on the sales to revenue and on the purchases to expense as each of the underlying transactions are settled. As of December 31, 2010 and 2009, we had a loss of $6.9 million and a gain of $4.5 million, net of tax, respectively, in accumulated OCI.

Based on market prices at December 31, 2010, we expect to transfer to earnings a loss of approximately $5.4 million, net of tax, of the loss included in accumulated OCI over the next 12 months as the various transactions are settled. The interest rate swaps and the commodity derivative instruments existing as of December 31, 2010 are expected to mature by May 2012 and December 2012, respectively.

Certain derivatives do not qualify as cash flow hedges. Currently, we have three basis swaps that do not qualify as cash flow hedges. For these, any changes in their fair value that occurs before their maturity (i.e., temporary fluctuations in value) are reported in the consolidated statements of operations within our oil and natural gas revenues. Any 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 our OCI until the hedged item is recognized into earnings. Any change in fair value resulting from ineffectiveness is recognized in our oil and natural gas revenues.

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

Derivatives in Cash Flow Hedging Relationships	Amount of Gain or (Loss) Recognized in Accumulated OCI on Derivative (Effective Portion) [(1)]	
	2010	2009
	(In thousands)	
Interest rate swaps	$ (996)	$ (1,204)
Commodity derivatives	(5,855)	5,662
Total	$ (6,851)	$ 4,458

(1) Net of taxes.

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

Derivative Instrument	Location of Gain or (Loss) Reclassified from Accumulated OCI into Income & Location of Gain or (Loss) Recognized in Income	Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income [(1)]		Amount of Gain or (Loss) Recognized in Income [(2)]	
		2010	2009	2010	2009
		(In thousands)			
Commodity derivatives	Oil and natural gas revenue	$ 53,473	$ 100,286	$ 700	$ (897)
Interest rate swaps	Interest, net	(1,218)	(1,036)	0	0
	Total	$ 52,255	$ 99,250	$ 700	$ (897)

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

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

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Income on Derivative	Amount of Gain or (Loss) Recognized in Income on Derivative	
		2010	2009
		(In thousands)	
Commodity derivatives (basis swaps)	Oil and natural gas revenue	$ 336	$ (3,469)
Total		$ 336	$ (3,469)

Note 14. Fair Value Measurements

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

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

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

The following tables set forth our recurring fair value measurements:

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

	December 31, 2009			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Financial assets (liabilities):				
Interest rate swaps	$ 0	$ 0	$ (1,948)	$ (1,948)
Commodity derivatives	$ 0	$ (11,427)	$ 19,948	$ 8,521

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

Level 2 Fair Value Measurements

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

Level 3 Fair Value Measurements

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

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

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

	Net Derivatives			
	For the Year Ended December 31, 2010		For the Year Ended December 31, 2009	
	Interest Rate Swaps	Commodity Swaps and Collars	Interest Rate Swaps	Commodity Swaps and Collars
	(In thousands)			
Beginning of period	$ (1,948)	$ 19,948	$ (2,516)	$ 58,508
Total gains or losses (realized and unrealized):				
Included in earnings (loss)[(1)]	(1,218)	64,470	(1,036)	100,018
Included in other comprehensive income (loss)	334	(10,116)	568	(36,616)
Purchases, issuance and settlements	1,218	(63,434)	1,036	(101,962)
End of period	$ (1,614)	$ 10,868	$ (1,948)	$ 19,948
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, 2010 and 2009	$ 0	$ 1,036	$ 0	$ (1,944)

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

Based on our valuation at December 31 2010, we determined that the non-performance risk with regard to our counterparties was immaterial.

Note 15. Commitments and Contingencies

We lease office space or yards in Elk City, Oklahoma City and Tulsa, Oklahoma; Houston, Texas; Denver, Colorado; Pinedale, Wyoming; and Pittsburgh, Pennsylvania under the terms of operating leases expiring through January, 2015. Additionally, we have several equipment leases and lease space on short-term commitments to stack excess drilling rig equipment and production inventory. Future minimum rental payments under the terms of the leases are approximately $1.7 million, $1.4 million, $1.3 million, $1.3 million and $0.2 million in 2011-2015, respectively. Total rent expense incurred was $1.8 million, $2.1 million and $2.1 million in 2010, 2009 and 2008, respectively.

The Unit 1984 Oil and Gas Limited Partnership and the 1986 Energy Income Limited Partnership agreements along with the employee oil and gas limited partnerships require, on the election of a limited partner, that we repurchase the limited partner’s interest at amounts to be determined by appraisal in the future. These repurchases in any one year are limited to 20% of the units outstanding. We made repurchases of $22,000 in 2010, $1,000 in 2009 and $241,000 in 2008.

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 $13.7 million of new drilling rig components, drill pipe, drill collars and related equipment.

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

Note 16. Industry Segment Information

Our three main business segments and the different products and services they offer are:

Segment	Services or Products
Contract drilling	Onshore contract drilling of oil and natural gas wells
Oil and natural gas	Development, acquisition and production of oil and natural gas properties
Midstream	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). Each segment’s performance is evaluated based on its operating income (loss) which is defined as its operating revenues less operating expenses and depreciation, depletion, amortization and impairment.

Although we have some production in Canada, it is not significant and therefore not split out below.

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

	2010	2009	2008
		(In thousands)	
Revenues:			
Contract drilling	$ 356,527	$ 251,364	$ 688,196
Elimination of inter-segment revenue	(40,143)	(15,049)	(65,469)
Contract drilling net of inter-segment revenue	316,384	236,315	622,727
Oil and natural gas	400,807	357,879	553,998
Gas gathering and processing	201,320	142,491	237,999
Elimination of inter-segment revenue	(46,804)	(33,863)	(56,269)
Gas gathering and processing net of inter-segment revenue	154,516	108,628	181,730
Other	10,138	7,076	(362)
Total revenues	$ 881,845	$ 709,898	$ 1,358,093
Operating income (loss) (1):			
Contract drilling	$ 59,601	$ 50,909	$ 239,979
Oil and natural gas	176,649	(125,777)(4)	(3,757)(3)
Gas gathering and processing	16,985	4,616	16,442
Total operating income (loss)	253,235	(70,252)	252,664
General and administrative expense	(26,152)	(24,011)	(25,419)
Interest expense, net	0	(539)	(1,304)
Other income (expense)—net	10,138	7,076	(362)
Income (loss) before income taxes	$ 237,221	$ (87,726)	$ 225,579
Identifiable assets (2):			
Contract drilling	$ 998,658	$ 951,702	$ 1,009,292
Oil and natural gas	1,441,797	1,068,970(4)	1,363,534(3)
Gas gathering and processing	176,596	163,625	169,687
Total identifiable assets	2,617,051	2,184,297	2,542,513
Corporate assets	52,189	44,102	39,353
Total assets	$ 2,669,240	$ 2,228,399	$ 2,581,866
Capital expenditures:			
Contract drilling	$ 118,806	$ 67,686	$ 196,229
Oil and natural gas	463,870	230,550	561,548
Gas gathering and processing	29,815	9,899	49,887
Other	6,417	474	9,860
Total capital expenditures	$ 618,908	$ 308,609	$ 817,524
Depreciation, depletion, amortization and impairment:			
Contract drilling	$ 69,970	$ 45,326	$ 69,841
Oil and natural gas			
Depreciation, depletion and amortization	118,793	114,681	159,550
Impairment of oil and natural gas properties	0	281,241(4)	281,966(3)
Gas gathering and processing	15,385	16,104	14,822
Other	976	1,055	699
Total depreciation, depletion, amortization and impairment	$ 205,124	$ 458,407	$ 526,878

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

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

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

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

Note 17. Selected Quarterly Financial Information

Summarized unaudited quarterly financial information is as follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
	(In thousands except per share amounts)			
2010:				
Revenues	$ 206,550	$ 204,603	$ 218,116	$ 252,576
Gross profit (1)	$ 59,319	$ 53,499	$ 63,371	$ 77,046
Net income	$ 36,153	$ 32,175	$ 34,491	$ 43,665
Net income per common share:				
Basic	$ 0.77	$ 0.68	$ 0.73	$ 0.92
Diluted	$ 0.76	$ 0.68	$ 0.73	$ 0.92
2009:				
Revenues	$ 201,062	$ 164,074	$ 167,430	$ 177,332
Gross profit (loss) (1)	$ (232,004)	$ 55,970	$ 54,111	$ 51,671
Net income (loss)	$ (147,493)	$ 32,031	$ 31,449	$ 28,513
Net income (loss) per common share:				
Basic (2)	$ (3.14)	$ 0.68	$ 0.67	$ 0.61
Diluted (2)	$ (3.14)	$ 0.68	$ 0.66	$ 0.60

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

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

SUPPLEMENTAL OIL AND GAS DISCLOSURES
(UNAUDITED)

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

	2010	2009	2008
		(In thousands)	
Capitalized costs:			
Proved properties	$ 2,738,093	$ 2,309,193	$ 2,090,623
Unproved properties	175,065	140,129	160,034
	2,913,158	2,449,322	2,250,657
Accumulated depreciation, depletion, amortization and impairment	(1,542,352)	(1,424,559)	(1,029,617)
Net capitalized costs	$ 1,370,806	$ 1,024,763	$ 1,221,040
Cost incurred:			
Unproved properties acquired	$ 75,739	$ 37,137	$ 113,104
Proved properties acquired	50,000	3,722	41,227
Exploration	48,304	30,547	41,474
Development	279,903	154,579	351,876
Asset retirement obligation	9,924	4,565	13,867
Total costs incurred	$ 463,870	$ 230,550	$ 561,548

The following table shows a summary of the oil and natural gas property costs not being amortized at December 31, 2010, by the year in which such costs were incurred:

	2010	2009	2008	2007 and Prior	Total
			(In thousands)		
Undeveloped Leasehold Acquired	$ 68,078	$ 24,490	$ 53,790	$ 28,707	$ 175,065

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:

	2010	2009	2008
		(In thousands)	
Revenues	$ 392,229	$ 352,572	$ 545,937
Production costs	(91,143)	(75,214)	(102,207)
Depreciation, depletion, amortization and impairment	(117,793)	(394,942)	(440,588)
	183,293	(117,584)	3,142
Income tax (expense) benefit	(70,110)	43,153	(1,141)
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 113,183	$ (74,431)	$ 2,001

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

	Oil Bbls	Liquids Bbls	Natural Gas Mcf
		(In thousands)	
2010:			
Proved developed and undeveloped reserves:			
Beginning of year	11,669	14,653	419,061
Revision of previous estimates[(1)]	434	(1,559)	(25,007)
Extensions and discoveries	3,473	878	31,328
Infill reserves in existing proved fields	2,152	3,482	34,128
Purchases of minerals in place	1,293	212	1,732
Production	(1,521)	(1,549)	(40,756)
Sales	(6)	0	0
End of Year	17,494	16,117	420,486
Proved developed reserves:			
Beginning of year	9,183	11,538	338,217
End of year	12,773	12,088	346,928
Proved undeveloped reserves:			
Beginning of year	2,486	3,115	80,844
End of year	4,721	4,029	73,558
2009:			
Proved developed and undeveloped reserves:			
Beginning of year	9,699	10,171	450,135
Revision of previous estimates[(1)]	459	2,793	(57,393)
Extensions and discoveries	2,135	1,996	50,480
Infill reserves in existing proved fields[(2)]	618	1,174	19,872
Purchases of minerals in place	44	7	30
Production	(1,286)	(1,488)	(44,063)
End of Year	11,669	14,653	419,061
Proved developed reserves:			
Beginning of year	7,508	8,638	355,824
End of year	9,183	11,538	338,217
Proved undeveloped reserves:			
Beginning of year	2,191	1,533	94,311
End of year	2,486	3,115	80,844
2008:			
Proved developed and undeveloped reserves:			
Beginning of year	9,676	6,149	419,616
Revision of previous estimates[(3)]	(1,278)	2,023	(23,431)
Extensions and discoveries	1,511	1,522	60,369
Infill reserves in existing proved fields[(2)]	830	1,657	29,848
Purchases of minerals in place	221	208	11,206
Production	(1,261)	(1,388)	(47,473)
End of Year	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
Proved undeveloped reserves:			
Beginning of year	1,906	1,016	93,545
End of year	2,191	1,533	94,311

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

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

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

Estimates of oil, NGLs and natural gas reserves require extensive judgments of reservoir engineering data. Assigning monetary values to such estimates does not reduce the subjectivity and changing nature of such reserve estimates. Indeed the uncertainties

inherent in the disclosure are compounded by applying additional estimates of the rates and timing of production and the costs that will be incurred in developing and producing the reserves. The information set forth in this report is, therefore, subjective and, since judgments are involved, may not be comparable to estimates submitted by other oil and natural gas producers. In addition, since prices and costs do not remain static and no price or cost escalations or de-escalations have been considered, the results are not necessarily indicative of the estimated fair market value of estimated proved reserves, nor of estimated future cash flows.

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

	2010	2009	2008
		(In thousands)	
Future cash flows	$ 3,745,046	$ 2,403,892	$ 2,694,217
Future production costs	(1,054,630)	(777,725)	(769,325)
Future development costs	(303,152)	(195,486)	(253,941)
Future income tax expenses	(799,260)	(433,366)	(510,361)
Future net cash flows	1,588,004	997,315	1,160,590
10% annual discount for estimated timing of cash flows	(732,918)	(450,980)	(536,116)
Standardized measure of discounted future net cash flows relating to proved oil, NGLs and natural gas reserves	$ 855,086	$ 546,335	$ 624,474

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

	2010	2009	2008
		(In thousands)	
Sales and transfers of oil and natural gas produced, net of production costs	$ (301,086)	$ (277,358)	$ (443,729)
Net changes in prices and production costs	379,097	(145,839)	(548,683)
Revisions in quantity estimates and changes in production timing	(67,116)	(54,327)	(34,066)
Extensions, discoveries and improved recovery, less related costs	340,771	136,695	229,928
Changes in estimated future development costs	15,974	100,304	20,273
Previously estimated cost incurred during the period	45,327	16,301	55,763
Purchases of minerals in place	42,280	1,288	20,797
Sales of minerals in place	(120)	0	0
Accretion of discount	77,536	89,256	148,160
Net change in income taxes	(200,815)	39,062	223,188
Other—net	(23,097)	16,479	(37,488)
Net change	308,751	(78,139)	(365,857)
Beginning of year	546,335	624,474	990,331
End of year	$ 855,086	$ 546,335	$ 624,474

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.

The December 31, 2010, future cash flows were computed by applying the unescalated 12-month average prices of $79.43 per barrel for oil, $49.35 per barrel for NGLs and $4.38 per Mcf for natural gas, adjusted for price differentials, relating to proved reserves and to the year-end quantities of those reserves. Prior to 2009, the price was based on the single-day period-end price. Future price changes are considered only to the extent provided by contractual arrangements in existence at year-end.

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

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

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

Exhibit 99.2

Item 1. Financial Statements

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	March 31, 2011	December 31, 2010
	(In thousands except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,236	$ 1,359
Accounts receivable, net of allowance for doubtful accounts of $5,083 both at March 31, 2011 and at December 31, 2010	134,858	130,142
Materials and supplies	6,290	6,316
Current derivative assets (Note 10)	0	5,568
Current income tax receivable	19,316	25,211
Current deferred tax asset	19,757	13,537
Prepaid expenses and other	7,558	6,047
Total current assets	189,015	188,180
Property and equipment:		
Drilling equipment	1,313,374	1,273,861
Oil and natural gas properties on the full cost method:		
Proved properties	2,858,466	2,738,093
Undeveloped leasehold not being amortized	181,503	175,065
Gas gathering and processing equipment	208,610	199,564
Transportation equipment	33,266	31,688
Other	30,268	28,511
	4,625,487	4,446,782
Less accumulated depreciation, depletion, amortization and impairment	2,106,979	2,047,031
Net property and equipment	2,518,508	2,399,751
Goodwill	62,808	62,808
Other intangible assets, net	2,741	3,022
Non-current derivative assets (Note 10)	0	2,537
Other assets	12,972	12,942
Total assets	$ 2,786,044	$ 2,669,240

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

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED) - CONTINUED

	March 31, 2011	December 31, 2010
	(In thousands except share amounts)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 108,495	$ 89,885
Accrued liabilities (Note 5)	27,099	30,093
Contract advances	5,247	2,582
Current portion of derivative liabilities (Note 10)	25,558	14,446
Current portion of other long-term liabilities (Note 6)	9,875	10,122
Total current liabilities	176,274	147,128
Long-term debt (Note 6)	185,000	163,000
Long-term derivative liabilities (Note 10)	9,904	4,359
Other long-term liabilities (Note 6)	90,917	88,030
Deferred income taxes	579,085	556,106
Shareholders' equity:		
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	0	0
Common stock, $.20 par value, 175,000,000 shares authorized, 48,169,566 and 47,910,431 shares issued, respectively	9,524	9,493
Capital in excess of par value	400,543	393,501
Accumulated other comprehensive loss	(20,704)	(6,851)
Retained earnings	1,355,501	1,314,474
Total shareholders' equity	1,744,864	1,710,617
Total liabilities and shareholders' equity	$ 2,786,044	$ 2,669,240

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

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

	Three Months Ended March 31,	
	2011	2010
	(In thousands)	
Revenues:		
Contract drilling	$ 97,988	$ 60,854
Oil and natural gas	109,834	99,053
Gas gathering and processing	39,764	41,135
Other	(181)	5,508
Total revenues	247,405	206,550
Expenses:		
Contract drilling:		
Operating costs	52,844	40,900
Depreciation	17,297	13,786
Oil and natural gas:		
Operating costs	30,781	25,034
Depreciation, depletion and amortization	40,268	25,336
Gas gathering and processing:		
Operating costs	29,055	32,726
Depreciation and amortization	3,773	3,941
General and administrative	6,892	6,279
Interest, net	54	0
Total operating expenses	180,964	148,002
Income before income taxes	66,441	58,548
Income tax expense:		
Current	0	2,240
Deferred	25,414	20,155
Total income taxes	25,414	22,395
Net income	$ 41,027	$ 36,153
Net income per common share:		
Basic	$ 0.86	$ 0.77
Diluted	$ 0.86	$ 0.76

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

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
	(In thousands)	
OPERATING ACTIVITIES:		
Net income	$ 41,027	$ 36,153
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	61,577	43,313
Unrealized (gain) loss on derivatives	2,328	(1,148)
Deferred tax expense	25,414	20,155
(Gain) loss on disposition of assets	170	(5,435)
Stock compensation plans	3,286	3,316
Other	895	676
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	(4,716)	(13,304)
Accounts payable	(15,952)	966
Material and supplies inventory	26	245
Accrued liabilities	101	(4,269)
Contract advances	2,665	(1,537)
Other - net	4,384	536
Net cash provided by operating activities	121,205	79,667
INVESTING ACTIVITIES:		
Capital expenditures	(165,617)	(105,269)
Producing property and other acquisitions	(4,052)	(294)
Proceeds from disposition of assets	457	18,313
Other - net	0	324
Net cash used in investing activities	(169,212)	(86,926)
FINANCING ACTIVITIES:		
Borrowings under line of credit	88,800	19,100
Payments under line of credit	(66,800)	(19,100)
Proceeds from exercise of stock options	513	246
Book overdrafts	25,371	6,912
Net cash provided by financing activities	47,884	7,158
Net decrease in cash and cash equivalents	(123)	(101)
Cash and cash equivalents, beginning of period	1,359	1,140
Cash and cash equivalents, end of period	$ 1,236	$ 1,039

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

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	Three Months Ended March 31,	
	2011	2010
	(In thousands)	
Net income	$ 41,027	$ 36,153
Other comprehensive income, net of taxes:		
Change in value of derivative instruments used as cash flow hedges, net of tax of ($9,184) and $14,667	(14,827)	23,672
Reclassification - derivative settlements, Net of tax of ($127) and ($2,014)	(205)	(3,252)
Ineffective portion of derivatives, net of tax of $730 and ($417)	1,179	(674)
Comprehensive income	$ 27,174	$ 55,899

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

NOTE 1 – BASIS OF PREPARATION AND PRESENTATION

The accompanying unaudited condensed consolidated financial statements in this quarterly report include the accounts of Unit Corporation and all its subsidiaries and affiliates and have been prepared under the rules and regulations of the SEC. The terms "company," "Unit," "we," "our" and "us" refer to Unit Corporation, a Delaware corporation, and, as appropriate, one or more of its subsidiaries and affiliates, except as otherwise indicated or as the context otherwise requires.

The accompanying condensed consolidated financial statements are unaudited and do not include all the notes in our annual financial statements. This quarterly report should be read in conjunction with the audited consolidated financial statements and notes included in our Form 10-K, filed February 24, 2011, for the year ended December 31, 2010.

In the opinion of management, the accompanying unaudited condensed consolidated financial statements contain all normal recurring adjustments (including the elimination of all intercompany transactions) necessary to fairly state the following:

- Balance Sheets at March 31, 2011 and December 31, 2010;
- Statements of Income for the three months ended March 31, 2011 and 2010;
- Cash Flows for the three months ended March 31, 2011 and 2010; and
- Statements of Comprehensive Income for the three months ended March 31, 2011 and 2010.

Our financial statements are prepared in conformity with generally accepted accounting principles in the United States (GAAP). GAAP requires us to make certain estimates and assumptions that may affect the amounts reported in our condensed consolidated financial statements and accompanying notes. Actual results may differ from those estimates. Results for the three months ended March 31, 2011 and 2010 are not necessarily indicative of the results to be realized for the full year in the case of 2011, or that we realized for the full year of 2010.

With respect to the unaudited financial information for the three month periods ended March 31, 2011 and 2010, included in this quarterly report, PricewaterhouseCoopers LLP reported that it applied limited procedures in accordance with professional standards in reviewing that information. Its separate report, dated May 3, 2011, which is included in this quarterly report, states that it did not audit and it does not express an opinion on that unaudited financial information. Accordingly, the degree of reliance placed on its report should be restricted in light of the limited review procedures applied. PricewaterhouseCoopers LLP is not subject to the liability provisions of Section 11 of the Securities Act of 1933 (Act) for its report on the unaudited financial information because that report is not a "report" or a "part" of a registration statement prepared or certified by PricewaterhouseCoopers LLP within the meaning of Sections 7 and 11 of the Act.

NOTE 2 – OIL AND NATURAL GAS PROPERTIES

Full cost accounting rules require us to review the carrying value of our oil and natural gas properties at the end of each quarter. Under those rules, the maximum amount allowed as the carrying value of those properties is referred to as the ceiling. The ceiling is the sum of the present value (using a 10% discount rate) of the estimated future net revenues from our proved reserves based on the unescalated 12-month average price on our oil, natural gas liquids (NGLs) and natural gas adjusted for any cash flow hedges, plus the cost of properties not being amortized, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, less related income taxes. In the event the unamortized cost of the amortized oil and natural gas properties exceeds the full cost ceiling, the excess amount is charged to expense in the period during which the 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.

At March 31, 2011, using the existing 12-month average commodity prices, including the discounted value of our commodity hedges, we were not required to record a ceiling test write-down. However, if there are declines in the 12-month average prices, including the discounted value of our commodity hedges, we may be required to record a write-down in future periods. Our qualifying cash flow hedges used in the ceiling test determination as of March 31, 2011, consisted of swaps covering 29.4 Bcfe in 2011, 17.6 Bcfe in 2012 and 2.2 Bcfe in 2013. The effect of those hedges on the March 31, 2011 ceiling test was a $40.9 million pre-tax increase in the discounted net cash flows of our oil and natural gas properties. Even without the impact of those hedges, we would not have been required to take a write-down for the quarter. Our oil and natural gas hedging is discussed in Note 10 of the Notes to our Condensed Consolidated Financial Statements.

NOTE 3 – ACQUISITIONS

On June 2, 2010, we completed an acquisition of oil and natural gas properties from certain unaffiliated parties in an effort to explore and develop more oil rich plays. The properties were purchased for approximately $73.7 million in cash, after post close adjustments. The purchase price allocation was $48.7 million for proved properties and $25.0 million for undeveloped leasehold not being amortized. The acquisition included approximately 45,000 net leasehold acres and 10 producing oil wells. These properties focused on the Marmaton horizontal oil play located mainly in Beaver County, Oklahoma. At the time of acquisition, proved developed producing net reserves associated with the 10 acquired producing wells was approximately 762,000 BOE – consisting of 511,000 barrels of oil, 155,000 barrels of NGLs and 573 MMcf of natural gas.

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

NOTE 4 – EARNINGS PER SHARE

Information related to the calculation of earnings per share follows:

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the three months ended			
March 31, 2011:			
Basic earnings per common share	$ 41,027	47,584	$ 0.86
Effect of dilutive stock options, restricted stock and stock appreciation rights (SARs)	0	321	0
Diluted earnings per common share	$ 41,027	47,905	$ 0.86
For the three months ended			
March 31, 2010:			
Basic earnings per common share	$ 36,153	47,121	$ 0.77
Effect of dilutive stock options, restricted stock and SARs	0	565	(0.01)
Diluted earnings per common share	$ 36,153	47,686	$ 0.76

The following table shows the number of stock options and SARs (and their average exercise price) excluded because their option exercise prices were greater than the average market price of our common stock:

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
Stock options and SARs	73,500	132,165
Average Exercise Price	$ 64.43	$ 59.87

NOTE 5 – ACCRUED LIABILITIES

Accrued liabilities consisted of the following:

	March 31, 2011	December 31, 2010
	(In thousands)	
Employee costs	$ 9,520	$ 16,499
Lease operating expense accrual	6,064	6,214
Taxes	3,486	1,310
Hedge settlements	2,475	1,634
Other	5,554	4,436
Total accrued liabilities	$ 27,099	$ 30,093

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

Long-Term Debt

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

	March 31, 2011	December 31, 2010
	(In thousands)	
Revolving credit facility with average interest rates, including the effect of hedging, of 2.8% at March 31, 2011 and 3.5% at December 31, 2010	$ 185,000	$ 163,000
Less current portion	0	0
Total long-term debt	$ 185,000	$ 163,000

Our credit facility has a maximum credit amount of $400.0 million and matures on May 24, 2012. The lenders' current commitment under the credit facility is $325.0 million. Our borrowings are limited to the commitment amount that we from time to time elect. As of March 31, 2011, the commitment amount was $325.0 million. We are charged a commitment fee ranging from 0.375 to 0.50 of 1% on the amount available but not borrowed. The rate varies based on the amount borrowed as a percentage of the amount of the total borrowing base. To date we have paid $1.2 million in origination, agency and syndication fees under the credit facility. We are amortizing these fees over the life of the agreement.

The lenders' aggregate commitment is limited to the lesser of the amount 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 segment. The April 1, 2011 redetermination increased the borrowing base to $600.0 million. We or the lenders may request a onetime special redetermination of the amount of the borrowing base between each scheduled redetermination. In addition, we may request a redetermination following the completion of an acquisition that meets the requirements set forth in the credit 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 period. During any LIBOR funding period, the outstanding principal balance of the promissory note to which the LIBOR option applies may be repaid after three days prior notice to the administrative agent and on payment of any applicable funding indemnification amounts. LIBOR interest is computed as the sum of the LIBOR base for the applicable period plus 1.75% to 2.50% depending on the level of debt as a percentage of the borrowing base and is payable at the end of each period, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the BOK Financial Corporation (BOKF) National Prime Rate, which cannot be less than LIBOR plus 1.00%, and is payable at the end of each month and the principal borrowed may be paid at any time, in part or in whole, without a premium or penalty. At March 31, 2011, all of our $185.0 million in outstanding borrowings 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 March 31 2011, we were in compliance with our credit facility's covenants.

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 March 31, 2011 approximates its fair value.

At March 31, 2011, the carrying values on the consolidated balance sheets for cash and cash equivalents, accounts receivable, accounts payable, other current assets and current liabilities approximate their fair value because of their short term nature.

Securities being registered under the registration statement are debt securities guaranteed by our wholly-owned domestic direct and indirect subsidiaries. Unit Corporation (Unit), as the parent company, has no independent assets or operations. The guarantees registered under the registration statement are full and unconditional and joint and several, and subsidiaries of Unit other than the subsidiary guarantors are minor. There are no significant restrictions on the ability of our parent company to receive funds from our subsidiaries through dividends, loans, advances or otherwise.

Other Long-Term Liabilities

Other long-term liabilities consisted of the following:

	March 31, 2011	December 31, 2010
	(In thousands)	
Asset retirement obligations (ARO) liability	$ 71,338	$ 69,265
Workers' compensation	17,666	17,566
Separation benefit plans	5,953	5,690
Gas balancing liability	3,263	3,263
Deferred compensation plan	2,572	2,368
	100,792	98,152
Less current portion	9,875	10,122
Total other long-term liabilities	$ 90,917	$ 88,030

The estimated annual payments due under the terms of our debt and other long-term liabilities during each of the five successive twelve month periods beginning April 1, 2011 (and through 2016) are $9.9 million, $199.6 million, $3.3 million, $2.7 million and $2.1 million, respectively.

NOTE 7 – ASSET RETIREMENT OBLIGATIONS

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

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

	Three Months Ended March 31,	
	2011	2010
	(In thousands)	
ARO liability, January 1:	$ 69,265	$ 56,404
Accretion of discount	874	687
Liability incurred	1,559	472
Liability settled	(359)	(270)
Revision of estimates	(1)	49
ARO liability, March 31:	71,338	57,342
Less current portion	1,836	1,632
Total long-term plugging liability	$ 69,502	$ 55,710

NOTE 8 – NEW ACCOUNTING PRONOUNCEMENTS

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

NOTE 9 – STOCK-BASED COMPENSATION

For the three months ended March 31, 2011 and 2010, we recognized stock compensation expense for restricted stock awards, stock options and stock settled SARs of $2.3 million and $2.5 million, respectively, and capitalized stock compensation cost for oil and natural gas properties of $0.6 million and $0.5 million, respectively. For these same periods, the tax benefit related to this stock based compensation was $0.9 million each period. The remaining unrecognized compensation cost related to unvested awards at March 31, 2011 is approximately $16.3 million of which $3.1 million is anticipated to be capitalized. The weighted average period of time over which this cost will be recognized is 0.9 years.

We did not grant any stock options or SARs during either of the three month periods ending March 31, 2011 and 2010.

The following table shows the fair value of any restricted stock awards granted during the periods indicated:

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
Shares granted	192,581	248,383
Estimated fair value (in millions)	$ 10.0	$ 10.6
Percentage of shares granted expected to be distributed	93%	93%

The restricted stock awards granted during the first three months of 2011 will be recognized over a three year vesting period except for certain designated executive officers. For grants to those executive offers covering 66,869 shares of the total granted, 70% will vest in equal one-third annual increments, the other 30% of the shares awarded will cliff vest in the first quarter of 2014, but only if certain performance criteria are met which could result in fewer or additional shares vesting. These awards increased the stock compensation expense and the capitalized cost related to oil and natural gas properties for the first quarter of 2011 by an aggregate of $0.5 million.

NOTE 10 – DERIVATIVES

Interest Rate Swaps

From time to time we enter into interest rate swaps to manage our exposure to possible future interest rate increases under our credit facility. Under these transactions we swap the variable interest rate we would otherwise pay on a portion of our bank debt for a fixed interest rate. As of March 31, 2011, we had two outstanding interest rate swaps; both were cash flow hedges. There was no material amount of ineffectiveness. This table provides certain information about those interest rate swaps:

Remaining Term	Amount	Fixed Rate	Floating Rate
April 2011 – May 2012	$ 15,000,000	4.53%	3 month LIBOR
April 2011 – May 2012	$ 15,000,000	4.16%	3 month LIBOR

Commodity Derivatives

We have entered into various types of derivative transactions covering some of our projected natural gas, NGLs and oil production. These transactions are intended to reduce our exposure to market price volatility by setting the price(s) we will receive for that production. Our decisions on the price(s), type and quantity of our production hedged is based, in part, on our view of current and future market conditions. As of March 31, 2011, our derivative transactions consisted of the following types of swaps:

- *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.

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

Oil and Natural Gas Segment:

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

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps		Hedged Market
Apr'11 – Dec'11	Crude oil – swap	4,000 Bbl/day	$	84.28	WTI – NYMEX
Jan'12 – Dec'12	Crude oil – swap	3,000 Bbl/day	$	90.92	WTI – NYMEX
Jan'13 – Dec'13	Crude oil – swap	1,000 Bbl/day	$	101.08	WTI – NYMEX
Apr'11 – Dec'11	Natural gas – swap	10,000 MMBtu/day	$	4.43	CEGT
Apr'11 – Dec'11	Natural gas – swap	70,000 MMBtu/day	$	4.87	IF – NYMEX (HH)
Apr'11 – Dec'11	Natural gas – basis differential swap	15,000 MMBtu/day	($	0.14)	Tenn Zone 0 – NYMEX
Jan'12 – Dec'12	Natural gas – swap	15,000 MMBtu/day	$	5.06	IF – NYMEX (HH)
Jan'12 – Dec'12	Natural gas – swap	15,000 MMBtu/day	$	5.62	IF – PEPL
Apr'11 – Dec'11	Liquids – swap (1)	644,406 Gal/mo	$	0.96	OPIS – Conway

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

At March 31, 2011, the following non-qualifying cash flow derivatives were outstanding:

Term	Commodity	Hedged Volume	Basis Differential		Hedged Market
Apr'11 – Dec'11	Natural gas – basis differential swap	15,000 MMBtu/day	($	0.14)	Tenn Zone 0 –NYMEX
Apr'11 – Dec'11	Natural gas – basis differential swap	10,000 MMBtu/day	($	0.21)	CEGT –NYMEX
Apr'11 – Dec'11	Natural gas – basis differential swap	10,000 MMBtu/day	($	0.23)	PEPL – NYMEX

After March 31, 2011, we entered into the following cash flow hedges:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price		Hedged Market
Jan'12 – Dec'12	Crude oil – swap	1,000 Bbl/day	$	107.31	WTI – NYMEX
Jan'13 – Dec'13	Crude oil – swap	500 Bbl/day	$	104.40	WTI – NYMEX

The following tables present the fair values and locations of the derivative transactions recorded in our balance sheets:

	Balance Sheet Location	Derivative Assets Fair Value March 31, 2011	Derivative Assets Fair Value December 31, 2010
		(In thousands)	
Derivatives designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative assets	$ 0	$ 5,091
Long-term	Non-current derivative assets	0	2,537
Total derivatives designated as hedging instruments		0	7,628
Derivatives not designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative assets	0	477

Total derivatives not designated as hedging instruments	0	477
Total derivative assets	$ 0	$ 8,105

	Balance Sheet Location	Derivative Liabilities Fair Value March 31, 2011	December 31, 2010
		(In thousands)	
Derivatives designated as hedging instruments			
Interest rate swaps:			
Current	Current portion of derivative liabilities	$ 1,167	$ 1,139
Long-term	Long-term derivative liabilities	194	475
Commodity derivatives:			
Current	Current portion of derivative liabilities	24,308	13,166
Long-term	Long-term derivative liabilities	9,710	3,884
Total derivatives designated as hedging instruments		35,379	18,664
Derivatives not designated as hedging instruments			
Commodity derivatives (basis swaps):			
Current	Current portion of derivative liabilities	83	141
Total derivatives not designated as hedging instruments		83	141
Total derivative liabilities		$ 35,462	$ 18,805

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

We recognize in accumulated other comprehensive income (OCI) the effective portion of any changes in fair value and reclassify the recognized gains (losses) on the sales to revenue and the purchases to expense as the underlying transactions are settled. As of March 31, 2011 and 2010, we had a loss of $20.7 million and a gain of $24.2 million, net of tax, respectively, in accumulated OCI.

Based on market prices at March 31, 2011, we expect to transfer a loss of approximately $15.9 million, net of tax, included in accumulated OCI during the next 12 months in the related month of settlement. The interest rate swaps and the commodity derivative instruments existing as of March 31, 2011 are expected to mature by May 2012 and December 2013, respectively.

Certain derivatives do not qualify as cash flow hedges. Currently, we have three basis swaps that do not qualify as cash flow hedges. For these types of derivatives, any changes in the fair value that occurs before their maturity (i.e., temporary fluctuations in value) are reported in the condensed consolidated statements of operations within our oil and natural gas revenues. Changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in OCI until the hedged item is recognized into earnings. Any change in fair value resulting from ineffectiveness is recognized in our oil and natural gas revenues.

Effect of Derivative Instruments on the Condensed Consolidated Statement of Income (cash flow hedges) for the three months ended March 31:

Derivatives in Cash Flow Hedging Relationships	Amount of Gain or (Loss) Recognized in Accumulated OCI on Derivative (Effective Portion) (1) 2011	2010
	(In thousands)	
Interest rate swaps	$ (840)	$ (1,247)
Commodity derivatives	(19,864)	25,451
Total	$ (20,704)	$ 24,204

(1) Net of taxes.

Effect of Derivative Instruments on the Condensed Consolidated Statement of Income (cash flow hedges) for the three months ended March 31:

Derivative Instrument	Location of Gain or (Loss) Reclassified from Accumulated OCI into Income & Location of Gain or (Loss) Recognized in Income	Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income [(1)]		Amount of Gain or (Loss) Recognized in Income [(2)]	
		2011	2010	2011	2010
		(In thousands)			
Commodity derivatives	Oil and natural gas revenue	$ 635	$ 5,573	$ (1,909)	$ 1,091
Interest rate swaps	Interest, net	(303)	(307)	0	0
	Total	$ 332	$ 5,266	$ (1,909)	$ 1,091

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

Effect of Derivative Instruments on the Condensed Consolidated Statement of Income (derivatives not designated as hedging instruments) for the three months ended March 31:

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Income on Derivative	Amount of Gain or (Loss) Recognized in Income on Derivative	
		2011	2010
		(In thousands)	
Commodity derivatives (basis swaps)	Oil and natural gas revenue	$ (601)	$ 57
Total		$ (601)	$ 57

NOTE 11 – FAIR VALUE MEASUREMENTS

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

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

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

The following tables set forth our recurring fair value measurements:

	March 31, 2011		
	Level 2	Level 3	Total
		(In thousands)	
Financial assets (liabilities):			
Interest rate swaps	$ 0	$ (1,361)	$ (1,361)
Commodity derivatives	$ (43,469)	$ 9,368	$ (34,101)

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

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

Level 2 Fair Value Measurements

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

Level 3 Fair Value Measurements

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

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

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

	Net Derivatives			
	For the Three Months Ended March 31, 2011		For the Three Months Ended March 31, 2010	
	Interest Rate Swaps	Commodity Swaps	Interest Rate Swaps	Commodity Swaps and Collars
	(In thousands)			
Beginning of period	$ (1,614)	$ 10,868	$ (1,948)	$ 19,948
Total gains or losses (realized and unrealized):				
Included in earnings[1]	(303)	4,305	(307)	9,074
Included in other comprehensive income (loss)	253	(1,765)	(71)	30,343
Settlements	303	(4,040)	307	(7,926)
End of period	$ (1,361)	$ 9,368	$ (2,019)	$ 51,439
Total gains for the period included in earnings attributable to the change in unrealized gain relating to assets still held at end of period	$ 0	$ 265	$ 0	$ 1,148

(1) Interest rate swaps and commodity swaps and collars are reported in the condensed consolidated statements of income in interest, net and revenues, respectively.

Based on our valuation at March 31, 2011, we determined that the non-performance risk with regard to our counterparties was immaterial.

NOTE 12 – INDUSTRY SEGMENT INFORMATION

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

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

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

We evaluate each segment's performance based on its operating income, which is defined as operating revenues less operating expenses and depreciation, depletion, amortization and impairment. Our natural gas production in Canada is not significant.

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

	Three Months Ended March 31,	
	2011	2010
	(In thousands)	
Revenues:		
Contract drilling	$ 112,508	$ 67,501
Elimination of inter-segment revenue	(14,520)	(6,647)
Contract drilling net of inter-segment revenue	97,988	60,854
Oil and natural gas	109,834	99,053
Gas gathering and processing	57,008	53,734
Elimination of inter-segment revenue	(17,244)	(12,599)
Gas gathering and processing net of inter-segment revenue	39,764	41,135
Other	(181)	5,508
Total revenues	$ 247,405	$ 206,550
Operating income[(1)]:		
Contract drilling	$ 27,847	$ 6,168
Oil and natural gas	38,785	48,683
Gas gathering and processing	6,936	4,468
Total operating income	73,568	59,319
General and administrative expense	(6,892)	(6,279)
Interest expense, net	(54)	0
Other	(181)	5,508
Income before income taxes	$ 66,441	$ 58,548

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
Unit Corporation

We have reviewed the accompanying condensed consolidated balance sheet of Unit Corporation and its subsidiaries as of March 31, 2011, and the related condensed consolidated statements of income and comprehensive income for the three-month periods ended March 31, 2011 and 2010 and the condensed consolidated statements of cash flows for the three-month periods ended March 31, 2011 and 2010. These interim financial statements are the responsibility of the Company's management.

We conducted our review in accordance with standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying condensed consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2010, and the related consolidated statements of operations, shareholders' equity and of cash flows for the year then ended (not presented herein), and in our report dated February 24, 2011, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet information as of December 31, 2010, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

/s/ PricewaterhouseCoopers LLP

Tulsa, Oklahoma
May 3, 2011