CTS CORP
Form 10-Q
July 27, 2017
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

(Mark One)
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended June 30, 2017

OR

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Transition Period from _______________ to _______________

Commission File Number: 1-4639

CTS CORPORATION
(Exact name of registrant as specified in its charter)

Indiana	35-0225010
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification Number)
2375 Cabot Drive, Lisle, IL	60532
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: 630-577-8800

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer o Accelerated filer Non-accelerated filer o Smaller reporting company o

(Do not check if smaller reporting company)

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of July 24, 2017: 32,933,326.

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PART I - FINANCIAL INFORMATION
Item 1. Financial Statements
CTS CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF EARNINGS - UNAUDITED
(In thousands of dollars, except per share amounts)

	Three Months Ended		Six Months Ended	
	June 30, 2017	June 30, 2016	June 30, 2017	June 30, 2016
Net sales	$105,686	$98,693	$205,840	$195,398
Cost of goods sold	69,892	64,236	135,822	127,472
Gross Margin	35,794	34,457	70,018	67,926
Selling, general and administrative expenses	15,809	15,764	31,055	30,411
Research and development expenses	6,049	5,967	12,052	12,130
Restructuring charges	729	206	1,507	206
(Gain) loss on sale of assets	(1)	(11,577)	1	(11,351)
Operating earnings	13,208	24,097	25,403	36,530
Other income (expense):				
Interest expense	(752)	(1,009)	(1,436)	(1,829)
Interest income	298	331	551	879
Other income (expense)	1,170	(1,240)	1,631	(1,436)
Total other income (expense)	716	(1,918)	746	(2,386)
Earnings before income taxes	13,924	22,179	26,149	34,144
Income tax expense	3,958	7,692	7,699	11,794
Net earnings	$9,966	$14,487	$18,450	$22,350
Earnings per share:				
Basic	0.30	0.44	0.56	0.68
Diluted	0.30	0.44	0.55	0.67
Basic weighted – average common shares outstanding:	32,890	32,759	32,846	32,695
Effect of dilutive securities	461	466	493	485
Diluted weighted – average common shares outstanding	33,351	33,225	33,339	33,180
Cash dividends declared per share	0.04	0.04	0.08	0.08

See notes to unaudited condensed consolidated financial statements.

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CTS CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME — UNAUDITED
(In thousands of dollars)

	Three Months Ended		Six Months Ended	
	June 30, 2017	June 30, 2016	June 30, 2017	June 30, 2016
Net earnings	$9,966	$14,487	$18,450	$22,350
Other comprehensive income (loss):				
Changes in fair market value of derivatives, net of tax	(152)	(67)	608	227
Changes in unrealized pension cost, net of tax	942	947	1,758	1,855
Cumulative translation adjustment, net of tax	200	(317)	288	(726)
Other comprehensive income	$990	$563	$2,654	$1,356
Comprehensive earnings	$10,956	$15,050	$21,104	$23,706

See notes to unaudited condensed consolidated financial statements.

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CTS CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(In thousands of dollars)

	(Unaudited) June 30, 2017	December 31, 2016
ASSETS		
Current Assets		
Cash and cash equivalents	$ 107,814	$ 113,805
Accounts receivable, net	66,737	62,612
Inventories, net	36,094	28,652
Other current assets	11,925	10,638
Total current assets	222,570	215,707
Property, plant and equipment, net	85,174	82,111
Other Assets		
Prepaid pension asset	50,107	46,183
Goodwill	69,582	61,744
Other intangible assets, net	69,059	64,370
Deferred income taxes	40,373	45,839
Other	1,525	1,743
Total other assets	230,646	219,879
Total Assets	$ 538,390	$ 517,697
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term notes payable	$ 1,059	$ 1,006
Accounts payable	42,660	40,046
Accrued payroll and benefits	8,631	11,369
Accrued liabilities	42,213	45,708
Total current liabilities	94,563	98,129
Long-term debt	92,800	89,100
Post-retirement obligations	6,913	7,006
Other long-term obligations	7,634	5,580
Total Liabilities	201,910	199,815
Commitments and Contingencies (Note 9)		
Shareholders' Equity		
Common stock	304,715	302,832
Additional contributed capital	38,764	40,521
Retained earnings	426,797	410,979
Accumulated other comprehensive loss	(90,540)	(93,194)
Total shareholders' equity before treasury stock	679,736	661,138
Treasury stock	(343,256)	(343,256)
Total shareholders' equity	336,480	317,882
Total Liabilities and Shareholders' Equity	$ 538,390	$ 517,697

See notes to unaudited condensed consolidated financial statements.

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CTS CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS UNAUDITED
(In thousands of dollars)

	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net earnings	$18,450	$22,350
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation and amortization	9,673	8,925
Pension and other post-retirement plan income	(893)	(794)
Stock-based compensation	1,687	967
Deferred income taxes	4,497	2,877
Loss (gain) on sales of fixed assets	1	(11,351)
Loss on foreign currency hedges, net of cash	73	43
Changes in assets and liabilities:		
Accounts receivable	(1,950)	(5,805)
Inventories	(4,737)	842
Other assets	(76)	(2,115)
Accounts payable	1,616	169
Accrued payroll and benefits	(4,735)	3,553
Accrued expenses	(1,944)	(2,594)
Income taxes payable	(347)	800
Other liabilities	2,115	(1,466)
Pension and other post-retirement plans	(159)	(175)
Net cash provided by operating activities	23,271	16,226
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(9,110)	(7,483)
Proceeds from sale of assets	1	12,237
Payments for acquisitions, net of cash acquired	(19,265)	(73,063)
Net cash used in investing activities	(28,374)	(68,309)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Payments of long-term debt	(790,600)	(1,462,100)
Proceeds from borrowings of long-term debt	794,300	1,482,200
Dividends paid	(2,624)	(2,612)
Taxes paid on behalf of equity award participants	(1,569)	(1,775)
Net cash (used in) provided by financing activities	(493)	15,713
Effect of exchange rate changes on cash and cash equivalents	(395)	(646)
Net decrease in cash and cash equivalents	(5,991)	(37,016)
Cash and cash equivalents at beginning of period	113,805	156,928
Cash and cash equivalents at end of period	$107,814	$119,912
Supplemental cash flow information:		
Cash paid for interest	$1,053	$1,547
Cash paid for income taxes, net	$3,515	$8,703

See notes to unaudited condensed consolidated financial statements.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED
(in thousands except for share and per share data)
June 30, 2017
NOTE 1—Basis of Presentation

The accompanying condensed consolidated financial statements have been prepared by CTS Corporation ("CTS" "we", "our", "us" or the "Company"), without audit, pursuant to the rules and regulations of the Securities and Exchange Commission. Certain information and footnote disclosures normally included in financial statements prepared in accordance with generally accepted accounting principles have been omitted pursuant to such rules and regulations. The unaudited condensed consolidated financial statements should be read in conjunction with the financial statements, notes thereto, and other information included in the Company's Annual Report on Form 10 K for the year ended December 31, 2016.

The accompanying unaudited condensed consolidated financial statements reflect, in the opinion of management, all adjustments (consisting of normal recurring items) necessary for a fair statement, in all material respects, of the financial position and results of operations for the periods presented. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reported period. Actual results could differ materially from those estimates. The results of operations for the interim periods are not necessarily indicative of the results for the entire year.

Change in Estimate

Beginning in January 2017, we changed the method we use to calculate the service and interest cost components of net periodic benefit cost for our U.S. pension and other post-retirement benefit plans. Previously, we calculated the service and interest cost components using a single weighted-average discount rate derived from the yield curve to measure the benefit obligation at the beginning of the period. In 2017, we began using a full yield curve approach in the estimation of these components of benefit cost by applying the specific spot-rates along the yield curve to the relevant projected cash flows. This approach better aligns each of the projected benefit cash flows to the corresponding spot rates on the yield curve, resulting in a more precise measurement of service and interest costs. The change in method will result in a decrease in the service and interest components of pension costs in 2017. Any decrease to these components as a result of adoption of this approach is equally offset by a decrease in the actuarial losses included in our accumulated other comprehensive loss, with no impact on the measurement of the benefit obligation. This change is accounted for prospectively as a change in accounting estimate.

Subsequent Events

We have evaluated subsequent events and transactions for potential recognition or disclosure in the financial statements through the date the consolidated financial statements are issued.

NOTE 2 – Accounts Receivable
The components of accounts receivable are as follows:

	As of	
	June 30, 2017	December 31, 2016
Accounts receivable, gross	$66,918	$62,782
Less: Allowance for doubtful accounts	(181)	(170)

Accounts receivable, net	$66,737	$62,612

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NOTE 3 – Inventories

Inventories consist of the following:

	As of	
	June 30, 2017	December 31, 2016
Finished goods	$8,042	$7,513
Work-in-process	13,684	9,596
Raw materials	21,552	17,680
Less: Inventory reserves	(7,184)	(6,137)
Inventories, net	$36,094	$28,652

NOTE 4 – Property, Plant and Equipment

Property, plant and equipment is comprised of the following:

	As of	
	June 30, 2017	December 31, 2016
Land	$2,635	$2,330
Buildings and improvements	64,309	63,621
Machinery and equipment	220,995	213,198
Less: Accumulated depreciation	(202,765)	(197,038)
Property, plant and equipment, net	$85,174	$82,111
Depreciation expense for the six months ended June 30, 2017		$6,524
Depreciation expense for the six months ended June 30, 2016		$6,308

NOTE 5 – Retirement Plans

Pension Plans

Net pension income for our domestic and foreign plans was as follows:

	Three Months Ended		Six Months Ended	
	June 30, 2017	June 30, 2016	June 30, 2017	June 30, 2016
Net pension income	$(491)	$(402)	$(924)	$(794)

The components of net pension (income) expense for our domestic and foreign plans include the following:

	Domestic Pension Plans Three Months Ended		Foreign Pension Plans Three Months Ended	
	June 30, 2017	June 30, 2016	June 30, 2017	June 30, 2016
Service cost	$ —	$ 22	$ 12	$ 13
Interest cost	2,068	2,756	9	11
Expected return on plan assets (1)	(4,060)	(4,744)	(5)	7

Amortization of loss	1,446	1,498	39	35
(Income) expense, net	$ (546)	$ (468)	$ 55	$ 66

(1) Expected return on plan assets is net of expected investment expenses and certain administrative expenses.

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	Domestic Pension Plans Six Months Ended		Foreign Pension Plans Six Months Ended	
	June 30, 2017	June 30, 2016	June 30, 2017	June 30, 2016
Service cost	—	$ 44	$ 24	$ 25
Interest cost	4,136	5,512	17	22
Expected return on plan assets (1)	(8,121)	(9,488)	(10)	14
Amortization of loss	2,892	2,996	77	69
Other cost due to retirement	61	12	—	—
(Income) expense, net	(1,032)	(924)	108	130

(1) Expected return on plan assets is net of expected investment expenses and certain administrative expenses.

Other Post-retirement Benefit Plan

Net post-retirement expense for our other post-retirement plan includes the following components:

	Three Months Ended		Six Months Ended	
	June 30, 2017	June 30, 2016	June 30, 2017	June 30, 2016
Service cost	$—	$1	$1	$2
Interest cost	40	52	80	104
Amortization of gain	(25)	(37)	(50)	(75)
Post-retirement expense	$15	$16	$31	$31

NOTE 6 – Other Intangible Assets

Intangible assets consist of the following components:

	As of June 30, 2017		
	Gross Carrying Amount	Accumulated Amortization	Net Amount
Customer lists/relationships	$63,386	$ (31,972)	$ 31,414
Patents	10,319	(10,319)	—
Technology and other intangibles	44,093	(8,648)	35,445
In process research and development	2,200	—	2,200
Other intangible assets, net	$119,998	$ (50,939)	$ 69,059
Amortization expense for the three months ended June 30, 2017		$ 1,613	
Amortization expense for the six months ended June 30, 2017		$ 3,149	

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	As of December 31, 2016		
	Gross Carrying Amount	Accumulated Amortization	Net Amount
Customer lists/relationships	$63,386	$ (30,318)	$ 33,068
Patents	10,319	(10,319)	—
Technology and other intangibles	36,715	(7,613)	29,102
In process research and development	2,200	—	2,200
Other intangible assets, net	$112,620	$ (48,250)	$ 64,370
Amortization expense for the three months ended June 30, 2016		$ 1,522	
Amortization expense for the six months ended June 30, 2016		$ 2,617	

Amortization expense remaining for other intangible assets is as follows:

	Amortization expense
2017	$ 3,414
2018	6,756
2019	6,747
2020	6,747
2021	6,668
Thereafter	38,727
Total amortization expense	$ 69,059

NOTE 7 – Costs Associated with Exit and Restructuring Activities

Costs associated with exit and restructuring activities are recorded in the Condensed Consolidated Statement of Earnings as a separate component of Operating earnings.

Total restructuring charges, all related to the June 2016 Plan described below, were as follows:

	Three Months Ended	
	June 30, 2017	June 30, 2016
Restructuring charges	729	206

	Six Months Ended	
	June 30, 2017	June 30, 2016
Restructuring charges	1,507	206

In June 2016, we announced plans to restructure operations by phasing out production at our Elkhart facility by mid-2018 and transitioning it into a research and development center supporting our global operations ("June 2016 Plan"). Additional organizational changes will also occur in various other locations. The cost of the plan is expected to be approximately $12,300 and will impact approximately 230 employees. The total restructuring liability related to severance and other one-time benefit arrangements under the June 2016 Plan was $1,522 at June 30, 2017 and $1,739 at December 31, 2016. Additional costs related to line movements, equipment charges, and other costs will be expensed as incurred.

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The following table displays the planned restructuring charges associated with the June 2016 Plan as well as a summary of the actual costs incurred through June 30, 2017:

June 2016 Plan	Planned Costs	Actual costs incurred through June 30, 2017
Workforce reduction	3,075	2,687
Equipment relocation	7,925	1,522
Other charges	1,300	345
Total restructuring charges	12,300	4,554

In April 2014, we announced plans to restructure our operations and consolidate our Canadian operations into other existing facilities as part of our overall plan to simplify its business model and rationalize our global footprint ("April 2014 Plan"). These restructuring actions, which were completed during 2015, impacted approximately 120 positions. The remaining restructuring liability related to the April 2014 Plan was $441 at June 30, 2017 and $423 at December 31, 2016. The following table displays the restructuring liability activity for all plans for the six months ended June 30, 2017:

Combined Plans	
Restructuring liability at January 1, 2017	$2,162
Restructuring charges	1,507
Cost paid	(1,751)
Other activity (1)	45
Restructuring liability at June 30, 2017	$1,963

(1) Other activity includes the effects of currency translation and other charges that do not flow through restructuring expense.

NOTE 8 – Accrued Liabilities

The components of accrued liabilities are as follows:

	As of June 30, 2017	December 31, 2016
Accrued product related costs	$5,274	$ 5,556
Accrued income taxes	9,542	9,826
Accrued property and other taxes	1,615	1,917
Accrued professional fees	1,413	1,633
Dividends payable	1,318	1,309
Remediation reserves	18,357	18,176
Other accrued liabilities	4,694	7,291
Total accrued liabilities	$42,213	$ 45,708

NOTE 9 – Contingencies

Certain processes in the manufacture of our current and past products create by-products classified as hazardous waste. We have been notified by the U.S. Environmental Protection Agency, state environmental agencies, and in some cases, groups of potentially responsible parties, that we may be potentially liable for environmental contamination at several sites currently and formerly owned or operated by us. Some sites, such as Asheville, North Carolina and Mountain View, California, are designated National Priorities List sites under the U.S. Environmental Protection Agency's Superfund program. We reserve for probable remediation activities and for claims and proceedings against us with respect to other environmental matters. We record reserves on an undiscounted basis. In the opinion of management, based upon presently available information relating to such matters, adequate provision for probable and estimable costs have been recorded. We do not have any known environmental obligations where a loss is probable or reasonably possible of occurring for which we do not have a reserve, nor do we have any amounts for which we have not reserved because the amount of the loss cannot be reasonably estimated. Due to the inherent nature of environmental obligations, we cannot provide assurance that our ultimate environmental liability will not materially exceed the amount of its current reserve. Our reserve and disclosures will be adjusted accordingly if additional information becomes available in the future.

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A roll forward of remediation reserves included in accrued liabilities on the balance sheet is comprised of the following:

	June 30, 2017	December 31, 2016
Balance at beginning of period	$18,176	$ 20,603
Remediation expense	130	556
Net remediation reimbursements (payments)	51	(2,983)
Balance at end of the period	$18,357	$ 18,176

During the quarter ended June 30, 2017, we received a reimbursement of remediation costs under a cost-allocation agreement that we entered into with an unrelated party in the amount of $811. This reimbursement has been reflected in the net remediation reimbursements above.

Unrelated to the environmental claims described above, certain other claims are pending against us with respect to matters arising in the ordinary conduct of our business. Although the ultimate outcome of any potential litigation resulting from these claims cannot be predicted with certainty, and some may be disposed of unfavorably to us, we believe that adequate provision for anticipated costs have been established based upon all presently available information. Except as noted herein, we do not believe we have any pending loss contingencies that are probable or reasonably possible of having a material impact on our consolidated financial position, results of operations, or cash flows.

NOTE 10 - Debt

Long-term debt was comprised of the following:

	As of June 30, 2017	December 31, 2016
Revolving credit facility due in 2020	$92,800	$89,100
Weighted average interest rate	2.2 %	1.9 %
Amount available	$205,135	$208,735
Total credit facility	$300,000	$300,000
Standby letters of credit	$2,065	$2,165
Commitment fee percentage per annum	0.25 %	0.25 %

On August 10, 2015, we entered into a new five-year credit agreement (“Revolving Credit Facility”) with a group of banks in order to support our financing needs. The Revolving Credit Facility originally provided for a credit line of $200,000. On May 23, 2016, we requested and received a $100,000 increase in the aggregate revolving credit commitments under the existing credit agreement, which increased the credit line from $200,000 to $300,000.

The Revolving Credit Facility includes a swing line sublimit of $15,000 and a letter of credit sublimit of $10,000. Borrowings under the Revolving Credit Facility bear interest, at our option, at the base rate plus the applicable margin for base rate loans or LIBOR plus the applicable margin for LIBOR loans. We also pay a quarterly commitment fee on the unused portion of the Revolving Credit Facility. The commitment fee ranges from 0.20% to 0.40%Fair value of derivatives

14,983

11,725

Related to affiliated partnerships (3)

Fair value of derivatives

3,947

4,462

Related to natural gas marketing

Fair value of derivatives

11

7

30,349

29,998

Non Current

Commodity contracts

Related to natural gas and crude oil sales

Fair value of derivatives

9,171

6,231

Related to affiliated partnerships (3)

Fair value of derivatives

(25
)

(3
)

Related to natural gas marketing

Fair value of derivatives

(14
)

30

Basis protection contracts

Related to natural gas and crude oil sales

Fair value of derivatives

18,255

21,905

Related to affiliated partnerships (3)

Fair value of derivatives

4,844

8,481

Related to natural gas marketing

Fair value of derivatives

(1
)

—

32,230

36,644

Total derivative liabilities

$
62,579

$
66,642

(1) As of June 30, 2011, and December 31, 2010, none of our derivative instruments were designated as hedges.
(2) Our balance sheets include a corresponding payable to our affiliated partnerships of $14.0 million and $20.3 million as of June 30, 2011, and December 31, 2010, respectively.
(3) Our balance sheets include a corresponding receivable from our affiliated partnerships of $9.5 million and $14.6 million as of June 30, 2011, and December 31, 2010, respectively.

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PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - Continued

The following table presents the impact of our derivative instruments on our statements of operations.

Statement of operations line item	2011 Reclassification of Realized Gains (Losses) Included in Prior Periods Unrealized	2011 Realized and Unrealized Gains (Losses) For the Current Period	2011 Total	2010 Reclassification of Realized Gains (Losses) Included in Prior Periods Unrealized	2010 Realized and Unrealized Gains (Losses) For the Current Period	2010 Total
	(in thousands)					
Three Months Ended June 30,						
Commodity price risk management gain, net						
Realized gains	$763	$1,040	$1,803	$7,503	$390	$7,893
Unrealized gains (losses)	(763)	19,497	18,734	(7,503)	11,867	4,364
Total commodity price risk management gain, net (1)	$—	$20,537	$20,537	$—	$12,257	$12,257
Sales from natural gas marketing						
Realized gains (losses)	$473	$19	$492	$1,984	$(179)	$1,805
Unrealized gains (losses)	(473)	456	(17)	(1,984)	(580)	(2,564)
Total sales from natural gas marketing (2)	$—	$475	$475	$—	$(759)	$(759)
Cost of natural gas marketing						
Realized gains (losses)	$(370)	$(31)	$(401)	$(1,747)	$138	$(1,609)
Unrealized gains (losses)	370	(436)	(66)	1,747	664	2,411
Total cost of natural gas marketing (2)	$—	$(467)	$(467)	$—	$802	$802
Six Months Ended June 30,						
Commodity price risk management gain (loss), net						
Realized gains (losses)	$6,612	$(1,021)	$5,591	$21,604	$9,213	$30,817
Unrealized gains (losses)	(6,612)	(2,324)	(8,936)	(21,604)	46,266	24,662
Total commodity price risk management gain (loss), net (1)	$—	$(3,345)	$(3,345)	$—	$55,479	$55,479
Sales from natural gas marketing						
Realized gains	$1,373	$261	$1,634	$1,481	$1,383	$2,864
Unrealized gains (losses)	(1,373)	339	(1,034)	(1,481)	2,429	948
Total sales from natural gas marketing (2)	$—	$600	$600	$—	$3,812	$3,812
Cost of natural gas marketing						
Realized losses	$(1,076)	$(285)	$(1,361)	$(1,329)	$(1,376)	$(2,705)
Unrealized gains (losses)	1,076	(200)	876	1,329	(2,238)	(909)
Total cost of natural gas marketing (2)	$—	$(485)	$(485)	$—	$(3,614)	$(3,614)

(1) Represents realized and unrealized gains and losses on derivative instruments related to natural gas and crude oil sales.
(2) Represents realized and unrealized gains and losses on derivative instruments related to natural gas marketing.

Concentration of Credit Risk. We make extensive use of over-the-counter derivative instruments that enable us to manage a portion of our exposure to price volatility from producing and marketing natural gas and crude oil. These arrangements expose us to credit risk of nonperformance by our counterparties. We primarily use financial institutions, who are also major lenders in our credit facility agreement, as counterparties to our derivative contracts. To date, we have had no counterparty default losses. We have evaluated the credit risk of our derivative assets from our counterparties using relevant credit market default rates, giving consideration to amounts outstanding for each counterparty and the duration of each outstanding derivative position. Based on our evaluation, the impact of the nonperformance of our counterparties on the fair value of our derivative instruments was not significant.

PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - Continued

The following table presents the derivative counterparties that expose us to credit risk.

Counterparty Name	Fair Value of Derivative Assets As of June 30, 2011 (in thousands)
JPMorgan Chase Bank, N.A. (1)	$35,423
Crèdit Agricole CIB (1)	21,978
Wells Fargo Bank, N.A. (1)	12,998
Various (2)	2,944
Total	$73,343

(1)Major lender in our credit facility, see Note 7.
(2)Represents a total of 19 counterparties, including three lenders in our credit facility.

NOTE 5 - PROPERTIES AND EQUIPMENT

The following table presents the components of properties and equipment, net.

	June 30, 2011	December 31, 2010
	(in thousands)	
Properties and equipment, net:		
Natural gas and crude oil properties		
Proved	$1,599,926	$1,429,667
Unproved	72,663	79,053
Total natural gas and crude oil properties	1,672,589	1,508,720
Pipelines and related facilities	34,110	34,262
Transportation and other equipment	33,209	32,410
Land, buildings and leasehold improvements	14,514	13,379
Construction in progress	63,351	42,128
	1,817,773	1,630,899
Accumulated DD&A	(573,360)	(510,861)
Properties and equipment, net	$1,244,413	$1,120,038

NOTE 6 - INCOME TAXES

We evaluate our estimated annual effective income tax rate on a quarterly basis based on current and forecasted operating results and enacted tax laws. The estimated annual effective tax rate is adjusted quarterly based upon actual results and updated operating forecasts; consequently, based upon the mix and timing of our actual earnings compared to annual projections, our effective tax rate may vary quarterly and may make quarterly comparisons not meaningful. A tax expense or benefit unrelated to the current year income or loss is recognized in its entirety as a discrete item of tax in the period identified. The quarterly income tax provision is generally comprised of tax on income or tax benefit on loss at the most recent estimated annual effective tax rate, adjusted for the effect of discrete items.

The effective tax rate for continuing operations for the three and six months ended 2011 was 27.2% (provision on income) and 43.8% (benefit on loss), respectively, compared to 36.1% (benefit on loss) and 37.7% (provision on income) for the three and six months ended 2010, respectively. Since our full year forecasted loss is less than our loss for the six months ended 2011, the amount of tax benefit we can record on our year to date loss is limited. The tax benefit limitation for the six months ended 2011 was $1.9 million compared to a $1.5 million limitation for the three months ended March 31, 2011. The effective tax rate for the six months ended 2010 was for a provision on income, not a tax benefit on loss, therefore there was no limitation affecting the 2010 rate. The effective tax rate differs from the statutory rate primarily due to net permanent deductions, largely percentage depletion, increasing the tax benefit on loss for this six month-period, while decreasing the tax provision on pretax income for the same prior year period. During the three months ended 2011, we recorded a net discrete tax benefit of $0.6 million primarily due to a reduction of our liability for uncertain tax benefits.

As of June 30, 2011, we had a gross liability for unrecognized tax benefits of $0.6 million compared to $1.1 million at December 31, 2010. If recognized, $0.5 million of this liability would affect our effective tax rate. This liability is reflected in other accrued expenses on our accompanying balance sheet. In July 2011, the Internal Revenue Service ("IRS") completed its examination of our 2007, 2008 and 2009 tax years. During the three months ended 2011, we reduced our liability by $0.6 million for uncertain tax benefits that were resolved without change by the completion of the IRS examination and reduced the liability by $0.1 million due to the expiration of the statute of limitations

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related to another tax position. During the six months ended 2011, we increased the liability by $0.2 million for tax positions of the current year. We expect our remaining liability for uncertain tax positions to decrease in the next 12 months as a remaining uncertain tax position is reviewed under the IRS Compliance Assurance Process.

As of the date of this filing, we are current with our income tax filings in all applicable state jurisdictions and currently have no state income tax returns in the process of examination.

NOTE 7 - LONG-TERM DEBT

Long-term debt consists of the following:

	June 30, 2011	December 31, 2010
	(in thousands)	
Senior notes		
3.25% Convertible senior notes due 2016:		
Principal amount	$115,000	$115,000
Unamortized discount	(18,368)	(20,252)
3.25% Convertible senior notes due 2016, net of discount	96,632	94,748
12% Senior notes due 2018:		
Principal amount	203,000	203,000
Unamortized discount	(1,908)	(2,053)
12% Senior notes due 2018, net of discount	201,092	200,947
Total senior notes	297,724	295,695
Credit facilities		
Corporate	8,500	—
PDCM	7,900	—
Total credit facilities	16,400	—
Total long-term debt	$314,124	$295,695

Senior Notes

3.25% Convertible Senior Notes Due 2016. In November 2010, we issued $115 million of 3.25% convertible senior notes due 2016 in a private placement. The maturity for the payment of principal is May 15, 2016. Interest at the rate of 3.25% per year is payable in cash semiannually in arrears on each May 15 and November 15, which commenced on May 15, 2011. We allocated the gross proceeds of the convertible notes between the liability and equity components of the debt. The initial $94.3 million liability component was determined based on the fair value of similar debt instruments, excluding the conversion feature, with similar terms and priced on the same day we issued our convertible notes. The original issue discount and the deferred note issuance costs are being amortized to interest expense over the term of the debt using an effective interest rate of 7.4%. Upon conversion, the convertible notes may be settled, at our election, in shares of our common stock, cash or a combination of cash and shares of our common stock. We have initially elected a net-settlement method to satisfy our conversion obligation, which allows us to settle the $1,000 principal amount of the convertible notes in cash and to settle the excess conversion value in shares, as well as cash in lieu of fractional shares.

12% Senior Notes Due 2018. In 2008, we issued $203 million of 12% senior notes due 2018 in a private placement. The maturity for the payment of principal is February 15, 2018. Interest at the rate of 12% per year is payable in cash semiannually in arrears on each February 15 and August 15. The senior notes were issued at a discount, 98.572% of the principal amount. The indenture governing the notes contains customary representations and warranties as well as typical restrictive covenants. The original issue discount and the deferred note issuance costs are being amortized to interest expense over the term of the debt using the effective interest method.

We were in compliance with all covenants related to our senior notes as of June 30, 2011, and expect to remain in compliance throughout the next twelve-month period.

Bank Credit Facilities

Corporate Bank Credit Facility. We operate under a credit facility dated as of November 5, 2010, as amended last on May 6, 2011, with an aggregate revolving commitment or borrowing base of $350 million. The maximum allowable facility amount is $600 million. The credit facility is with certain commercial lending institutions and is available for working capital requirements, capital expenditures, acquisitions, general corporate purposes and to support letters of credit.

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Our credit facility borrowing base is subject to size redetermination semiannually based on a valuation of our natural gas and crude oil reserves at December 31 and June 30 and is also subject to a redetermination upon the occurrence of certain events. The borrowing base of the credit facility will be the loan value assigned to the proved reserves attributable to our natural gas and crude oil interests, excluding proved reserves attributable to PDCM and our 26 affiliated partnerships. The credit facility is secured by a pledge of the stock of certain of our subsidiaries, mortgages of certain producing natural gas and crude oil properties and substantially all of our other assets. Neither PDCM nor the various limited partnerships that we have sponsored and continue to serve as the managing general partner are guarantors of the credit facility.

Our outstanding principal amount accrues interest at a varying interest rate that fluctuates with an alternate base rate (equal to the greater of JPMorgan Chase Bank, N.A.'s prime rate, the federal funds rate plus a premium and 1-month LIBOR plus a premium), or at our election, a rate equal to the rate for dollar deposits in the London interbank market for certain time periods. Additionally, commitment fees, interest margin and other bank fees, charged as a component of interest, vary with our utilization of the facility. No principal payments are required until the credit agreement expires on November 5, 2015, or in the event that the borrowing base would fall below the outstanding balance. The credit facility contains covenants customary for agreements of this type.

Through May 26, 2011, we had outstanding an undrawn $18.7 million irrevocable standby letter of credit in favor of a third party transportation service provider. This letter of credit reduced the amount of available funds under our credit facility by an equal amount. We paid a fronting fee of 0.125% per annum and an additional quarterly maintenance fee equivalent to the spread over Eurodollar loans (2.0% per annum as of May 26, 2011) for the period the letter of credit remained outstanding. The letter of credit was originally set to expire on May 22, 2012. On May 27, 2011, we were required to replace the original letter of credit with a new letter of credit. As of June 30, 2011, for administrative reasons, the new letter of credit was not yet final; however, it was completed and outstanding as of July 25, 2011, and therefore has been included in this report as if outstanding, but undrawn, for available liquidity calculations as of June 30, 2011. There were no significant changes from the original letter of credit.

As of June 30, 2011, we had drawn $8.5 million from our credit facility compared to no outstanding draws as of December 31, 2010. We pay a fee of 0.5% per annum on the unutilized commitment on the available funds under our credit facility. As of June 30, 2011, the available funds under our credit facility, assuming the $18.7 million irrevocable standby letter of credit was in effect, were $322.8 million. The weighted average borrowing rate on our credit facility was 0.7% per annum as of June 30, 2011.

PDCM Credit Facility. PDCM has a credit facility dated as of April 30, 2010, as amended on April 20, 2011, with an aggregate revolving commitment or borrowing base of $40 million. In addition to the increase in borrowing base, the first amendment permits PDCM to enter into swap agreements on new properties which were not included in the most recent reserve report and which have been producing for at least 30 days. The credit facility is subject to and secured by PDCM's properties, including our proportionate share of such properties. The credit facility borrowing base is subject to size redetermination semiannually based upon a valuation of PDCM's reserves at December 31 and June 30; further, either PDCM or the lenders may request a redetermination upon the occurrence of certain events. Pursuant to the interests of the joint venture, the credit facility will be utilized by PDCM for the exploration and development of its Appalachian assets. As of June 30, 2011, PDCM had drawn $15 million from its credit facility, of which our proportionate share was $7.9 million. As of December 31, 2010, there were no amounts outstanding related to this credit facility. The weighted average borrowing rate on PDCM's credit facility was 1.8% per annum as of June 30, 2011.

As of June 30, 2011, both the Company and PDCM were in compliance with all bank credit facility covenants and expect to remain in compliance throughout the next twelve-month period.

NOTE 8 - ASSET RETIREMENT OBLIGATIONS

The following table presents the changes in carrying amounts of the asset retirement obligations associated with our working interest in natural gas and crude oil properties.

	Amount (in thousands)	
Balance at December 31, 2010 (1)	$28,047	
Change in ownership interest of PDCM	(485	)
Obligations incurred with development activites and assumed with acquisitions	847	
Accretion expense	798	
Obligations discharged with disposal of properties and asset retirements	(221	)
Revisions in estimated cash flows	(322	)
Balance at June 30, 2011	28,664	
Less current portion	(250	)
Long-term portion	$28,414	

(1) Includes $0.2 million as of December 31, 2010, related to assets held for sale.

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NOTE 9 - COMMITMENTS AND CONTINGENCIES

Merger Agreements. On June 20, 2011, pursuant to our previously announced partnership acquisition plan, we entered into separate merger agreements with five of our affiliated partnerships: PDC 2003-A Limited Partnership, PDC 2003-B Limited Partnership, PDC 2003-C Limited Partnership, PDC 2003-D Limited Partnership and PDC 2002-D Limited Partnership (collectively, the "2003/2002-D Partnerships"). We serve as the managing general partner of each of the 2003/2002-D Partnerships. Pursuant to each merger agreement, if the merger is approved by the holders of a majority of the limited partnership units held by limited partners of that partnership not owned by us (the "non-affiliated investor partners"), as well as the satisfaction of other customary closing conditions, then we will acquire such partnerships. If all five partnerships are acquired, we expect to pay an aggregate of approximately $29.5 million to the non-affiliated investor partners for the limited partnership units of these partnerships. On June 23, 2011, we filed the preliminary proxy statements with the SEC and anticipate, upon clearance by the SEC, that the definitive proxy statements are anticipated to be mailed to investors in August 2011. If the required approvals are received, we expect the mergers to be completed in the fourth quarter of 2011. We expect to finance the acquisition of the 2003/2002-D Partnerships by borrowing funds under our revolving credit facility. There can be no assurance that we will be successful in the acquisition of the 2003/2002-D Partnerships, individually or collectively, or on terms acceptable to us.

Drilling Rig Contract. In order to secure the services of a drilling rig, in August 2010, PDCM entered into a commitment with a drilling contractor for the services of a drilling rig. The commitment expires in October 2012. During the first quarter of 2011, included in production costs in the statement of operations, we recorded a charge of $0.5 million related to our proportionate share of rig laydown costs. As of June 30, 2011, our proportionate share of PDCM's related maximum commitment through October 2012 was $4.5 million.

Firm Transportation Agreements. We have entered into contracts that provide firm transportation, sales and processing charges on pipeline systems through which we transport or sell our natural gas and the natural gas of working interest owners, PDCM, our affiliated partnerships and other third parties. These contracts require us to pay these transportation and processing charges whether the required volumes are delivered or not. Satisfaction of the volume requirements includes volumes produced by us, volumes purchased from third parties and volumes produced by our joint venture and affiliated partnerships. We record in our financial statements only our share of costs based upon our working interest in the wells; however, the costs of all volume shortfalls will be borne by PDC.

As of June 30, 2011, we have a liability in the amount of $3.1 million included in other liabilities on the balance sheet related to an agreement in the Piceance Basin. On July 27, 2011, we entered into an amendment with the unrelated third party subject to this agreement and as a result, the accrued liability as of June 30, 2011, will be reduced during the third quarter of 2011 with no cash payment by us required. The amendment did not extend the expiration date of the original agreement. The table below does not include the impact of this amendment. Including the impact of this amendment, our volume requirements for the Piceance Basin would be 18,000 MMcf, 19,814 MMcf, 39,252 MMcf, 33,201 MMcf and 126,265 MMcf for the 12 months ending June 30, 2012, 2013, 2014, 2015 and 2016 through expiration, respectively, for a total of 236,532 MMcf.

The following table presents gross volume information, including our proportionate share of PDCM, related to our long-term firm sales, processing and transportation agreements for pipeline capacity.

	For the Twelve Months Ending June 30,					
Area	2012	2013	2014	2015		Total

					2016 Through Expiration		Expiration Date
Volume (MMcf)							
Piceance Basin	32,613	32,577	28,182	22,131	60,759	176,262	May 31, 2021
Appalachian Basin (1)	5,150	14,324	15,992	15,992	110,665	162,123	August 31, 2022
NECO	2,745	1,825	1,825	1,825	2,745	10,965	December 31, 2016
Total	40,508	48,726	45,999	39,948	174,169	349,350	
Dollar commitment (in thousands)	$19,867	$24,118	$22,704	$19,527	$82,171	$168,387	

(1) Includes a precedent agreement that becomes effective when a planned pipeline is placed in service, currently expected to be September 2012 and represents 8,823 MMcf of the total MMcf presented for the year ending June 30, 2013, 10,629 MMcf for each of the years ending June 30, 2014 and 2015, respectively, and 76,265 MMcf thereafter. This agreement will be null and void if the pipeline is not completed. In August 2009, we issued a letter of credit related to this agreement, see Note 7.

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Litigation. The Company is involved in various legal proceedings that it considers normal to its business. The Company reviews the status of these proceedings on an ongoing basis and, from time to time, may settle or otherwise resolve these matters on terms and conditions that management believes are in the best interests of the Company. There are no assurances that settlements can be reached on acceptable terms or that adverse judgments, if any, in the remaining litigation will not exceed the amounts reserved. Although the results cannot be known with certainty, we currently believe that the ultimate results of such proceedings will not have a material adverse effect on our financial position, results of operations or liquidity.

Royalty Owner Class Action

Gobel et al v. Petroleum Development Corporation, filed on January 27, 2009, in Circuit Court of Harrison County, CA No. 09-C-40-2

David W. Gobel, individually and allegedly as representative of all royalty owners in the Company's West Virginia oil and gas wells, filed a lawsuit against the Company alleging that we failed to properly pay royalties. The allegations stated that the Company improperly deducted certain charges and costs before applying the royalty percentage. Punitive damages were requested in addition to breach of contract, tort and fraud allegations. On October 27, 2010, the state court set a trial date of April 2012.

In April 2011, the Company entered into an oral settlement agreement with respect to this lawsuit, settling all claims between the parties for an aggregate payment of $8.7 million. On June 15, 2011, a written settlement agreement was signed confirming these terms and on June 30, 2011, the state court granted initial approval of the settlement agreement, subject to notice to class members and final court approval. As of June 30, 2011, the total settlement amount of $8.7 million was accrued and included in other accrued expenses on the accompanying balance sheet. A related escrow account was fully funded on July 22, 2011.

Environmental. Due to the nature of the natural gas and oil industry, we are exposed to environmental risks. We have various policies and procedures in place to avoid environmental contamination and mitigate the risks from environmental contamination. We conduct periodic reviews to identify changes in our environmental risk profile. Liabilities are accrued when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated. As of June 30, 2011, and December 31, 2010, we had accrued environmental liabilities in the amount of $2.3 million and $1.7 million, respectively, included in other accrued expenses on the balance sheet. We are not currently aware of any environmental claims existing as of June 30, 2011, which have not been provided for or would otherwise have a material impact on our accompanying financial statements. However, there can be no assurance that current regulatory requirements will not change or unknown past non-compliance with environmental laws will not be discovered on our properties.

Partnership Repurchase Provision. Substantially all of our drilling programs contain a repurchase provision where investing partners may request that we purchase their partnership units at any time beginning with the third anniversary of the respective partnership's first cash distribution. The provision provides that we are obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months' cash distributions from production), if repurchase is requested by investors, subject to our financial ability to do so. As of June 30, 2011, the maximum annual repurchase obligation, based upon the minimum price described above, was approximately $5 million. We believe we have adequate liquidity to meet this obligation. For the six months ended 2011, amounts paid for the repurchase of partnership units pursuant to this provision were immaterial.

Employment Agreements with Executive Officers. With the exception of our Chief Executive Officer, we have employment agreements with our executive officers. The employment agreements provide for annual base salaries, eligibility for performance bonus compensation and other various benefits, including severance benefits. We are currently in the process of preparing an employment agreement with our Chief Executive Officer.

If, within two years following a change of control of the Company ("change in control period"), either the Company terminates the executive officer without cause or the executive officer terminates employment for good reason (what is referred to as a "double trigger"), then the severance benefits owed equals three times the sum of the executive's highest annual base salary during the previous two years of employment immediately preceding the termination date and the executive's highest annual bonus paid or, in the case of one executive officer, paid or payable during the same two-year period. For one executive, in this calculation, the target bonus will be used as the minimum value for the first two years of employment. Where the Company terminates the executive officer without cause or the executive officer terminates employment for good reason outside of the change in control period, the severance benefits range from two times to three times, specific to the executive officer, the benefits noted above. For this purpose, a change of control and good reason correspond to the respective definitions of change of control and good reason under Internal Revenue Code ("IRC") 409A and the supporting Treasury regulations, with some differences. Under any of the above circumstances, the executive officer is also entitled under his employment agreement to (i) vesting of any unvested equity compensation (excluding all long-term incentive shares), (ii) reimbursement for any unpaid expenses, (iii) retirement benefits earned under the current and/or previous agreements, (iv) continued coverage under our medical plan at the Company's cost for the federal COBRA health continuation coverage period and (v) payment of any earned and unpaid bonus amounts. In addition, the executive officer is entitled to receive any benefits that he would have otherwise been entitled to receive under our qualified retirement plan, although those benefits are not increased or accelerated.

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In the event that an executive officer is terminated for just cause, we are required to pay the executive officer his base salary through the termination date plus a partial year bonus, incentive, deferred, retirement or other compensation and to provide any other benefits, which have been earned or become payable as of the termination date.

In the event that an executive officer voluntarily terminates his employment for other than good reason, he is entitled to receive (i) his base salary and bonus, provided, however, that with respect to the bonus, for certain executive officers, there will be no proration of the bonus if such executive leaves prior to the last day of the year and, with respect to one executive officer, there will be no proration of the bonus in the event such executive officer leaves prior to March 31 in the year of his termination, (ii) any incentive, deferred or other compensation which has been earned or has become payable, but which has not yet been paid under the schedule originally contemplated in the agreement under which they were granted, (iii) any unpaid expense reimbursement and (iv) any other payments for benefits earned under the employment agreement or our plans.

In the event of death or disability, the executive is entitled to receive certain benefits. For this purpose, the definition of "disability" corresponds to the definition under IRC 409A and the supporting Treasury regulations. The benefits will (i) in the case of death be paid in a lump sum and be equal to the base salary that would otherwise have been paid for a six-month period following the termination date and (ii) in the case of disability be up to thirteen weeks of ongoing base salary plus a lump sum equal to six months of base salary.

See Note 13 for a discussion related to the separation agreement entered into with our former chief executive officer during the three months ended 2011.

Partnership Casualty Losses. As Managing General Partner of numerous partnerships, we have a potential liability for casualty losses in excess of the partnership assets and insurance. We believe the casualty insurance coverage that we and our subcontractors carry is adequate to meet this potential liability.

NOTE 10 - COMMON STOCK

Stock-Based Compensation Plans

The following table provides a summary of the impact of our outstanding stock-based compensation plans on the results of operations for the periods presented.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011 (1)	2010	2011 (1)	2010
	(in thousands)			
Total stock-based compensation expense	$4,004	$1,216	$5,549	$2,221
Income tax benefit	(1,521)	(467)	(2,108)	(852)
Net income (loss) impact	$2,483	$749	$3,441	$1,369

(1) Includes a total of $2.5 million, pretax, related to a separation agreement with our former chief executive officer.

Stock Appreciation Rights ("SARs")

In March 2011, the Compensation Committee of our Board of Directors (the "Compensation Committee") awarded 31,552 SARs to our executive officers. The SARs will vest ratably over a three-year period and may be exercised at any point after vesting through March 2021. Pursuant to the terms of the awards, upon exercise, the executives will receive, in shares of common stock, the excess of the market price of the award on the date of exercise over the market price of the award on the date of issuance.

The fair value of each SAR award was estimated on the date of grant using a Black-Scholes pricing model using the assumptions presented in the table below. The expected life of the award was estimated using historical stock option exercise behavior data. The risk-free interest rate was based on the U.S. Treasury yields approximating the expected life of the award in effect at the time of grant. Expected volatilities were based on our historical volatility. We do not expect to pay dividends, nor do we expect to declare dividends in the foreseeable future.

	Six Months Ended June 30, 2011	
Expected term of the award	6 years	
Risk-free interest rate	2.5	%
Volatility	60.2	%
Weighted average grant date fair value per share	$25.22	

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The following table presents the changes in our SARs for the six months ended 2011.

	Number of Shares Underlying SARs	Grant Date Market Price Per Share	Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at December 31, 2010	57,282	$24.44	9.3	$—
Awarded	31,552	43.95	9.7	—
Outstanding at June 30, 2011	88,834	31.37	5.3	313
Vested and expected to vest at June 30, 2011	84,851	31.27	5.0	302
Exercisable at June 30, 2011	48,999	29.61	2.1	197

Pursuant to a separation agreement with our former chief executive officer and the original terms of the award, during the three months ended 2011, 29,906 SARs were accelerated to vest, resulting in the acceleration of $0.6 million in stock-based compensation expense. The total compensation cost related to SARs granted and not yet recognized in our statement of operations as of June 30, 2011, was $0.6 million. The cost is expected to be recognized over a weighted average period of 1.8 years.

Restricted Stock Awards

Time-Based Awards. In March 2011, the Compensation Committee awarded a total of 43,256 time-based restricted shares to our executive officers that vest ratably over a three-year period ending on March 12, 2014. In June 2011, the Compensation Committee awarded 58,122 time-based restricted shares to our new chief executive officer that vest ratably over a three-year period ending on June 10, 2014, and 21,798 time-based restricted shares to our non-employee directors that vest ratably over a three-year period ending on July 1, 2014.

Pursuant to a separation agreement with our former chief executive officer and the original terms of the award, during the three months ended 2011, the vesting of 64,442 time-based restricted shares was accelerated, resulting in the acceleration of $1.9 million in stock-based compensation expense. The total compensation cost related to non-vested time-based awards expected to vest and not yet recognized in our statements of operations as of June 30, 2011, was $10.0 million. This cost is expected to be recognized over a weighted average period of 2.1 years.

The following table presents the changes in non-vested time-based awards for the six months ended 2011.

	Shares	Weighted Average Grant-Date Fair Value per Share
Non-vested at December 31, 2010	525,715	$25.53
Granted	149,365	37.42
Vested	(183,639)	28.37
Forfeited	(13,580)	24.51
Non-vested at June 30, 2011	477,861	28.18

	As of / Six Months Ended June 30, 2011 (in thousands, except per share data)
Total intrinsic value of time-based awards vested	$7,185
Total intrinsic value of time-based awards non-vested	14,293
Market price per common share	29.91

Market-Based Awards. The fair value of the market-based restricted shares is amortized ratably over the requisite service period, primarily three years. Generally, the market-based shares vest if the participant is continuously employed throughout the performance period and the market-based performance measure is achieved, with a maximum vesting period of five years. All compensation cost related to the market-based awards will be recognized if the requisite service period is fulfilled, even if the market condition is not achieved.

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In March 2011, the Compensation Committee awarded a total of 13,531 market-based restricted shares to our executive officers. In addition to continuous employment, the vesting of these shares is contingent on the Company's total shareholder return ("TSR"), which is essentially the Company’s stock price change including any dividends, as compared to the TSR of a set group of 11 peer companies. The shares are measured over a three-year period ending on December 31, 2013, and can result in a payout between zero and 200% of the total shares awarded. The weighted average grant date fair value per market-based share for these awards granted was computed using the Monte Carlo pricing model using the weighted average assumptions presented in the table below.

	Six Months Ended June 30, 2011	
Expected term of award	3 years	
Risk-free interest rate	1.1	%
Volatility	74.2	%
Weighted average grant date fair value per share	$58.53	

Expected volatility was based on a blend of our historical and implied volatility. The expected lives of the awards were based on the requisite service period. The risk-free interest rate was based on the U.S. Treasury yields in effect at the time of grant or modification and extrapolated to approximate the life of the award. We do not expect to pay dividends, nor do we expect to declare dividends in the foreseeable future.

The following table presents the change in non-vested market-based awards for the six months ended 2011.

	Shares	Weighted Average Grant-Date Fair Value per Share
Non-vested at December 31, 2010	79,550	$32.52
Granted	13,531	58.53
Vested	(4,109)	6.47
Forfeited	(21,927)	34.32
Non-vested at June 30, 2011	67,045	38.78

Pursuant to a separation agreement with our former chief executive officer and the original terms of the award, during the three months ended 2011, the vesting of 4,109 market-based restricted shares was accelerated and 21,927 market-based restricted shares were forfeited. The impact on stock-based compensation for the vesting and forfeiture of these market-based restricted shares was immaterial. The total compensation cost related to non-vested market-based awards expected to vest and not yet recognized in our statement of operations as of June 30, 2011, was $0.4 million. This cost is expected to be recognized over a weighted average period of 2.5 years.

Treasury Share Purchases

In accordance with our stock-based compensation plans, employees and directors may surrender shares of the Company's common stock to cover tax withholding obligations upon the vesting and exercise of share-based awards. The shares acquired may be retired or reissued to service awards under our 2010 Long-Term Equity Compensation Plan (the "2010 Plan"). For shares that are retired, we first charge any excess of cost over the par value to additional paid-in-capital ("APIC") to the extent we have amounts in APIC, with any remaining excess cost charged to retained earnings. For shares reissued to service awards under the 2010 Plan, shares are recorded at cost and upon reissuance, we reduce the carrying value of shares acquired and held pursuant to the 2010 Plan by the weighted average cost per share with an offsetting charge to APIC. During the six months ended June 30, 2011, we acquired 38,635 shares pursuant to our stock-based compensation plans for payment of tax liabilities, of which 35,335 shares were retired.

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NOTE 11 - EARNINGS PER SHARE

The following is a reconciliation of weighted average diluted shares outstanding.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in thousands)			
Weighted average common shares outstanding - basic	23,491	19,213	23,460	19,202
Dilutive effect of share-based compensation:				
Restricted stock	181	—	—	86
SARs	48	—	—	—
Non employee director deferred compensation	3	—	—	8
Weighted average common and common share equivalents outstanding - diluted	23,723	19,213	23,460	19,296

The following table sets forth the weighted average common share equivalents excluded from the calculation of diluted earnings per share due to their anti-dilutive effect.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in thousands)			
Weighted average common share equivalents excluded from diluted earnings per share due to their anti-dilutive effect:				
Restricted stock	102	434	587	181
Stock options	10	10	10	10
SARs	32	57	77	57
Non employee director deferred compensation	—	8	3	—
Total anti-dilutive common share equivalents	144	509	677	248

In November 2010, we issued 115,000 convertible senior notes, $1,000 principal amount, that give the holders the right to convert the principal amount into 2.7 million common shares at a conversion price of $42.40 per share. The convertible notes could have a dilutive impact on our earnings per share if the average market share price exceeds the conversion price. The table above does not include those shares issuable upon conversion as the average share price of our common stock did not exceed the conversion price during the three and six months ended 2011.

NOTE 12 - DIVESTITURES AND DISCONTINUED OPERATIONS

North Dakota. During the fourth quarter of 2010, we developed a plan to divest our North Dakota assets. The plan included 100% of our North Dakota assets, consisting of producing wells, undeveloped leaseholds and related facilities primarily located in Burke County. The plan received our Board of Directors' (the "Board") approval and, in December 2010, we effected a letter of intent with an unrelated third party. Following the sale to the unrelated party, we do not have significant continuing involvement in the operations of or cash flows from these assets; accordingly, the North Dakota assets were reclassified as held for sale as of December 31, 2010, and the results of operations related to those assets have been separately reported as discontinued operations in the accompanying financial statements for all periods presented. In February 2011, we executed a purchase and sale agreement and subsequently closed with the same unrelated party. Proceeds from the sale were $9.5 million, net of non-affiliated investor partners' share of $3.8 million, resulting in a pretax gain on sale of $3.9 million.

Selected financial information related to divested and discontinued operations. The table below presents selected operational information related to discontinued operations. While the reclassification of revenues and expenses related to discontinued operations for prior period had no impact upon previously reported net earnings, the statement of operations and operational data present the revenues, expenses and production volumes that were reclassified from the specified statement of operations line items to discontinued operations.

The following table presents statement of operations data related to our discontinued operations. There was no activity recorded for discontinued operations for the three months ended 2011. The three and six months ended 2010, in addition to the discontinued operations data of our North Dakota assets, includes operations data related to the July 2010 divestiture of our Michigan assets.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - Continued

Statement of Operations - Discontinued Operations	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	2010
	(dollars in thousands)		
Revenues			
Natural gas, NGL and crude oil sales	$1,995	$447	$4,536
Sales from natural gas marketing	1,136	—	2,760
Well operations, pipeline income and other	146	10	402
Total revenues	3,277	457	7,698
Costs, expenses and other			
Production costs	864	132	1,579
Cost of natural gas marketing	1,197	—	2,728
Impairment of proved natural gas and oil properties	4,506	—	4,506
Depreciation, depletion and amortization	533	—	1,464
Gain on sale of properties and equipment	—	(3,854)	—
Total costs, expenses and other	7,100	(3,722)	10,277
Income (loss) from discontinued operations	(3,823)	4,179	(2,579)
Provision (benefit) for income taxes	(1,510)	1,559	(1,063)
Income (loss) from discontinued operations, net of tax	$(2,313)	$2,620	$(1,516)
Operational Data			
Production			
Natural gas (MMcf)	354.3	8.7	722.8
Crude oil (MBbls)	10.6	3.9	22.6
Natural gas equivalent (MMcfe)	417.6	32.1	858.0

NOTE 13 - TRANSACTIONS WITH AFFILIATES AND OTHER RELATED PARTIES

On June 10, 2011, Richard W. McCullough resigned from his positions as our Chief Executive Officer and the Chairman of the Board, effective immediately. In connection with his resignation, on July 12, 2011, Mr. McCullough and the Company executed a separation agreement, whereby Mr. McCullough will receive those benefits to which he was entitled under Section 7(d) of his employment agreement, dated as of April 19, 2010, including without limitation: (i) separation compensation in the amount of $4.1 million, less required withholdings; (ii) his annual non-qualified deferred supplemental retirement benefit equal to $30,000 for each of the years 2012 through 2021 (not accelerated), less required withholdings; (iii) continued coverage under the Company's group health plans at the Company's cost for a period equal to the lesser of 18 months or such period ending as of the date Mr. McCullough is eligible to participate in another employer's group health plan; (iv) immediate vesting of any unvested Company stock options, stock appreciation rights and restricted stock; and (v) issuance of shares representing the vested portion of his 2009 performance share awards. Related to this separation agreement, the statements of operations for the three and six months ended 2011 reflect a charge to general and administrative expense of $6.7 million.

Amounts due from/to the affiliated partnerships are primarily related to derivative positions and, to a lesser extent, unbilled well lease operating expenses, and costs resulting from audit and tax preparation services. We enter into derivative instruments for our own production as well as for our 26 affiliated partnerships' production. As of June 30, 2011, we had a payable to affiliates of $14.0 million representing their designated portion of the fair value of our gross derivative assets and a receivable from affiliates of $9.5 million representing their designated portion of the fair value of our gross derivative liabilities.

Our natural gas marketing segment manages the marketing of natural gas for PDCM and our affiliated partnerships with production in the Appalachian Basin. Our sales from natural gas marketing include $3.8 million and $5.8 million for the three and six months ended 2011, respectively, and $1.1 million and $2.2 million for three and six months ended 2010, respectively, related to the marketing of natural gas on behalf of PDCM and our affiliated partnerships. Our cost of natural gas marketing includes $3.7 million and $5.7 million for the three and six months ended 2011, respectively, and $1.0 million and $2.1 million for the three and six months ended 2010, respectively, related to these sales.

We provide certain well operating and administrative services for PDCM. Amounts billed to PDCM for these services were $1.8 million and $4.5 million in the three and six months ended 2011, respectively, and $2.7 million and $5.6 million for the three and six months ended 2010, respectively. Our statements of operations include only our proportionate share of these billings. The following table presents the statement of operations line item in which our proportionate share is recorded and the amount for each of the periods present.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - Continued

Statement of Operations Line Item	Three Months Ended June 30, 2011	2010	Six Months Ended June 30, 2011	2010
	(in millions)			
Production costs	$0.6	$0.9	$1.5	$1.9
Exploration expense	0.1	0.2	0.2	0.5
General and administrative expense	0.3	0.5	0.7	1.2

We provide well operations and pipeline services to our affiliated partnerships. The majority of our revenue and expenses related to well operations and pipeline income are associated with services provided to our affiliated partnerships.

NOTE 14 - BUSINESS SEGMENTS

We separate our operating activities into two segments: natural gas and crude oil sales and natural gas marketing. All material inter-company accounts and transactions between segments have been eliminated.

The following tables present our segment information.

	Three Months Ended June 30, 2011	2010	Six Months Ended June 30, 2011	2010
	(in thousands)			
Revenues:				
Natural gas and crude oil sales	$94,533	$63,138	$136,406	$166,773
Natural gas marketing	18,897	12,588	34,099	35,275
Unallocated	—	(3)	—	—
Total	$113,430	$75,723	$170,505	$202,048
Segment income (loss) before income taxes:				
Natural gas and crude oil sales	$41,235	$17,206	$28,325	$72,860
Natural gas marketing	690	373	899	730
Unallocated	(29,344)	(18,239)	(53,034)	(37,574)
Total	$12,581	$(660)	$(23,810)	$36,016

	June 30, 2011	December 31, 2010
	(in thousands)	
Segment assets:		
Natural gas and crude oil sales	$1,376,711	$1,313,805
Natural gas marketing	12,688	16,338
Unallocated	54,286	53,701
Assets held for sale	—	5,191
Total	$1,443,685	$1,389,035

NOTE 15 - ACQUISITION

2005 Partnerships. On June 15, 2011, we acquired the remaining working interest in three of our affiliated partnerships: PDC 2005-A Limited Partnership, PDC 2005-B Limited Partnership and Rockies Region Private Limited Partnership ("2005 Partnerships"). We purchased these partnerships for an aggregate amount of $43.0 million, which will be drawn on our corporate credit facility during the third quarter of 2011. These purchases included the remaining working interests in a total of 146 gross, 104.5 net, wells located in our Wattenberg and Grand Valley Fields. At the time of closing the acquisitions, net production from the 2005 Partnerships was estimated to be approximately 4 MMcfe/day with estimated net reserves of 27 Bcfe, comprised of approximately 67% natural gas. The acquisitions allow us the opportunity, assuming favorable capital and commodity markets, to accelerate the pace of refracturing the wells acquired, thus allowing us to optimize revenue opportunities.

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The following table presents the adjusted purchase price and the preliminary allocation thereof, based on our estimates of fair value, for natural gas and crude oil properties acquired from our 2005 Partnerships.

	(in thousands)
Total acquisition cost	$43,015
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Assets acquired:	
Natural gas and crude oil properties - proved	$39,825
Fair value of derivative instruments, net	479
Other assets	3,369
Total assets acquired	43,673
Liabilities assumed:	
Asset retirement obligation	300
Other liabilities	358
Total liabilities assumed	658
Total identifiable net assets acquired	$43,015

Pro Forma Information. The results of operations for the above acquisition have been included in our consolidated financial statements from the date of acquisition. The pro forma effect of these acquisitions on our results of operations as if the acquisition had occurred as of January 1, 2010, have not been presented, as the pro forma results would not be materially different from the information presented in the accompanying statements of operations.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

EXECUTIVE SUMMARY

2011 Capital Budget

In July 2011, the Board approved an increase in our 2011 capital budget to $397 million. The original plan was approved in January 2011 for $233 million. The following table details the $164 million increase in our 2011 capital plan and the expenditure class to which it was allocated.

	2011 Capital Budget		
	Original	Increase	Revised
	(in millions)		
Developmental drilling	$205	$88	$293
Affiliated partnership acquisitions	—	73	73
Exploration, leasing and other	28	3	31
	$233	$164	$397

The majority of the increase in developmental drilling is expected to be further allocated to the liquid-rich Wattenberg Field, including an expansion of the horizontal Niobrara program. We now expect to drill a total of 147 vertical wells and 25 horizontal wells (16 Niobrara and nine Marcellus). Additionally, we expect to execute on 181 refrac/recompletion projects.

We believe that our new 2011 capital budget, combined with our investment in 2010, will grow production from continuing operations by 24%, from 37.6 Bcfe in 2010 to 46.5 Bcfe in 2011, while increasing the liquids portion of our production as a percentage of our total production and thereby enabling us to benefit from the crude oil to natural gas price differential. The production growth is expected to come primarily from the Wattenberg Field, including the horizontal Niobrara, Permian Basin and Marcellus Shale development as well as affiliated partnership acquisitions.

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Operational Overview and Update

For the six months ended 2011, we drilled 83 developmental wells in the Wattenberg Field, of which 43 wells were completed and turned in line. We also executed 85 refrac/recompletion projects on 46 wells in this area. Of the 83 wells drilled, six were horizontal Niobrara with four of them producing as of June 30, 2011. We drilled a total of 11 developmental wells in the Permian Basin during the six months ended 2011 with six of them producing as of the end of the period. For the six months ended June 30, 2011, PDCM spud four horizontal Marcellus wells, none of which had been turned in line as of the end of the period, and completed three horizontal Marcellus wells that were in-process as of December 31, 2010. The increases in Appalachian production of 118.1% quarter-over-quarter and 76.0% year-over-year were primarily related to the most recent horizontal completions. In June 2011, PDCM initiated its drilling program of nine horizontal Marcellus wells to be drilled in 2011, of which four were in-process as of period end. Completions are expected to begin in September and are expected to continue throughout the remainder of 2011.

Our Piceance drilling program for 2011 was expanded from 12 to 17 wells as a result of the increased 2011 capital budget. The additional five wells have been budgeted in order to obtain further reserve and production data on the Super Frac pilot program initiated in late 2010. We plan to release the drilling rig in this area following the drilling of these five wells and spend the remainder of 2011 testing the Super Frac completions. We plan to return to drilling in mid-2012.

Financial Overview

Natural gas, NGL and crude oil sales increased 48.2% quarter-over-quarter and 27.7% year-over-year. These increases were primarily driven by an increase in production of 21.3% quarter-over-quarter and 20.9% year-over-year and an increase in average price per Mcfe of 22.1% quarter-over-quarter and 5.6% year-over-year. Leading the increases in production and average price was crude oil. The increases in crude oil production of 33.2% quarter-over-quarter and 31.8% year-over-year were primarily due to our focus in our Wattenberg Field and Permian Basin during the past 12 months.

Available liquidity as of June 30, 2011, was $342.6 million, which included $13.0 million through PDCM for the development of Appalachian properties, compared to $379.3 million, which included $22.3 million through PDCM, as of December 31, 2010. The excess cash balance as of December 31, 2010, was attributable to our double tranche offering of common equity and convertible debt in November 2010. Available liquidity is comprised of cash, cash equivalents and funds available under our credit facility. It is our strong liquidity position that has afforded us the opportunity to execute, adopt and implement our increased 2011 capital spending program, which continues to stay focused on organic growth in the liquid-rich areas of our Wattenberg Field and the Permian Basin, as well as our goal to acquire affiliated partnerships.

In June 2011, we executed on our second tranche of partnership acquisitions by closing on the acquisition of the 2005 Partnerships. The aggregate purchase price of $43.0 million will be drawn on the corporate credit facility during the third quarter of 2011 and, as such, the aggregate purchase price was included in accounts payable on the accompany balance sheet as of June 30, 2011. These acquisitions included the remaining working interests in a total of 104.5 net wells and an estimated 27 Bcfe of proved reserves located in our Wattenberg and Grand Valley Fields. Additionally, with regard to the potential acquisition of the third tranche of partnerships, we filed with the SEC preliminary proxies for our 2003/2002-D Partnerships. See Note 9, Commitments and Contingencies - Merger Agreements, to the accompanying condensed consolidated financial statements included in this report.

Change in Management

As previously announced, on June 10, 2011, James M. Trimble was appointed President and Chief Executive Officer of the Company, effective immediately. Mr. Trimble began serving on the Company's Board in 2009 and now serves as Chairman of the Executive Committee and as a member on the Planning and Finance Committee. Further, concurrent with the appointment of Mr. Trimble, Richard W. McCullough resigned from his positions as Chief Executive Officer and Chairman of the Board, effective immediately, and Jeffrey C. Swoveland was appointed to the position of Non-Executive Chairman of the Board. Mr. Swoveland has served on the Board since 1991 and previously served as the Company's Presiding Independent Director. Mr. Swoveland now serves on the Audit Committee, the Planning and Finance Committee, the Compensation Committee and the Executive Committee.

Non-U.S. GAAP Financial Measures

We use "adjusted cash flow from operations," "adjusted net income (loss) attributable to shareholders" and "adjusted EBITDA," non-U.S. GAAP financial measures, for internal managerial purposes, when evaluating period-to-period comparisons and providing public guidance on possible future results. These measures are not measures of financial performance under U.S. GAAP and should be considered in addition to, not as a substitute for, net income, cash flows from operations, investing or financing activities, nor as a liquidity measure or indicator of operating results or cash flows reported in accordance with U.S. GAAP. The non-U.S. GAAP financial measures that we use may not be comparable to similarly titled measures reported by other companies. Also, in the future, we may disclose different non-U.S. GAAP financial measures in order to help our investors more meaningfully evaluate and compare our future results of operations to our previously reported results of operations. We strongly encourage investors to review our financial statements and publicly filed reports in their entirety and to not rely on any single financial measure. See Reconciliation of Non-U.S. GAAP Financial Measures below for a detailed description of these measures as well as a reconciliation of each to the nearest U.S. GAAP measure.

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Results of Operations

Summary Operating Results

The following table presents selected information regarding our operating results from continuing operations.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2011	2010	Change	2011	2010	Change
	(dollars in thousands, except per unit data)					
Production (1)						
Natural gas (MMcf)	7,513.0	6,283.4	19.6 %	15,260.3	12,796.8	19.3 %
Crude oil (MBbls)	426.8	320.6	33.1 %	798.1	605.4	31.8 %
NGLs (MBbls)	149.7	139.2	7.5 %	316.6	288.2	9.9 %
Natural gas equivalent (MMcfe) (2)	10,972.2	9,042.4	21.3 %	21,948.8	18,158.8	20.9 %
Average MMcfe per day	120.6	99.4	21.3 %	121.3	100.3	20.9 %
Natural Gas, NGL and Crude Oil Sales						
Natural gas	$26,501	$20,415	29.8 %	$50,356	$51,062	(1.4)%
Crude oil	40,330	23,244	73.5 %	72,847	44,195	64.8 %
NGLs	5,384	5,070	6.2 %	12,891	11,299	14.1 %
Total natural gas, NGL and crude oil sales	$72,215	$48,729	48.2 %	$136,094	$106,556	27.7 %
Realized Gain (Loss) on Derivatives, net (3)						
Natural gas	$6,332	$5,854	8.2 %	$13,231	$26,733	(50.5)%
Crude oil	(4,529)	2,039	*	(7,640)	4,084	(287.1)%
Total realized gain on derivatives, net	$1,803	$7,893	(77.2)%	$5,591	$30,817	(81.9)%
Average Sales Price (excluding gain/loss on derivatives)						
Natural gas (per Mcf)	$3.53	$3.25	8.6 %	$3.30	$3.99	(17.3)%
Crude oil (per Bbl)	94.50	72.49	30.4 %	91.27	73.00	25.0 %
NGLs (per Bbl)	35.94	36.43	(1.3)%	40.71	39.21	3.8 %
Natural gas equivalent (per Mcfe)	6.58	5.39	22.1 %	6.20	5.87	5.6 %
Average Sales Price (including gain/loss on derivatives)						
Natural gas (per Mcf)	$4.37	$4.18	4.5 %	$4.17	$6.08	(31.4)%
Crude oil (per Bbl)	83.88	78.84	6.4 %	81.69	79.75	2.4 %
NGLs (per Bbl)	35.94	36.43	(1.3)%	40.71	39.21	3.8 %
Natural gas equivalent (per Mcfe)	6.75	6.26	7.8 %	6.46	7.57	(14.7)%
Average Lifting Cost (per Mcfe) (4)	$1.11	$1.14	(2.6)%	$1.14	$1.05	8.6 %
Natural Gas Marketing (5)	$690	$382	80.6 %	$899	$746	20.5 %
Other Costs and Expenses						
Exploration expense	$1,720	$3,830	(55.1)%	$3,871	$10,248	(62.2)%

General and administrative expense	19,509	9,855	98.0	%	33,382	20,549	62.5	%
Depreciation, depletion and amortization	32,674	26,945	21.3	%	65,031	54,403	19.5	%
Interest Expense, net	$9,065	$7,638	18.7	%	$18,118	$15,433	17.4	%

* Percentage change is not meaningful or equal to or greater than 300%.
Amounts may not recalculate due to rounding.

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(1) Production is net and determined by multiplying the gross production volume of properties in which we have an interest by the percentage interest we own.
(2) Six Mcf of natural gas equals one Bbl of crude oil or NGL.
(3) Represents realized derivative gains and losses related to natural gas and crude oil sales segment, which do not include realized derivative gains and losses related to natural gas marketing.
(4) Represents lease operating expenses on a per unit basis.
(5) Represents sales from natural gas marketing, net of costs of natural gas marketing, including realized and unrealized derivative gains and losses related to natural gas marketing activities.

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Natural Gas, NGL and Crude Oil Sales

The following tables present natural gas, NGL and crude oil production and average sales price by area.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2011	2010	Percentage Change	2011	2010	Percentage Change
Production						
Natural gas (MMcf)						
Rocky Mountain Region	6,151.2	5,693.5	8.0 %	12,938.7	11,566.7	11.9 %
Permian Basin (1)	101.8	—	*	182.9	—	*
Appalachian Basin	1,250.2	570.8	119.0 %	2,117.1	1,201.2	76.2 %
Other	9.8	19.1	(48.7)%	21.6	28.9	(25.3)%
Total	7,513.0	6,283.4	19.6 %	15,260.3	12,796.8	19.3 %
Crude oil (MBbls)						
Rocky Mountain Region	368.4	319.5	15.3 %	688.4	603.6	14.0 %
Permian Basin (1)	56.7	—	*	106.8	—	*
Appalachian Basin	1.6	1.1	45.5 %	2.7	1.8	50.0 %
Other	0.1	—	*	0.2	—	*
Total	426.8	320.6	33.1 %	798.1	605.4	31.8 %
NGLs (MBbls)						
Rocky Mountain Region	134.4	137.1	(2.0)%	281.9	285.0	(1.1)%
Permian Basin (1)	13.4	—	*	31.5	—	*
Other	1.9	2.1	(9.5)%	3.2	3.2	— %
Total	149.7	139.2	7.5 %	316.6	288.2	9.9 %
Natural gas equivalent (MMcfe)						
Rocky Mountain Region	9,168.4	8,433.1	8.7 %	18,760.4	16,898.6	11.0 %
Permian Basin (1)	522.2	—	*	1,012.9	—	*
Appalachian Basin	1,259.8	577.5	118.1 %	2,133.5	1,212.3	76.0 %
Other	21.8	31.8	(31.4)%	42.0	47.9	(12.3)%
Total	10,972.2	9,042.4	21.3 %	21,948.8	18,158.8	20.9 %

* Percentage change is not meaningful or equal to or greater than 300%.
Amounts may not recalculate due to rounding.

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(1) Our Permian Basin properties were acquired in July and November 2010.

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Average Sales Price (excluding gain/loss on derivatives)	Three Months Ended June 30, 2011	2010	Percentage Change	Six Months Ended June 30, 2011	2010	Percentage Change
Natural gas (per Mcf) (1)						
Rocky Mountain Region	$3.31	$3.16	4.7 %	$3.11	$3.91	(20.5)%
Permian Basin (2)	2.97	—	*	3.97	—	*
Appalachian Basin	4.62	4.20	10.0 %	4.41	4.80	(8.1)%
Other	5.00	2.38	110.1 %	3.67	2.66	38.0 %
Weighted average price	3.53	3.25	8.6 %	3.30	3.99	(17.3)%
Crude oil (per Bbl)						
Rocky Mountain Region	94.39	72.49	30.2 %	92.20	72.99	26.3 %
Permian Basin (2)	95.48	—	*	85.58	—	*
Appalachian Basin	83.80	72.29	15.9 %	80.56	74.98	7.4 %
Other	101.41	—	*	93.19	—	*
Weighted average price	94.50	72.49	30.4 %	91.27	73.00	25.0 %
NGLs (per Bbl)						
Rocky Mountain Region	33.99	36.32	(6.4)%	39.28	39.02	0.7 %
Permian Basin (2)	55.17	—	*	52.46	—	*
Other	38.55	43.64	(11.7)%	51.13	56.16	(9.0)%
Weighted average price	35.94	36.43	(1.3)%	40.71	39.21	3.8 %
Natural gas equivalent (per Mcfe)						
Rocky Mountain Region	6.51	5.47	19.0 %	6.12	5.94	3.0 %
Permian Basin	12.36	—	*	11.38	—	*
Appalachian Basin	4.70	4.29	9.6 %	4.48	4.87	(8.0)%
Other	6.05	4.32	40.0 %	6.21	5.32	16.7 %
Weighted average price	6.58	5.39	22.1 %	6.20	5.87	5.6 %

* Percentage change is not meaningful or equal to or greater than 300%.
Amounts may not recalculate due to rounding.

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(1) Our average sales price for natural gas is based on the "net-back" method of accounting for transportation, gathering and processing arrangements with natural gas purchasers. See our revenue recognition policy described in Note 2, Summary of Significant Accounting Policies, to consolidated financial statements in our 2010 Form 10-K and Part 1, Item 2, Financial Condition, Liquidity and Capital Resources - Cash Flows, included in this report.

(2) Our Permian Basin properties were acquired in July and November 2010.

The quarter-over-quarter and year-over-year increases in natural gas, NGL and crude oil sales revenue were primarily due to the following:

	June 30, 2011 Three Months Ended (in millions)	Six Months Ended
Increase in production	$12.1	$25.0
Increase in average crude oil price	9.4	14.6
Increase (decrease) in average NGL price	(0.1)	0.4

Increase (decrease) in average natural gas price	2.1	(10.5)
Total increase in natural gas, NGL and crude oil sales revenue	$23.5	$29.5

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Production Costs

Production costs include our lease operating expenses, production taxes, the cost to operate wells and pipelines for our affiliated partnerships and other third parties and certain production and engineering staff related overhead costs.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in millions)			
Lease operating expenses	$12.2	$10.3	$25.0	$19.1
Production taxes	4.7	2.5	9.4	4.9
Costs of well operations and pipeline services	1.7	2.0	3.6	3.9
Overhead and other production expenses	1.1	1.2	2.7	3.1
Total production costs	$19.7	$16.0	$40.7	$31.0

Lease operating expenses. Lifting costs per Mcfe decreased 2.6% quarter-over-quarter and increased 8.6% year-over-year. The year-over-year increase was primarily due to well workovers, which include tubing and casing repairs and environmental remediation charges. Well workovers and environmental remediation charges increased $2.2 million and $0.9 million year-over-year, respectively.

Production taxes. Production taxes fluctuate with natural gas, NGL and crude oil sales. The increases in production taxes quarter-over-quarter and year-over-year were primarily related to higher ad valorem rates in new areas of production, such as the Permian Basin, as well as in existing areas of production, such as certain Colorado counties. Additionally, the increase in production taxes was also impacted by the increases in natural gas, NGL and crude oil sales for the same periods.

Commodity Price Risk Management, Net

We use various derivative instruments to manage fluctuations in natural gas and crude oil prices. We have in place a variety of floors, collars, fixed-price swaps and basis swaps on a portion of our estimated natural gas and crude oil production. We sell all of our physical natural gas and crude oil at similar prices to the indices inherent in our derivative instruments. As a result, for the volumes underlying our derivative positions, we ultimately realize a price related to our collars of no less than the floor and no more than the ceiling and, for our commodity swaps, we ultimately realize the fixed price related to our swaps.

Commodity price risk management, net, includes realized gains and losses and unrealized mark-to-market changes in the fair value of the derivative instruments related to our natural gas and crude oil production. Commodity price risk management, net, does not include derivative transactions related to our natural gas marketing, which are included in sales from and cost of natural gas marketing.

See Note 3, Fair Value Measurements and Disclosures, and Note 4, Derivative Financial Instruments, to the accompanying condensed consolidated financial statements included in this report for additional details of our derivative financial instruments. See Item 3, Quantitative and Qualitative Disclosures About Market Risk, for a detailed presentation of our open derivative positions as of June 30, 2011.

The following table presents the realized and unrealized derivative gains and losses included in commodity price risk management, net.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in millions)			
Commodity price risk management gain (loss), net:				
Realized gains (losses):				
Natural gas	$6.3	$5.9	$13.2	$26.7
Crude oil	(4.5)	2.0	(7.6)	4.1
Total realized gains, net	1.8	7.9	5.6	30.8
Unrealized gains (losses):				
Reclassification of realized gains included in prior periods unrealized	(0.8)	(7.5)	(6.6)	(21.6)
Unrealized gains (losses) for the period	19.5	11.9	(2.3)	46.3
Total unrealized gains (losses), net	18.7	4.4	(8.9)	24.7
Total commodity price risk management gain (loss), net	$20.5	$12.3	$(3.3)	$55.5

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Realized gains recognized in the three and six months ended 2011 are primarily the result of lower natural gas spot prices at settlement compared to the respective strike price of our natural gas derivative positions. For the three and six months ended 2011, realized gains on natural gas, exclusive of basis swaps, were $10.2 million and $19.3 million, respectively. These gains were offset in part by realized losses of $3.9 million and $6.1 million, respectively, on our basis swap positions as the negative basis differential between NYMEX and CIG was narrower than the strike price of the basis positions. For the three and six months ended 2011, the realized losses on our crude oil positions were due to higher spot prices at settlement compared to the respective strike price.

Unrealized gains during the three months ended 2011 were primarily related to a downward shift in the natural gas and crude oil forward curves and their impact on the fair value of our open positions. For the three months ended 2011, unrealized gains on our natural gas and crude oil positions were $7.5 million and $12.7 million, respectively, offset slightly by the narrowing of the CIG basis forward curve, which resulted in an unrealized loss of $0.7 million. For the six month period, the shift upward in the crude oil forward curve and the narrowing of the CIG basis forward curve resulted in unrealized losses of $5.8 million and $1.9 million, respectively. The shift downward in the natural gas forward curve resulted in an unrealized gain of $5.4 million.

During the three and six months ended 2010, we recorded realized gains of $7.9 million and $30.8 million as a result of lower natural gas and crude oil spot prices at settlement compared to the respective strike price, offset in part by the basis differential between NYMEX and CIG being narrower than the strike price of the derivative position. For the three months ended 2010, the unrealized gains were primarily related to our crude oil positions, as the forward strip price shifted downward during the quarter, and the widening of the NYMEX-CIG basis differential. Unrealized gains on our crude oil positions and our CIG basis swaps for the three months ended 2010 were $8.0 million and $4.0 million, respectively. For the six month period, the unrealized gains were primarily related to a downward shift in the natural gas and crude oil forward curves. For the six months ended 2010, unrealized gains on our natural gas and crude oil positions were $37.3 million and $9.2 million, respectively.

Natural Gas Marketing

Fluctuations in our natural gas marketing's income contribution are primarily due to fluctuations in natural gas prices, realized and unrealized (mark-to-market adjustments) gains and losses on derivative positions and, to a lesser extent, volumes sold and purchased.

The following table presents the components of sales from and costs of natural gas marketing.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in millions)			
Sales from natural gas marketing				
Natural gas sales revenue	$18.4	$13.3	$33.5	$31.5
Realized derivative gain	0.5	1.8	1.6	2.9
Unrealized derivative gain (loss)	—	(2.5)	(1.0)	0.9
Total sales from natural gas marketing	18.9	12.6	34.1	35.3
Costs of natural gas marketing				
Costs of natural gas purchases	17.5	12.7	32.2	30.4
Realized derivative loss	0.4	1.6	1.4	2.7
Unrealized derivative loss (gain)	0.1	(2.4)	(0.9)	0.9

Other	0.2	0.3	0.5	0.5
Total costs of natural gas marketing	18.2	12.2	33.2	34.5
Natural gas marketing contribution margin	$0.7	$0.4	$0.9	$0.8

The increases in natural gas sales revenue and costs of natural gas purchases quarter-over-quarter were primarily due to a 33.2% increase in volumes. Year-over-year, increases in natural gas sales revenue and costs of natural gas purchases were primarily due to to 21.1% increase in volume offset in part by decreases in average prices, with a 12.0% decrease in average natural gas sales price and a 15.5% decrease in average natural gas purchase price.

Derivative instruments related to natural gas marketing include both physical and cash-settled derivatives. We offer fixed-price derivative contracts for the purchase or sale of physical gas and enter into cash-settled derivative positions with counterparties in order to offset those same physical positions. See Note 4, Derivative Financial Instruments, to our 2010 Form 10-K and Item 3, Quantitative and Qualitative Disclosures About Market Risk, included in this report for a discussion of how each derivative type impacts our cash flows and detailed presentation of our derivative positions as of June 30, 2011.

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Other Costs and Expenses

Exploration Expense

The following table presents the major components of exploration expense.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in millions)			
Amortization of individually insignificant unproved properties	$0.5	$0.6	$1.0	$1.1
Exploratory dry hole costs	0.1	0.6	0.2	3.5
Geological and geophysical costs	—	0.8	0.9	1.9
Operating, personnel and other	1.1	1.8	1.8	3.7
Total exploration expense	$1.7	$3.8	$3.9	$10.2

Exploratory dry hole costs. Exploratory dry hole costs for the three and six months ended 2010 includes the fracturing and testing of several exploratory zones of a well located in the Piceance Basin as well as an oil test well drilled in the NECO area.

Geological and geophysical costs. The quarter-over-quarter and year-over-year decreases in geological and geophysical were primarily related to a reduction in geological and seismic testing. In 2010, our exploration activities in the Marcellus intensified, resulting in significant geological and seismic costs.

Operating, personnel and other. The quarter-over-quarter and year-over-year decreases in operating, personnel and other were primarily related to personnel changes as former exploration department personnel were reassigned during the first quarter of 2011 to development drilling or administrative activities.

General and Administrative Expense

General and administrative expense increased 98.0% quarter-over-quarter. The increase was primarily due to an increase in payroll and payroll related expenses of $7.3 million, of which $6.7 million and $0.5 million related to a separation agreement with our former chief executive officer and the reassignment of exploration department personnel, respectively. The year-over-year increase of 62.5% in general and administrative expense was primarily due to an increase in payroll and payroll related expense of $9.1 million, of which $6.7 million and $1.2 million related to a separation agreement with our former chief executive officer and the reassignment of exploration department personnel, respectively, as well as a $1.6 million charge to legal fees related to the settlement agreement reached with regard to our West Virginia royalty lawsuit.

Depreciation, Depletion and Amortization

Natural gas and crude oil properties. DD&A expense for natural gas and crude oil properties increased 23.0% quarter-over-quarter and 21.4% year-over-year. The increase in our production for the three and six months ended 2011 contributed $5.4 million and $10.6 million to these increases, respectively, while higher weighted average DD&A rates resulted in an increase in DD&A expense of $0.4 million for each of the three and six months ended

2011, respectively.

The following table presents our DD&A rates for natural gas and crude oil properties by area.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(per Mcfe)			
Rocky Mountain Region:				
Wattenberg Field	$3.38	$3.54	$3.32	$3.60
Grand Valley Field	2.48	2.47	2.51	2.46
Weighted average	2.88	2.77	2.85	2.78
Permian Basin	3.98	—	3.40	—
Appalachian Basin	1.97	2.71	2.20	2.67
Total weighted average	2.82	2.78	2.81	2.79

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Non-natural gas and crude oil properties. Depreciation expense for non-natural gas and crude oil properties was $1.7 million and $3.4 million for the three and six months ended 2011 compared to $1.8 million and $3.7 million for the three and six months ended 2010.

Non-Operating Income/Expense

Interest Expense. The increase in interest expense for the three and six months ended 2011 compared to the same 2010 periods is primarily related to an increase in debt issuance amortization expense, as well as a higher average outstanding debt balance. The increase in our outstanding debt balance is primarily related to our November 2010 convertible debt issuance; however, this increase was reduced in part by a reduction in outstanding borrowings under our corporate bank credit facility.

Provision/Benefit for Income Taxes

See Note 6, Income Taxes, to the accompanying condensed consolidated financial statements for a discussion of the changes in our effective tax rate quarter-over-quarter and year-over-year. Due to tax interim period benefit limitations and the different effects of permanent tax adjustments, primarily percentage depletion, the effective tax rate comparison for the three and six-month periods is less meaningful.

Beginning with our 2010 tax year, we were accepted into and have agreed to participate in the IRS Compliance Assurance Process ("CAP") program. As part of this program, we agreed to an accelerated timeline for the IRS examination of our 2007, 2008 and 2009 tax years. This examination was completed during the three months ended 2011 without any significant increase or decrease in tax expense. See Note 6, Income Taxes, to the accompanying condensed consolidated financial statements, for a discussion on the reduction of our uncertain tax liability due to the conclusion of this examination. We have accepted an offer for continued participation in the IRS CAP program for our 2011 tax year.

Discontinued Operations

See Note 12, Divestitures and Discontinued Operations, to the accompanying condensed consolidated financial statements included in this report for additional information regarding the divestiture of our North Dakota and Michigan assets.

North Dakota. In December 2010, we effected a letter of intent with an unrelated third party, which provided for the sale of 100% of our North Dakota assets. In February 2011, we executed a purchase and sale agreement and subsequently closed with the same unrelated third party. Proceeds from the sale were $9.5 million, net of non-affiliated investor partners' share of $3.8 million, resulting in a pretax gain on sale of $3.9 million. The operating results related to these assets were immaterial for the six months ended 2011 and the three and six months ended 2010.

Michigan. In July 2010, we completed the sale of our Michigan assets. Operating results related to these assets were immaterial for the three and six months ended 2010.

Net Income (Loss) Attributable to Shareholders/Adjusted Net Income (Loss) Attributable to Shareholders

Net income attributable to shareholders for the three months ended 2011 was $9.2 million compared to a net loss of $2.7 million for the three months ended 2010; net loss attributable to shareholders for the six months ended 2011 was $10.8 million compared to net income of $21.0 million for the six months ended 2010. Adjusted net loss attributable to shareholders, a non-U.S. GAAP financial measure, for the three and six months ended 2011 was $2.4 million and

$5.2 million, respectively, compared to an adjusted net loss of $5.3 million and adjusted net income of $5.6 million for the three and six months ended 2010, respectively. The changes in net income (loss) attributable to shareholders are discussed above, with the most significant changes being related to natural gas, NGL and crude oil sales, commodity price risk management activities and general and administrative expense. These same reasons for change similarly impacted adjusted net income (loss) attributable to shareholders, with the exception of the unrealized derivative gains and losses on derivatives, adjusted for taxes, as these amounts are not included in the total. See Reconciliation of Non-U.S. GAAP Financial Measures below, for a more detailed discussion of this non-U.S. GAAP financial measure.

Financial Condition, Liquidity and Capital Resources

Historically, our primary sources of liquidity have been cash flows provided by operating activities and our corporate bank credit facility. More recently, as market conditions have permitted, we have utilized the debt and equity markets and engaged in asset monetization transactions as sources of financing.

Our primary source of cash flows provided by operating activities is the sale of natural gas, NGL and crude oil. Fluctuations in our operating cash flows are substantially driven by commodity prices and changes in our production volumes. Commodity prices have historically been volatile and we manage this volatility through our derivative program. We enter into commodity derivative instruments with maturities of no greater than five years from the date of the instrument. For instruments that mature in two years or less, our debt covenants limit our holdings to 80% of our expected future production on total proved reserves (PDPs, PDNPs and PUDs). For instruments that mature greater than two years but no more than our designated maximum maturity, our debt covenants limit our holdings to 80% of our expected future production on PDPs. Therefore, we may still have significant fluctuations in our cash flows provided by operating activities due to the remaining non-hedged portion of our future production.

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Our working capital fluctuates for various reasons, including, but not limited to, changes in the fair value of our commodity derivative instruments and due to our practice of utilizing excess cash to reduce the outstanding borrowings under our credit facility. At June 30, 2011, we had a working capital deficit of $95.2 million compared to a surplus of $16.2 million at December 31, 2010. The decrease in working capital was primarily related to the increase in accounts payable, due to the 2005 Partnership acquisitions, and the decrease in cash and cash equivalents as we have executed on our 2011 capital plan.

We ended June 2011 with cash and cash equivalents of $6.8 million and availability under our credit facility of $335.8 million, for a total liquidity position of $342.6 million compared to $379.3 million at December 31, 2010. The decrease in liquidity of $36.7 million, or 9.7%, was primarily due to capital expenditures of $151.4 million, offset in part by cash flows provided by operating activities of $71.6 million, an increase in the borrowing base of our corporate credit facility of $28.8 million and $9.5 million from the divestiture of our North Dakota assets in February 2011. With our current liquidity position and expected cash flows from operations, we believe that we have sufficient capital for operations and our planned uses of capital for the next twelve-month period.

Capital Expenditures

2011 Capital Budget. We establish a capital plan each calendar year based on our development and exploration opportunities, liquidity position and the expected cash flows provided by operating activities for that year. We may revise our capital plan during the year as a result of acquisitions, drilling results, commodity prices, changes in our borrowing capacity and/or significant changes in cash flows. In January 2011, our Board approved our 2011 capital plan of $233 million, exclusive of potential acquisitions. The plan provides for $205 million in developmental drilling, including recompletions and refractures, with the remaining $28 million for exploration, leasing and other capital needs. In July 2011, our Board approved a revised 2011 capital budget. The revised budget includes a capital plan of $397 million, inclusive of our completed and anticipated affiliated partnership acquisitions, but exclusive of any potential additional acquisitions. We believe, based on the current commodity price environment and our revised estimated 2011 production of 46.5 Bcfe, an increase of approximately 24% over 2010 production from continuing operations, that our cash flows provided by operating activities will fund a significant portion of our 2011 capital plan, with the balance being financed through the use of our corporate credit facility. During the six months ended 2011, we accelerated our capital spending program due to the significant rise in crude oil prices and, as a result, completed 85 refractures/recompletions, compared to an original budget of 63, on 46 wells in the Wattenberg Field. By taking advantage of the current pricing environment, we believe that we will be able to maximize profits while minimizing the payback period.

Because production from our existing properties declines rapidly in the first few years of production, in order to grow our production, we need to continue to commit significant amounts of capital year after year. If capital is not available or is constrained in the future, we will be limited to our cash flows provided by operating activities and liquidity under our credit facility as the sources for funding our capital expenditures. We would not be able to maintain our current level of production and cash flows provided by operating activities if capital markets and commodity prices were to become depressed and/or the borrowing base on our credit facility was reduced. The occurrence of such an event may result in our immediate election to defer a substantial portion of our planned capital expenditures for any given future period and could have a material negative impact on our operations in the future.

Partnership Acquisition Plan. We are the managing general partner of various public limited partnerships. In 2010, we disclosed our intent to pursue, beginning in the fall of 2010 and extending through the next three years, the acquisition of the limited partnership units (the “Acquisition Plan”) held by investor partners of the particular partnership other than those held by PDC or its affiliates (“non-affiliated investor partners”), in certain limited partnerships that PDC had previously sponsored. For additional information regarding our intent to pursue the acquisitions of these partnerships, refer to our prior disclosure included in filings made with the SEC. However, such information shall not, by reason of this reference, be deemed to be incorporated by reference in, or otherwise be deemed to be part of, this report. Under the Acquisition Plan, any existing or future merger offer will be subject to the terms and conditions of the related merger agreement, and such agreement does or will likely contemplate the partnership being merged with and into a wholly-owned subsidiary of PDC. Each such merger will also be subject to, among other things, us having sufficient available capital, the economics of the merger and the approval by a majority of the limited partnerships units held by the non-affiliated investor partners of each respective limited partnership. Consummation of any proposed merger of a limited partnership under the Acquisition Plan will result in the termination of the existence of that partnership and the right of non-affiliated investor partners to receive a cash payment for their limited partnership units in that partnership.

We expect that the acquisition of these partnerships will provide us with immediate growth in both production and proved reserves from assets with which we are familiar. We believe that these acquisitions will also allow us to realize operational benefits and cost synergies as well as the opportunity to identify, pursue and accelerate a refracture program of the wells acquired. See Notes 9 and 15, Commitments and Contingencies – Merger Agreements and Acquisition, respectively, to the accompanying condensed consolidated financial statements included in this report for a discussion of the pending acquisition of the 2003/2002-D Partnerships and the completed acquisition of our 2005 Partnerships. We expect to finance any future partnership acquisitions through the utilization of our corporate bank credit facility.

Financing Activities

We have to date experienced no impediments in our ability to access borrowings under our current corporate bank credit facility or the capital markets, as demonstrated by our November 2010 capital market transactions. We cannot guarantee however, that such access will continue in the future. We continue to monitor market events and circumstances and their potential impacts on each of the lenders that comprise our corporate bank credit facility. Our corporate bank credit facility borrowing base is subject to size redeterminations each May and November based upon a quantification of our proved reserves at each December 31st and June 30th, respectively. A commodity price deck reflective of the current and future commodity pricing environment is utilized by our lenders to quantify our reserve reports and determine the underlying borrowing base. On May 6, 2011, based on our May redetermination, our borrowing base was increased to $350 million from $321.2 million. Our next scheduled redetermination will be effective for November 2011. While we continually aim to add producing reserves through our drilling operations, we believe a significant decrease in commodity prices could have a negative impact on our future borrowing base redeterminations.

We have a shelf registration statement on Form S-3 filed with the SEC in November 2008 and declared effective by the SEC in January 2009. The shelf provides for an aggregate of $500 million, through the potential sale of debt securities, common stock or preferred stock, either separately or represented by depository shares, warrants and purchase contracts, as well as units that may include any of these securities or securities of other entities. The shelf registration statement is intended to allow us to be proactive in our ability to raise capital should the need arise, and to have the flexibility to raise such funds in one or more offerings should we perceive the market conditions to be favorable. As of June 30, 2011, we have $315.8 million available on our shelf, which we may utilize to raise future capital.

We are subject to quarterly financial debt covenants on our corporate bank credit facility. Currently, our key credit facility debt covenants require that we maintain: 1) total debt of less than 4.25 times earnings before interest, taxes, DD&A expense and exploration expense adjusted for certain non-cash transactions ("EBITDAX") and 2) an adjusted working capital ratio of at least 1.0 to 1.0. Our adjusted working capital ratio is calculated by reducing our current assets and liabilities by any impact of recording the fair value of our natural gas and crude oil derivative instruments and adding our available borrowings on our corporate bank credit facility to our current assets. The impact of any current portion of our debt is eliminated from the current liabilities, therefore any change in our available borrowings under our credit facility impacts our working capital ratio. We were in compliance with all debt covenants at June 30, 2011, and expect to remain in compliance throughout the next twelve-month period.

The indenture governing our senior notes contains customary representations and warranties as well as typical restrictive covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to: (a) incur additional debt, (b) make certain investments or pay dividends or distributions on our capital stock or purchase or redeem or retire capital stock, (c) sell assets, including capital stock of our restricted subsidiaries, (d) pay dividends or other payments by restricted subsidiaries, (e) create liens that secure debt, (f) enter into transactions with affiliates and (g) merge or consolidate with another company. Additionally, with regard to our 12% senior notes, we are subject to two incurrence covenants: 1) EBITDAX of at least two times interest expense and 2) total debt of less than 4.0 times EBITDAX. We were in compliance with all covenants at June 30, 2011, and expect to remain in compliance throughout the next twelve-month period.

See Part I, Item 3, Quantitative and Qualitative Disclosures about Market Risk, for our discussion of credit risk.

Cash Flows

Operating Activities. Our cash flows provided by operating activities are primarily impacted by commodity prices, production volumes, realized gains and losses from our derivative positions, operating costs and general and administrative expenses. Cash flows provided by operating activities decreased year-over-year. The decrease was primarily due to the income tax refund of $25.9 million from our 2009 NOL carry-back received during the six months ended 2010. See Results of Operations above for an additional discussion of the key drivers of cash flows provided by operating activities.

Natural gas, NGL and crude oil prices exhibit a high degree of volatility. These price variations have a material impact on our financial results. Natural gas and NGL prices vary by region and locality, depending upon the distance to markets, the availability of pipeline capacity and the supply and demand relationships in that region or locality. This can be especially true in the Rocky Mountain Region. The combination of increased drilling activity and the lack of local markets has resulted in local market oversupply situations from time to time. Like most producers in the region, we rely on major interstate pipeline companies to construct these pipelines to increase capacity, rendering the timing and availability of these facilities beyond our control. Crude oil pricing is predominately driven by the physical market, supply and demand, the financial markets and global unrest.

The price we receive for our natural gas produced in the Rocky Mountain Region is based on a market basket of prices, which generally includes natural gas sold at, near or below CIG prices as well as other nearby region prices. The CIG Index and other indices for production delivered to other Rocky Mountain pipelines have historically been less than the price received for natural gas produced in the eastern regions, which is NYMEX-based. This negative differential has narrowed over the last few years and is lower than historical variances. The negative differential of CIG relative to NYMEX averaged $0.31 and $0.32 for the six months ended 2011 and 2010, respectively.

The price we receive on our natural gas is impacted by our transportation, gathering and processing agreements. We currently use the "net-back" method of accounting for these arrangements related to our natural gas sales. We sell natural gas at the wellhead and collect a price and recognize revenues based on the wellhead sales price since transportation costs downstream of the wellhead are incurred by the purchaser and reflected in the wellhead price. The net-back method results in the recognition of a sales price that is below the indices for which the production is based.

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Adjusted cash flows from operations decreased year-over-year. The decrease was primarily due to the same factors mentioned above for changes in cash provided by operating activities without regard to timing of cash payments and receipts of our assets and liabilities. See Reconciliation of Non-U.S. GAAP Financial Measures, below, for a more detailed discussion of these non-U.S. GAAP financial measures.

Investing Activities. Net cash used in investing activities was primarily related to the acquisition, exploration and development of natural gas and crude oil properties, net of dispositions of natural gas and crude oil properties. Our capital investment in natural gas and crude oil properties has increased significantly year-over-year as a result of our commitment to growth.

Financing Activities. During the six months ended 2010, financing activities were a use of cash compared to being a source of cash during the six months ended 2011 as we continue to execute our 2011 capital plan. Additionally, for the six months ended 2011, financing cash flows include $6.4 million, representing our proportionate share of capital contributed to PDCM by our investing partner.

Drilling Activity

The following tables present our developmental and exploratory drilling activity. There is no correlation between the number of productive wells completed during any period and the aggregate reserves attributable to those wells. Productive wells consist of wells spudded, turned in line and producing during the period. In-process wells represent wells that have been spudded, drilled and are waiting to be completed and/or for gas pipeline connection during the period.

	Gross Drilling Activity							
	Three Months Ended June 30,				Six Months Ended June 30,			
	2011		2010		2011		2010	
	Productive	In-Process	Productive	In-Process	Productive	In-Process (1)	Productive	In-Process
Development Wells								
Rocky Mountain Region	4	43	24	29	45	50	61	35
Permian Basin	1	4	—	—	6	5	—	—
Appalachian Basin	—	4	—	—	—	4	—	—
Total development wells	5	51	24	29	51	59	61	35
Exploratory Wells								
Rocky Mountain Region	—	—	—	—	—	1	—	—
Appalachian Basin	—	—	—	3	—	—	1	3
Total exploratory wells	—	—	—	3	—	1	1	3
Total drilling activity	5	51	24	32	51	60	62	38
Recompletions/refractures	15		5		46		16	

(1) As of June 30, 2011, a total of 61 wells, including the 59 development wells drilled during the six months ended 2011 and still in-process as of June 30, were waiting to be completed and/or for pipeline connection.

	Net Drilling Activity							
	Three Months Ended June 30,				Six Months Ended June 30,			
	2011		2010		2011		2010	
	Productive	In-Process	Productive	In-Process	Productive	In-Process	Productive	In-Process

Development Wells								
Rocky Mountain Region	3.8	30.7	19.6	22.9	33.1	35.9	53.6	27.0
Permian Basin	1.0	4.0	—	—	6.0	5.0	—	—
Appalachian Basin	—	2.1	—	—	—	2.1	—	—
Total development wells	4.8	36.8	19.6	22.9	39.1	43.0	53.6	27.0
Exploratory Wells								
Rocky Mountain Region	—	—	—	—	—	1.0	—	—
Appalachian Basin	—	—	—	1.7	—	—	0.6	1.8
Total exploratory wells	—	—	—	1.7	—	1.0	0.6	1.8
Total drilling activity	4.8	36.8	19.6	24.6	39.1	44.0	54.2	28.8
Recompletions/refractures	14.3		4.2		43.2		14.7	

Off-Balance Sheet Arrangements

As of June 30, 2011, with the exception of those identified under Contractual Obligations and Contingent Commitments - Commitments, contingencies and other arrangements below, we had no existing off-balance sheet arrangements, as defined under SEC rules, that have or are reasonably likely to have a material current or future effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Commitments and Contingencies

See Note 9, Commitments and Contingencies, to the accompanying condensed consolidated financial statements included in this report.

Contractual Obligations and Contingent Commitments

The table below presents our contractual obligations and contingent commitments as of June 30, 2011.

	Payments due by period				
		Less than	1-3	3-5	More than
Contractual Obligations and Contingent Commitments	Total	1 year	years	years	5 years
	(in millions)				
Long-term liabilities reflected on the consolidated balance sheets (1)					
Long-term debt (2)	$334.4	$—	$—	$16.4	$318.0
Derivative contracts (3)	54.5	22.3	31.8	0.4	—
Derivative contracts - affiliated partnerships (4)	13.2	5.9	7.3	—	—
Production tax liability	29.8	18.5	11.3	—	—
Asset retirement obligations	28.7	0.2	0.4	0.8	27.3
Other liabilities (5)	10.1	0.3	3.8	0.6	5.4
	470.7	47.2	54.6	18.2	350.7
Commitments, contingencies and other arrangements (6)					
Interest on long-term debt (7)	189.6	30.8	60.8	58.4	39.6
Operating leases	9.0	2.2	3.5	2.3	1.0
Rig commitment (8)	4.5	3.4	1.1	—	—
Drilling commitment	0.9	—	—	—	0.9
Firm transportation and processing agreements (9)	168.4	19.9	46.8	36.4	65.3
Other	0.5	0.1	0.3	0.1	—
	372.9	56.4	112.5	97.2	106.8
Total	$843.6	$103.6	$167.1	$115.4	$457.5

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(1) Table does not include deferred income tax liability to taxing authorities of $179.7 million, due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations.

(2) Amount presented does not agree with the balance sheet in that the amount above excludes $20.3 million in unamortized debt discount. See Note 7, Long-Term Debt, to the accompanying condensed consolidated financial statements included in this report.

(3) Represents our gross liability related to the fair value of derivative positions, including the fair value of derivative contracts we entered into on behalf of our affiliated partnerships as the managing general partner. We have a related receivable from the partnerships of $9.5 million.

(4) Represents our affiliated partnerships' designated portion of the fair value of our gross derivative assets.

(5) Includes funds held from revenue distribution to third party investors for plugging liabilities related to wells we operate and deferred officer compensation.

(6) Table does not include an undrawn $18.7 million irrevocable standby letter of credit pending issuance to a transportation service provider; see Note 7, Long-Term Debt, in the accompanying condensed consolidated financial statements included in this report. Additionally, the table does not include the annual repurchase obligations to investing partners of our affiliated partnerships or termination benefits related to employment agreements with our executive officers, due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations; see Note 9, Commitments and Contingencies - Partnership Repurchase Provision; Employment Agreements with Executive Officers, to the accompanying condensed consolidated financial statements included in this report.

(7) Amounts presented include $18.2 million payable to the holders of our 3.25% convertible senior notes due 2016 and $161.4 million to the holders of our 12% senior notes due 2018. Amounts also include $9.0 million payable to the participating banks of our revolving credit facility, of which interest of $7.0 million due on the unutilized commitment at a rate of 0.5% per annum, $1.6 million related to the outstanding balance of $8.5 million on our corporate credit facility and $0.4 million related to the undrawn $18.7 million letter of credit at a rate of 2.2% per annum.

(8) Drilling rig commitment in the above table reflects our proportionate share of the maximum obligation for the services of one drilling rig in the Appalachian Basin.

(9) Represents our gross commitment, including our proportionate share of PDCM. We will recognize in our financial statements our proportionate share based on our working interest; however, the costs of all volume shortfalls will be borne by PDC only. See Note 9, Commitments and Contingencies - Firm Transportation Agreements, to the accompanying condensed consolidated financial statements included in this report.

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As the managing general partner of 26 partnerships, we have liability for potential casualty losses in excess of the partnership assets and insurance. We believe that the casualty insurance coverage we and our subcontractors carry is adequate to meet this potential liability.

For information regarding our legal proceedings and their potential impact on our condensed consolidated financial statements, see Note 9, Commitments and Contingencies – Litigation, to the accompanying condensed consolidated financial statements included in this report.

Recent Accounting Standards

See Note 2, Recent Accounting Standards, to the accompanying condensed consolidated financial statements included in this report.

Critical Accounting Policies and Estimates

The preparation of the accompanying condensed financial statements in conformity with U.S. GAAP requires management to use judgment in making estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities and the reported amounts of revenue and expenses.

There have been no significant changes to our critical accounting policies and estimates or in the underlying accounting assumptions and estimates used in these critical accounting policies from those disclosed in the consolidated financial statements and accompanying notes contained in our 2010 Form 10-K.

Reconciliation of Non-U.S. GAAP Financial Measures

Adjusted cash flows from operations. We define adjusted cash flows from operations as the cash flow earned or incurred from operating activities without regard to the collection or payment of associated receivables or payables. We believe it is important to consider adjusted cash flows from operations as well as cash flows from operations, as we believe it often provides more transparency into what drives the changes in our operating trends, such as production, prices, operating costs, and related operational factors, without regard to whether the earned or incurred item was collected or paid during the period. We also use this measure because the collection of our receivables or payment of our obligations has not been a significant issue for our business, but merely a timing issue from one period to the next, with fluctuations generally caused by significant changes in commodity prices. See the condensed consolidated statements of cash flows in this report.

Adjusted net income (loss) attributable to shareholders. We define adjusted net income (loss) attributable to shareholders as net income (loss) attributable to shareholders plus unrealized derivative losses, provisions for underpayment of natural gas sales, minus unrealized derivative gains, each adjusted for tax effect. We believe it is important to consider adjusted net income (loss) attributable to shareholders as well as net income (loss) attributable to shareholders. We believe it often provides more transparency into our operating trends, such as production, prices, operating costs, realized gains and losses from derivatives and related factors, without regard to changes in our net income (loss) attributable to shareholders from our mark-to-market adjustments resulting from unrealized gains and losses from derivatives.

Adjusted EBITDA. We define adjusted EBITDA as net income (loss) plus unrealized derivative loss, interest expense, net of interest income, provision for income taxes, and depreciation, depletion and amortization for the period minus unrealized derivative gain and benefit for income taxes. We believe adjusted EBITDA is relevant because it is a measure of cash available to fund our capital expenditures and service our debt and is a widely used industry metric which allows comparability of our results with our peers.

The following table presents a reconciliation of each of our non-U.S. GAAP financial measures to its nearest U.S. GAAP measure.

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(in millions)			
Adjusted cash flows from operations:				
Adjusted cash flows from operations	$34.1	$28.8	$60.2	$78.2
Changes in assets and liabilities	22.0	15.2	11.4	17.2
Net cash provided by operating activities	$56.1	$44.0	$71.6	$95.4
Adjusted net income (loss) attributable to shareholders:				
Adjusted net income (loss) attributable to shareholders	$(2.4)	$(5.3)	$(5.2)	$5.6
Unrealized gain (loss) on derivatives, net	18.7	4.2	(9.1)	24.7
Tax effect of above adjustments	(7.1)	(1.6)	3.5	(9.3)
Net income (loss) attributable to shareholders	$9.2	$(2.7)	$(10.8)	$21.0
Adjusted EBITDA:				
Adjusted EBITDA	$35.7	$26.5	$72.5	$80.1
Unrealized gain (loss) on derivatives, net	18.7	4.2	(9.1)	24.7
Interest expense, net	(9.1)	(7.6)	(18.1)	(15.4)
Income tax benefit (expense)	(3.4)	1.7	8.9	(12.5)
Depreciation, depletion and amortization	(32.7)	(27.5)	(65.0)	(55.9)
Net income (loss) attributable to shareholders	$9.2	$(2.7)	$(10.8)	$21.0

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market-Sensitive Instruments and Risk Management

We are exposed to market risks associated with interest rates, commodity prices and credit exposure. Management has established risk management processes to monitor and manage these market risks.

Interest Rate Risk

Changes in interest rates affect the amount of interest we earn on our cash, cash equivalents and restricted cash and the interest we pay on bank credit facilities. All of our other long-term indebtedness have a fixed rate and, therefore, near-term changes in interest rates do not expose us to risk of earnings or cash flow loss; however, near-term changes in interest rates may affect the fair value of our fixed-rate debt.

As of June 30, 2011, our interest-bearing deposit accounts included money market accounts, certificates of deposit and checking and savings accounts with various banks. The amount of our interest-bearing cash and cash equivalents as of June 30, 2011, was $5.0 million with an average interest rate of 0.4%. The $5.0 million represents our aggregate bank balances, which includes checks issued and outstanding. Based on a sensitivity analysis of our interest bearing deposits as of June 30, 2011, it was estimated that if market interest rates were to increase or decrease by 1%, the impact on our 2011 interest income would be immaterial.

As of June 30, 2011, excluding the pending $18.7 million irrevocable standby letter of credit, we had outstanding borrowings on our corporate bank credit facility of $8.5 million and, representing our proportionate share, $7.9 million on PDCM's bank credit facility. It is estimated that if market interest rates were to increase or decrease by 1%, the impact on our 2011 interest income would be immaterial.

Commodity Price Risk

We are exposed to commodity price risk, the potential risk of loss from adverse changes in the market price of natural gas and crude oil commodities. We employ established policies and procedures to manage a portion of the risks associated with these market fluctuations using derivative instruments. These instruments allow us to predict with greater certainty the effective natural gas and crude oil prices to be received for our hedged production as it is produced. We believe that our established derivative policies and procedures are effective in achieving our risk management objectives for which they were intended.

Derivative Strategies. Our derivative strategies with regard to natural gas and crude oil sales and natural gas marketing are discussed below.

- For natural gas and crude oil sales, we enter into derivative contracts to protect against price declines in future periods. While we structure these derivatives to reduce our exposure to changes in price associated with the derivative commodity, they also

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limit the benefit we might otherwise have received from price increases in the physical market.

- For natural gas marketing, we enter into fixed-price physical purchase and sale agreements that qualify as derivative contracts. In order to offset the fixed-price physical derivatives in our natural gas marketing, we enter into financial derivative instruments that have the effect of locking in the prices we will receive or pay for the same volumes and period, offsetting the physical derivative.

The following table presents the derivative positions related to our natural gas and crude oil sales in effect as of June 30, 2011.

	Floors		Collars			Fixed-Price Swaps		CIG Basis Protection Swaps		
Commodity/ Index/ Maturity Period	Quantity (Oil - MBbls)	Weighted Average Contract Price	Quantity (Gas - BBtu (1) Oil - MBbls)	Weighted Average Contract Price Floors	Weighted Average Contract Price Ceilings	Quantity (Gas - BBtu (1) Oil - MBbls)	Weighted Average Contract Price	Quantity (BBtu) (1)	Weighted Average Contract Price	Fair Value June 30, 2011 (2) (in thousands)
Natural Gas NYMEX										
2011	—	$ —	—	$—	$—	6,720.2	$ 6.71	5,394.4	$ (1.82)	$7,227
2012	—	—	4,885.7	6.00	8.27	7,906.6	6.58	9,861.2	(1.81)	6,674
2013	—	—	4,438.0	6.10	8.60	6,204.8	6.82	8,903.2	(1.81)	3,872
2014	—	—	—	—	—	758.4	5.49	—	—	50
CIG										
2011	—	—	—	—	—	2,661.8	4.41	—	—	578
2012	—	—	—	—	—	700.0	4.11	—	—	(243)
2013	—	—	235.0	4.00	5.45	—	—	—	—	(26)
2014	—	—	1,115.0	4.50	5.67	—	—	—	—	(23)
2015	—	—	1,040.0	4.50	5.67	—	—	—	—	(230)
PEPL										
2011	—	—	—	—	—	1,773.8	5.60	—	—	2,309
2012	—	—	—	—	—	1,355.8	6.18	—	—	2,138
2013	—	—	—	—	—	990.4	6.18	—	—	1,309
Total Natural Gas	—		11,713.7			29,071.8		24,158.8		23,635
Crude Oil NYMEX										
2011	113.0	78.41	172.4	79.85	104.78	373.0	82.64	—	—	(5,877)
2012	36.0	65.38	643.6	81.41	106.28	444.0	91.27	—	—	(6,222)
2013	—	—	317.6	75.00	104.30	186.9	84.15	—	—	(5,388)
2014	—	—	36.0	90.00	106.15	—	—	—	—	(81)
2015	—	—	36.0	90.00	106.15	—	—	—	—	(76)
Total Crude Oil	149.0		1,205.6			1,003.9		—		(17,644)
Total Natural Gas and Crude										$5,991

Oil

(1) A standard unit of measurement for natural gas (one BBtu equals one MMcf).

(2) Approximately 20.6% of the fair value of our derivative assets and 12.4% of our derivative liabilities were measured using significant unobservable inputs (Level 3); see Note 3, Fair Value Measurements and Disclosures, to the accompanying condensed consolidated financial statements.

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The following table presents our derivative positions related to our natural gas marketing in effect as of June 30, 2011.

Commodity/ Derivative Instrument/ Maturity Period	Fixed-Price Swaps Quantity (BBtu)(1)	Fixed-Price Swaps Weighted Average Contract Price	NYMEX Basis Protection Swaps Quantity (BBtu)(1)	NYMEX Basis Protection Swaps Weighted Average Contract Price	Fair Value June 30, 2011 (2) (in thousands)
Natural Gas					
Sales					
Physical					
2011	4.7	$5.66	31.1	$0.94	$25
2012	1.4	5.85	55.1	0.95	36
Financial					
2011	938.8	5.24	128.8	0.07	714
2012	871.6	4.87	227.6	0.07	49
2013	90.0	5.00	—	—	(23)
Purchases					
Physical					
2011	938.2	5.23	—	—	(586)
2012	870.4	4.85	—	—	43
2013	90.0	4.99	—	—	26
Financial					
2011	4.0	4.55	12.6	0.13	(1)
2012	1.4	4.87	30.4	0.13	(2)
Total Natural Gas	3,810.5		485.6		$281

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(1) A standard unit of measurement for natural gas (one BBtu equals one MMcf).

(2) Approximately 5.8% of the fair value of our derivative assets were measured using significant unobservable inputs (Level 3); see Note 3, Fair Value Measurements and Disclosures, to the accompanying condensed consolidated financial statements.

The following table presents monthly average NYMEX and CIG closing prices for natural gas and crude oil for the periods identified, as well as average sales prices we realized for the respective commodities.

	Six Months Ended June 30, 2011	Year Ended December 31, 2010
Average Index Closing Price		
Natural Gas (per MMBtu)		
CIG	$3.90	$3.92
NYMEX	4.21	4.39
Crude Oil (per Bbl)		
NYMEX	97.15	77.32

Average Sales Price Realized		
Excluding realized derivative gains/(losses)		
Natural Gas (per Mcf)	$3.30	$3.61
Crude Oil (per Bbl)	91.27	74.03
Including realized derivative gains/(losses)		
Natural Gas (per Mcf)	4.17	5.12
Crude Oil (per Bbl)	81.69	79.62

Based on a sensitivity analysis as of June 30, 2011, it was estimated that a 10% increase in natural gas and crude oil prices, inclusive of basis, over the entire period for which we have derivatives in place, including those designated to our affiliated partnerships, would result in a decrease in the fair value of our derivative positions of $37.8 million; whereas a 10% decrease in prices would result in an increase in fair value of $37.7 million. Excluding the derivatives designated to our affiliated partnerships, the same 10% increase or decrease in natural gas and crude oil prices would result in a decrease in fair value of $34.7 million and an increase in fair value of $34.6 million, respectively.

See Note 3, Fair Value Measurements and Disclosures, and Note 4, Derivative Financial Instruments, to the accompanying condensed consolidated financial statements included in this report for additional disclosure regarding our derivative financial instruments including, but not limited to, a summary of our open derivative positions as of June 30, 2011.

Credit Risk

Credit risk represents the loss that we would incur if a counterparty fails to perform under its contractual obligations. We attempt to reduce credit risk by diversifying our counterparty exposure and entering into transactions with high-quality counterparties. When exposed to credit risk, we analyze the counterparties' financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of those limits on an ongoing basis.

With regard to our natural gas and crude oil sales segment, inherent to our industry is the concentration of natural gas, NGL and crude oil sales to a few customers. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic and financial conditions, commodity prices or other conditions. As for our natural gas marketing segment, our receivables are from a diverse group of companies, including major energy companies, both upstream and mid-stream, financial institutions and end-users in various industries. We monitor their creditworthiness through credit reports and rating agency reports. To date, we have had no material counterparty default losses in either of our natural gas and crude oil sales segment or natural gas marketing segment.

Our derivative financial instruments expose us to the credit risk of nonperformance by the counterparty to the contracts. We primarily use financial institutions, which are also major lenders in our credit facility, as counterparties to our derivative contracts. We have evaluated the credit risk of the counterparties holding our derivative assets using relevant credit market default rates, giving consideration to amounts outstanding from each counterparty and the duration of each outstanding derivative position. Based on our evaluation, we have determined that the impact of the nonperformance of our counterparties on the fair value of our derivative instruments is insignificant.

Disruption in the credit market may have a significant adverse impact on a number of financial institutions. We monitor the creditworthiness of the financial institutions with which we transact, giving consideration to the reports of credit agencies and their related ratings. While we believe that our monitoring procedures are sufficient and customary, no amount of analysis can guarantee performance by a financial institution.

Disclosure of Limitations

Because the information above included only those exposures that exist as of June 30, 2011, it does not consider those exposures or positions which could arise after that date. As a result, our ultimate realized gain or loss with respect to interest rate and commodity price fluctuations will depend on the exposures that arise during the period, our commodity price risk management strategies at the time, and interest rates and commodity prices at the time.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of June 30, 2011, we carried out an evaluation under the supervision and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rules 13a-15(e) and 15d-15(e). This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the SEC reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms, and that such information is accumulated and communicated to our management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely discussion regarding required disclosure.

Based on the results of this evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2011.

Changes in Internal Control over Financial Reporting

During the three months ended 2011, we made no changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act) that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

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PART II

ITEM 1. LEGAL PROCEEDINGS

Information regarding our legal proceedings can be found in Note 9, Commitments and Contingencies – Litigation, to the accompanying condensed consolidated financial statements included in this report.

ITEM 1A. RISK FACTORS

We face many risks. Factors that could materially adversely affect our business, financial condition, operating results or liquidity and the trading price of our common stock are described under Item 1A, Risk Factors, of our 2010 Form 10-K. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC. There have been no material changes from the risk factors previously disclosed in our 2010 Form 10-K.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
April 1 - 30, 2011	13,265	$40.19	—	—
May 1 - 31, 2011	13,496	39.76	—	—
June 1 - 30, 2011	—	—	—	—
Total	26,761	39.98		

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(1) Purchases represent shares purchased from employees for the payment of their tax liabilities related to the vesting of securities issued pursuant to our stock-based compensation plans.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES - None

ITEM 4. [REMOVED AND RESERVED]

ITEM 5. OTHER INFORMATION - None

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ITEM 6. EXHIBITS

With the exception of the following additions, there have been no material changes in the exhibits index previously disclosed in our 2010 Form 10-K and subsequent quarterly filings on Form 10-Q.

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
10.1 *	Separation Agreement and General Release by and between Richard W. McCullough and Petroleum Development Corporation, effective as of July 14, 2011.	8-K	000-07246	10.1	7/18/2011	
10.2 †	First Amendment to the Gas Purchase Agreement between Williams Production RMT Company LLC, Riley Natural Gas Company and Petroleum Development Corporation, executed July 27, 2011, dated and effective as of June 1, 2011.	8-K	000-07246	10.1	8/2/2011	
12.1	Computation of Ratio of Earnings to Fixed Charges.					X
31.1	Certification by Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2	Certification by Chief Financial Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
32.1	Certifications by Chief Executive Officer and Chief Financial Officer pursuant to Title 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of Sarbanes-Oxley Act of 2002.					X

*Management contract or compensatory plan or arrangement.
† Confidential portions of this document have been omitted and will be filed separately with the SEC pursuant to Rule 24b-2 under the Exchange Act.

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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, thereunto duly authorized.

Petroleum Development Corporation
(Registrant)

Date: August 4, 2011

/s/ James M. Trimble
James M. Trimble,
President and Chief Executive Officer
(principal executive officer)

/s/ Gysle R. Shellum
Gysle R. Shellum
Chief Financial Officer
(principal financial officer)

/s/ R. Scott Meyers
R. Scott Meyers
Chief Accounting Officer
(principal accounting officer)