Approach Resources Inc
Form 10-Q
November 07, 2011

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

(Mark One)

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 2011

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: 001-33801

APPROACH RESOURCES INC.

(Exact name of registrant as specified in its charter)

Delaware	**51-0424817**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
One Ridgmar Centre **6500 West Freeway, Suite 800** **Fort Worth, Texas**	**76116**
(Address of principal executive offices)	(Zip Code)

(817) 989-9000

(Registrant s telephone number, including area code)

N/A

(Former name, former address and former fiscal year, if changed since last report)

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. þ Yes o No

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

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 þ	Non-accelerated filer o (Do not check if smaller reporting company)	Smaller reporting company o

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

The number of shares of the registrant s common stock, $0.01 par value, outstanding as of October 31, 2011, was 28,441,142.

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PART I FINANCIAL INFORMATION

Item 1. Financial Statements.

Approach Resources Inc. and Subsidiaries
Unaudited Consolidated Balance Sheets
(In thousands, except shares and per-share amounts)

	September 30, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 736	$ 23,465
Accounts receivable:		
Joint interest owners	241	8,319
Oil, NGL and gas sales	9,995	6,044
Unrealized gain on commodity derivatives	2,802	862
Prepaid expenses and other current assets	273	322
Deferred income taxes current	1,307	2,318
Total current assets	15,354	41,330
PROPERTIES AND EQUIPMENT:		
Oil and gas properties, at cost, using the successful efforts method of accounting	687,452	474,917
Furniture, fixtures and equipment	1,601	1,077

		689,053		475,994
Less accumulated depletion, depreciation and amortization		(128,986)		(106,784)
Net properties and equipment		560,067		369,210
OTHER ASSETS		1,103		2,549
Total assets	$	576,524	$	413,089
LIABILITIES AND STOCKHOLDERS EQUITY				
CURRENT LIABILITIES:				
Advances from non-operators	$		$	509
Accounts payable		22,696		11,426
Oil, NGL and gas sales payable		3,844		5,534
Accrued liabilities		15,834		10,686
Unrealized loss on commodity derivatives				1,085
Total current liabilities		42,374		29,240
NON-CURRENT LIABILITIES:				
Long-term debt		122,000		
Unrealized loss on commodity derivatives		75		871
Deferred income taxes		52,727		44,616
Asset retirement obligations		6,509		5,416
Total liabilities		223,685		80,143
COMMITMENTS AND CONTINGENCIES				
STOCKHOLDERS EQUITY :				
Preferred stock, $0.01 par value, 10,000,000 shares authorized none outstanding				
Common stock, $0.01 par value, 90,000,000 shares authorized, 28,439,109 and 28,226,890 issued and outstanding, respectively		284		282
Additional paid-in capital		277,303		273,912
Retained earnings		75,512		58,986
Accumulated other comprehensive loss		(260)		(234)
Total stockholders equity		352,839		332,946
Total liabilities and stockholders equity	$	576,524	$	413,089

See accompanying notes to these consolidated financial statements.

Approach Resources Inc. and Subsidiaries
Unaudited Consolidated Statements of Operations
(In thousands, except shares and per-share amounts)

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
REVENUES:				
Oil, NGL and gas sales	$ 27,958	$ 14,916	$ 77,264	$ 41,291
EXPENSES:				
Lease operating	3,564	1,995	9,820	6,038
Severance and production taxes	1,419	743	4,223	2,047
Exploration	1,969	568	6,877	2,245
General and administrative	3,785	3,212	11,878	7,902
Depletion, depreciation and amortization	8,355	5,832	22,394	16,677
Total expenses	19,092	12,350	55,192	34,909
OPERATING INCOME	8,866	2,566	22,072	6,382
OTHER:				
Interest expense, net	(1,016)	(615)	(2,391)	(1,631)
Realized gain on commodity derivatives	1,392	1,615	1,654	3,613
Unrealized gain (loss) on commodity derivatives	1,739	(312)	3,821	2,882
Gain on sale of oil and gas properties			491	
INCOME BEFORE INCOME TAX PROVISION	10,981	3,254	25,647	11,246
INCOME TAX PROVISION	3,908	1,167	9,121	4,045
NET INCOME	$ 7,073	$ 2,087	$ 16,526	$ 7,201
EARNINGS PER SHARE:				
Basic	$ 0.25	$ 0.10	$ 0.58	$ 0.34
Diluted	$ 0.25	$ 0.10	$ 0.58	$ 0.34
WEIGHTED AVERAGE SHARES OUTSTANDING:				
Basic	28,440,909	21,357,682	28,398,152	21,139,089
Diluted	28,652,211	21,484,465	28,628,074	21,265,794

See accompanying notes to these consolidated financial statements.

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Approach Resources Inc. and Subsidiaries
Unaudited Consolidated Statements of Comprehensive Income
(In thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	**2010**	**2011**	**2010**
Net income	$ 7,073	$ 2,087	$ 16,526	$ 7,201
Other comprehensive income (loss):				
Foreign currency translation, net of related income tax	(24)	(3)	(26)	(3)
Total comprehensive income	$ 7,049	$ 2,084	$ 16,500	$ 7,198

See accompanying notes to these consolidated financial statements.

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Approach Resources Inc. and Subsidiaries
Unaudited Consolidated Statements of Cash Flows
(In thousands)

	Nine Months Ended September 30, 2011	2010
OPERATING ACTIVITIES:		
Net income	$ 16,526	$ 7,201
Adjustments to reconcile net income to cash provided by operating activities:		
Depletion, depreciation and amortization	22,394	16,677
Unrealized gain on commodity derivatives	(3,821)	(2,882)
Gain on sale of oil and gas properties	(491)	
Exploration expense	6,877	2,245
Share-based compensation expense	3,637	2,043
Deferred income taxes	9,121	3,974
Changes in operating assets and liabilities:		
Accounts receivable	6,171	(5,053)
Prepaid expenses and other assets	327	477
Accounts payable	10,011	4,182
Oil, NGL and gas sales payable	(1,690)	2,298
Accrued liabilities	5,152	1,293
Cash provided by operating activities	74,214	32,455
INVESTING ACTIVITIES:		
Additions to oil and gas properties	(218,385)	(52,385)
Proceeds from gain on sale of oil and gas properties, net	363	
Additions to other property and equipment, net	(524)	(730)
Cash used in investing activities	(218,546)	(53,115)
FINANCING ACTIVITIES:		
Proceeds from issuance of common stock upon exercise of stock options	505	
Borrowings under credit facility	169,200	81,400
Repayment of amounts outstanding under credit facility	(47,200)	(62,650)
Loan origination fees	(875)	(354)
Cash provided by financing activities	121,630	18,396
CHANGE IN CASH AND CASH EQUIVALENTS	(22,702)	(2,264)
EFFECT OF FOREIGN CURRENCY TRANSLATION ON CASH AND CASH EQUIVALENTS	(27)	(4)
CASH AND CASH EQUIVALENTS, beginning of period	$ 23,465	$ 2,685

CASH AND CASH EQUIVALENTS, end of period	$ 736	$ 417
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:		
Cash paid for interest	$ 2,340	$ 1,524

See accompanying notes to these consolidated financial statements.

Approach Resources Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Unaudited)
September 30, 2011

1. Summary of Significant Accounting Policies

Organization and Nature of Operations

Approach Resources Inc. (Approach, the Company, we, us or our) is an independent energy company engage the exploration, development, production and acquisition of oil and gas properties. We focus on finding and developing oil and natural gas reserves in oil shale and tight sands. Our properties are primarily located in the Permian Basin in West Texas. We also own interests in the East Texas Basin and the Chama Basin in Northern New Mexico.

During the nine months ended September 30, 2011, we sold our working interest in Northeast British Columbia for net proceeds of $363,000. The gain on the sale of this interest was $491,000, and is included under Other on the consolidated statement of operations for the nine months ended September 30, 2011. Our carrying value and associated plugging obligations related to Northeast British Columbia previously were written off as an impairment of unproved properties during the year ended December 31, 2009.

Consolidation, Basis of Presentation and Significant Estimates

The interim consolidated financial statements of the Company are unaudited and contain all adjustments (consisting primarily of normal recurring accruals) necessary for a fair statement of the results for the interim periods presented. Results for interim periods are not necessarily indicative of results to be expected for a full year due in part to the volatility in prices for crude oil and natural gas, future commodity prices for commodity derivative contracts, global economic and financial market conditions, interest rates, access to sources of liquidity, estimates of reserves, drilling risks, geological risks, transportation restrictions, the timing of acquisitions, product supply and demand, market competition and interruptions of production. You should read these consolidated interim financial statements in conjunction with the audited consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2010, filed with the Securities and Exchange Commission on March 11, 2011.

The accompanying interim consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America and include the accounts of the Company and its wholly-owned subsidiaries. Intercompany accounts and transactions are eliminated. In preparing the accompanying financial statements, we have made certain estimates and assumptions that affect reported amounts in the financial statements and disclosures of contingencies. Actual results may differ from those estimates. Significant assumptions are required in the valuation of proved oil and natural gas reserves, which affect the amount at which oil and natural gas properties are recorded. Significant assumptions are also required in estimating our accrual of capital expenditures, asset retirement obligations and share-based compensation. It is at least reasonably possible these estimates could be revised in the near term, and these revisions could be material. Certain prior year amounts have been reclassified to conform to current year presentation. These classifications have no impact on the net income reported.

Approach Resources Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Unaudited)
September 30, 2011

2. Working Interest Acquisition

In February 2011, we acquired an additional 38% working interest in our Cinco Terry operating area from two non-operating partners for $76 million, subject to customary post-closing adjustments (the Working Interest Acquisition). We funded the Working Interest Acquisition with cash on hand and borrowings under our revolving credit facility.

The following table summarizes the preliminary purchase price paid and its allocation at September 30, 2011 (in thousands).

Purchase price:	
Acquisition price	$ 76,000
Asset retirement obligations assumed	547
Post-closing purchase price adjustments	(6,366)
Total	$ 70,181
Allocation:	
Wells, equipment and related facilities	$ 50,979
Mineral interests in oil and gas properties	19,202
Total	$ 70,181

3. Earnings Per Common Share

We report basic earnings per common share, which excludes the effect of potentially dilutive securities, and diluted earnings per common share, which includes the effect of all potentially dilutive securities unless their impact is antidilutive. The following table provides a reconciliation of the numerators and denominators of our basic and diluted earnings per share (dollars in thousands, except per-share amounts).

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Income (numerator):				
Net income basic	$ 7,073	$ 2,087	$ 16,526	$ 7,201
Weighted average shares (denominator):				
Weighted average shares basic	28,440,909	21,357,682	28,398,152	21,139,089
Dilution effect of share-based compensation, treasury method	211,302	126,783	229,922	126,705
Weighted average shares diluted	28,652,211	21,484,465	28,628,074	21,265,794
Net income per share:				
Basic	$ 0.25	$ 0.10	$ 0.58	$ 0.34
Diluted	$ 0.25	$ 0.10	$ 0.58	$ 0.34

4. Revolving Credit Facility

At September 30, 2011, we had a $300 million revolving credit facility with a borrowing base set at $200 million. The borrowing base is redetermined semi-annually on or before each April 1 and October 1 based on our oil, NGL and gas reserves. We or the lenders can each request one additional borrowing base redetermination each calendar year.

Approach Resources Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Unaudited)
September 30, 2011

The maturity date under our revolving credit facility is July 31, 2014. Borrowings bear interest based on the agent bank s prime rate plus an applicable margin ranging from 0.75% to 1.75%, or the sum of the Eurodollar rate plus an applicable margin ranging from 1.75% to 2.75%. Margins vary based on the borrowings outstanding compared to the borrowing base. In addition, we pay an annual commitment of 0.50% of unused borrowings available under our revolving credit facility.

Effective October 7, 2011, we entered into an eleventh amendment to our credit agreement, which, among other things, (i) increased the borrowing base to $260 million from $200 million, and (ii) added Wells Fargo Bank, N.A. as a sixth lender to the bank syndicate.

We had outstanding borrowings of $122 million under our revolving credit facility at September 30, 2011. We had no outstanding borrowings at December 31, 2010. The interest rate applicable to our revolving credit facility at September 30, 2011, was 2.8%. We also had outstanding unused letters of credit under our revolving credit facility totaling $350,000 at September 30, 2011, which reduce amounts available for borrowing under our revolving credit facility.

Loans under our revolving credit facility are secured by first priority liens on substantially all of our West Texas assets and are guaranteed by our subsidiaries.

Covenants

Our credit agreement contains two principal financial covenants:

a consolidated modified current ratio covenant that requires us to maintain a ratio of not less than 1.0 to 1.0 at all times. The consolidated modified current ratio is calculated by dividing Consolidated Current Assets (as defined in the credit agreement) by Consolidated Current Liabilities (as defined in the credit agreement). As defined more specifically in the credit agreement, the consolidated modified current ratio is calculated as current assets less current unrealized gains on commodity derivatives plus the available borrowing base at the respective balance sheet date, divided by current liabilities less current unrealized losses on commodity derivatives at the respective balance sheet date.

a consolidated funded debt to consolidated EBITDAX ratio covenant that requires us to maintain a ratio of not more than 4.0 to 1.0 at the end of each fiscal quarter. The consolidated funded debt to consolidated EBITDAX ratio is calculated by dividing Consolidated Funded Debt (as defined in the credit agreement) by Consolidated EBITDAX (as defined in the credit agreement). As defined more specifically in the credit agreement, consolidated EBITDAX is calculated as net income (loss), plus (1) exploration expense, (2) depletion, depreciation and amortization expense, (3) share-based compensation expense, (4) unrealized loss on commodity derivatives, (5) interest expense, (6) income and franchise taxes and (7) certain other noncash expenses, less (x) gains or losses from sales or dispositions of assets, (y) unrealized gain on commodity derivatives and (z) extraordinary or nonrecurring gains. For purposes of calculating this ratio, consolidated EBITDAX for a fiscal quarter is annualized pursuant to the credit agreement.

Our credit agreement also restricts cash dividends and other restricted payments, transactions with affiliates, incurrence of other debt, consolidations and mergers, the level of operating leases, assets sales, investments in other entities and liens on properties.

Approach Resources Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Unaudited)
September 30, 2011

In addition, our credit agreement contains customary events of default that would permit our lenders to accelerate the debt under our credit agreement if not cured within applicable grace periods, including, among others, failure to make payments of principal or interest when due, materially incorrect representations and warranties, failure to make mandatory prepayments in the event of borrowing base deficiencies, breach of covenants, defaults upon other obligations in excess of $500,000, events of bankruptcy, the occurrence of one or more unstayed judgments in excess of $500,000 not covered by an acceptable policy of insurance, failure to pay any obligation in excess of $500,000 owed under any derivatives transaction or in any amount if the obligation under the derivatives transaction is secured by collateral under the credit agreement, any event of default by the Company occurs under any agreement entered into in connection with a derivatives transaction, liens securing the loans under the credit agreement cease to be in place, a Change in Control (as defined in the credit agreement) of the Company occurs, and dissolution of the Company.

At September 30, 2011, we were in compliance with all of our covenants and had not committed any acts of default under the credit agreement.

5. Commitments and Contingencies

In August 2011, we settled all claims with EnCana Oil & Gas (USA) Inc. (EnCana) arising out of *Approach Operating, LLC v. EnCana Oil & Gas (USA) Inc., Cause No. 29.070A*, District Court of Limestone County, Texas. As previously disclosed, on July 2, 2009, our operating subsidiary filed a lawsuit against EnCana for breach of the joint operating agreement (JOA) covering our North Bald Prairie project in East Texas and seeking damages for nonpayment of amounts owed under the JOA as well as declaratory relief. As part of the release and settlement of all claims by both parties, EnCana paid us $1.4 million. In addition, we will remain operator of the North Bald Prairie project, subject to the terms of the JOA.

We are involved in various legal and regulatory proceedings arising in the normal course of business. While we cannot predict the outcome of these proceedings with certainty, we do not believe that an adverse result in any pending legal or regulatory proceeding, individually or in the aggregate, would be material to our consolidated financial condition or cash flows; however, an unfavorable outcome could have a material adverse effect on our results of operations for a specific interim period or year.

We have entered into an 18-month contract for a dedicated, third-party fracture stimulation fleet, effective September 1, 2011. The contract requires a minimum commitment of $3 million per month for the contract term. The contract contains customary, early termination provisions for a monthly fee of less than the minimum monthly commitment in the event of a termination before the end of the contract term.

6. Income Taxes

The effective income tax rate for the three and nine months ended September 30, 2011, was 35.6%. Total income tax expense for the three and nine months ended September 30, 2011, differed from amounts computed by applying the U.S. federal statutory tax rates to pre-tax income due primarily to state taxes and the impact of permanent differences between book and taxable income.

The effective income tax rate for the three and nine months ended September 30, 2010, was 35.9% and 36.0%, respectively. Total income tax expense for the three and nine months ended September 30, 2010, differed from amounts computed by applying the U.S. federal statutory tax rates to pre-tax income due to the impact of permanent differences between book and taxable income.

Approach Resources Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Unaudited)
September 30, 2011

7. Derivatives

The following table sets forth our commodity derivative volumes and prices for 2011 and 2012.

Period	Contract Type	Volume Transacted	Contract Price
Natural Gas			
2011	Swap	230,000 MMBtu/month	$ 4.86
June 2011 December 2011	Swap	200,000 MMBtu/month	$ 4.74
2012	Call	230,000 MMBtu/month	$ 6.00
Natural Gas Basis Differential			
2011	Swap	300,000 MMBtu/month	$ (0.53)
Crude Oil			
May 2011 December 2011	Collar	1,000 Bbls/day	$ 100.00 - $127.00

In October 2011, we added to its 2012 commodity derivatives positions with a crude oil collar contract covering 700 Bbls/d at a contract price of $85.00/Bbl $97.50/Bbl.

The following table summarizes the fair value of our open commodity derivatives as of September 30, 2011, and December 31, 2010 (in thousands).

	Asset Derivatives			Liability Derivatives		
		Fair Value			Fair Value	
	Balance Sheet Location	September 30, 2011	December 31, 2010	Balance Sheet Location	September 30, 2011	December 31, 2010
Derivatives not designated as hedging instruments						
Commodity derivatives	Unrealized gain on commodity derivatives	$ 2,802	$ 862	Unrealized loss on commodity derivatives	$ 75	$ 1,956

The following table summarizes the change in the fair value of our commodity derivatives (in thousands).

	Income Statement Location	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Derivatives not designated as hedging instruments					
Commodity derivatives		$ 1,392	$ 1,615	$ 1,654	$ 3,613

Realized gain on commodity derivatives				
Unrealized gain (loss) on commodity derivatives	1,739	(312)	3,821	2,882
	$ 3,131	$ 1,303	$ 5,475	$ 6,495

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Approach Resources Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Unaudited)
September 30, 2011

Unrealized gains and losses, at fair value, are included on our consolidated balance sheets as current or non-current assets or liabilities based on the anticipated timing of cash settlements under the related contracts. Changes in the fair value of our commodity derivative contracts are recorded in earnings as they occur and included in other income (expense) on our consolidated statements of operations. We estimate the fair values of swap contracts based on the present value of the difference in exchange-quoted forward price curves and contractual settlement prices multiplied by notional quantities. We internally valued the option contracts using industry-standard option pricing models and observable market inputs. We use our internal valuations to determine the fair values of the contracts that are reflected on our consolidated balance sheets. Realized gains and losses are also included in other income (expense) on our consolidated statements of operations.

We are exposed to credit losses in the event of nonperformance by the counterparties on our commodity derivatives positions and have considered the exposure in our internal valuations. However, we do not anticipate nonperformance by the counterparties over the term of the commodity derivatives positions.

To estimate the fair value of our commodity derivatives positions, we use market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the market approach for recurring fair value measurements and attempt to use the best available information. We determine the fair value based upon the hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and lowest priority to unobservable inputs (Level 3 measurement). The three levels of fair value hierarchy are as follows:

Level 1 Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. At September 30, 2011, we had no Level 1 measurements.

Level 2 Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Our derivatives, which consist primarily of commodity swaps and collars, are valued using commodity market data which is derived by combining raw inputs and quantitative models and processes to generate forward curves. Where observable inputs are available, directly or indirectly, for substantially the full term of the asset or liability, the instrument is categorized in Level 2. At September 30, 2011, all of our commodity derivatives were valued using Level 2 measurements.

Level 3 Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management s best estimate of fair value. At September 30, 2011, our Level 3 measurements were limited to our asset retirement obligation.

Approach Resources Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Unaudited)
September 30, 2011

8. Share-Based Compensation

During the nine months ended September 30, 2011, we made a grant of 204,000 restricted shares of common stock to our executive officers. The total fair market value of these shares on the grant date was approximately $6.5 million, which will be expensed over a service period of approximately four years, subject to certain performance measures. We recognized $1.8 million in share-based compensation expense related to this grant during the nine months ended September 30, 2011.

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations.

The following discussion is intended to assist in understanding our results of operations and our financial condition. This section should be read in conjunction with management s discussion and analysis contained in our Annual Report on Form 10-K for the year ended December 31, 2010, filed with the Securities and Exchange Commission (SEC) on March 11, 2011. Our consolidated financial statements and the accompanying notes included elsewhere in this Quarterly Report on Form 10-Q contain additional information that should be referred to when reviewing this material. Certain statements in this discussion may be forward-looking. These forward-looking statements involve risks and uncertainties, which could cause actual results to differ from those expressed in this report. A glossary containing the meaning of the oil and gas industry terms used in this management s discussion and analysis follows the Results of Operations table in this Item 2.

Cautionary Statement Regarding Forward-Looking Statements

Various statements in this report, including those that express a belief, expectation or intention, as well as those that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act). The forward-looking statements may include projections and estimates concerning the timing and success of specific projects, typical well economics and our future reserves, production, revenues, costs, income, capital spending, 3-D seismic operations, interpretation and results and obtaining permits and regulatory approvals. When used in this report, the words will, believe, intend, expect, may, should, anticipate, could, estim predict, project, potential or their negatives, other similar expressions or the statements that include those words, are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

These forward-looking statements are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management s assumptions about future events may prove to be inaccurate. We caution all readers that the forward-looking statements contained in this report are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to the factors listed or referred to in the Risk Factors section and elsewhere in this report. All forward-looking statements speak only as of the date of this report. We expressly disclaim all responsibility to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us, or persons acting on our behalf. The risks, contingencies and uncertainties relate to, among other matters, the following:

- our business strategy, including our ability to recover oil and gas in place associated with our Wolffork oil resource play in the Permian Basin;
- estimated quantities of oil, NGL and gas reserves;
- uncertainty of commodity prices in oil, gas and NGLs;
- overall United States and global economic and financial market conditions;
- domestic and foreign demand and supply for oil, gas, NGLs and the products derived from such hydrocarbons;
- disruption of credit and capital markets;

our financial position;
our cash flow and liquidity;
replacing our oil and gas reserves;
our inability to retain and attract key personnel;
uncertainty regarding our future operating results;
uncertainties in exploring for and producing oil and gas;
high costs, shortages, delivery delays or unavailability of drilling and completion, equipment, materials, labor or other services;
disruptions to, capacity constraints in or other limitations on the pipeline systems that deliver our gas and NGLs and other processing and transportation considerations, including limited availability of oil hauling trucks in the Permian Basin, our primary area of operation;
our inability to obtain additional financing necessary to fund our operations and capital expenditures and to meet our other obligations;
competition in the oil and gas industry;
marketing of oil, gas and NGLs;
interpretation of 3-D seismic data;
development of our current asset base or property acquisitions;
the effects of government regulation and permitting and other legal requirements;
plans, objectives, expectations and intentions contained in this report that are not historical; and
other factors discussed in our Annual Report on Form 10-K for the year ended December 31, 2010, filed with the SEC on March 11, 2011, and in this Quarterly Report on Form 10-Q for the three months ended September 30, 2011.

Overview

Approach Resources Inc. (Approach, the Company, we, us or our) is an independent energy company engage the exploration, development, production and acquisition of oil and gas properties. We focus on oil and natural gas reserves in oil shale and tight sands. Our management and technical team has a proven track record of finding and developing reservoirs through advanced completion, fracturing and drilling techniques. Our core properties are primarily located in the Permian Basin in West Texas (Clearfork, Wolfcamp Shale, Canyon Sands, Strawn and Ellenburger). We also own interests in the East Texas Basin (Cotton Valley Sands and Cotton Valley Lime) and in the Chama Basin in Northern New Mexico (Mancos Shale). As the operator of all of our estimated proved reserves and production, we have a high degree of control over capital expenditures and other operating matters.

At June 30, 2011, we had estimated proved oil and gas reserves of 66.8 MMBoe. Our reserve base is 55% oil and NGLs, 45% natural gas and 50% proved developed. Over 97% of our proved reserves and production are located in the Permian Basin in Crockett and Schleicher Counties, Texas. Our acreage position in the Permian Basin totals approximately 142,000 net, primarily contiguous acres and is characterized by multiple oil and liquids-rich formations. Our 2011 drilling program includes operating three rigs to target the Wolffork, the Wolfcamp Shale and the Canyon Sands and deeper zones. We refer to our drilling program in the Permian Basin as Project Pangea and Pangea West.

Third Quarter of 2011 Activity

During the third quarter of 2011, we drilled a total of 20 gross (20 net) wells, completed 14 gross (14 net) wells and recompleted four gross (four net) wells. Through September 30, 2011, we drilled 52 gross (47.3 net) wells, completed 49 gross (42.7 net) wells and recompleted six gross (six net) wells. At September 30, 2011, we had 10 wells waiting on completion. We currently have one horizontal rig and two vertical rigs running in Project Pangea. At September 30, 2011, we owned working interests in approximately 613 producing oil and gas wells.

Results of Operations

The following table sets forth summary information regarding oil, NGL and gas revenues, production, average product prices and average production costs and expenses for the three and nine months ended September 30, 2011 and 2010. We determined the barrel of oil equivalent using the ratio of six Mcf of natural gas to one barrel of oil equivalent, and one barrel of NGLs to one barrel of oil equivalent.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	**2010**	**2011**	**2010**
Revenues (in thousands)				
Oil	$ 9,568	$ 5,135	$ 27,792	$ 12,630
NGLs	12,128	2,565	29,416	6,899
Gas	6,262	7,216	20,056	21,762
Total oil, NGL and gas sales	27,958	14,916	77,264	41,291
Realized gain on commodity derivatives	1,392	1,615	1,654	3,613
Total oil, NGL and gas sales including derivative impact	$ 29,350	$ 16,531	$ 78,918	$ 44,904
Production				
Oil (MBbls)	117	71	310	172
NGLs (MBbls)	233	70	574	174
Gas (MMcf)	1,569	1,664	4,829	4,646
Total (MBoe)	612	418	1,689	1,120
Total (MBoe/d)	6.7	4.5	6.2	4.1
Average prices				
Oil (per Bbl)	$ 81.51	$ 72.19	$ 89.63	$ 73.41
NGLs (per Bbl)	52.08	36.65	51.26	39.64
Gas (per Mcf)	3.99	4.34	4.15	4.68
Total (per Boe)	$ 45.70	$ 35.68	$ 45.75	$ 36.87
Realized gain on commodity derivatives (per Boe)	2.28	3.86	0.98	3.22
Total including derivative impact (per Boe)	$ 47.98	$ 39.54	$ 46.73	$ 40.09
Costs and expenses (per Boe)				
Lease operating (1)	$ 5.82	$ 4.77	$ 5.81	$ 5.39
Severance and production taxes	2.32	1.78	2.50	1.83
Exploration	3.22	1.36	4.07	2.00
General and administrative	6.18	7.68	7.03	7.06
Depletion, depreciation and amortization	13.65	13.95	13.26	14.89

(1) Lease operating expense per Boe includes ad valorem taxes.

Glossary

Bbl. One stock tank barrel, of 42 U.S. gallons liquid volume, used herein to reference oil, condensate or NGLs.
Boe. Barrel of oil equivalent, determined using the ratio of six Mcf of gas to one Bbl of oil equivalent, and one Bbl of NGLs to on Bbl of oil equivalent.
MBbl. Thousand barrels of oil, condensate or NGLs.
MBoe. Thousand barrels of oil equivalent, determined using the ratio of six Mcf of gas to one Bbl of oil equivalent, and one Bbl of NGLs to one Bbl of oil equivalent.

Mcf. Thousand cubic feet of natural gas.
MMBoe. Million barrels of oil equivalent, determined using the ratio of six Mcf of gas to one Bbl of oil equivalent, and one Bbl of NGLs to one Bbl of oil equivalent.
MMcf. Million cubic feet of natural gas.
NGLs. Natural gas liquids.
/d. Per day when used with volumetric units or dollars.

Three Months Ended September 30, 2011, Compared to Three Months Ended September 30, 2010

Oil, NGL and gas sales. Oil, NGL and gas sales increased $13.1 million, or 87%, for the three months ended September 30, 2011, to $28 million, from $14.9 million for the three months ended September 30, 2010. Of the $13.1 million increase in oil, NGL and gas sales, approximately $11.9 million was attributable to an increase in oil and NGL production volumes and $1.2 million was attributable to an increase in oil and NGL prices. Subject to commodity prices, we expect our 2011 oil, NGL and gas sales to continue to increase over 2010 prior periods due to increased production volumes from our drilling program in the Permian Basin, the acquisition of additional working interest in northwest Project Pangea in first quarter 2011 (the Working Interest Acquisition) and realization of NGL revenues in Ozona Northeast resulting from a gas purchase and processing contract that provides for the sale of NGLs from the gas stream in the southeast portion of Project Pangea.

Our average realized prices for the three months ended September 30, 2011, before the effect of commodity derivatives, were $81.51 per Bbl of oil, $52.08 per Bbl of NGLs and $3.99 per Mcf of natural gas, compared to $72.19 per Bbl of oil, $36.65 per Bbl of NGLs and $4.34 per Mcf of natural gas, for the three months ended September 30, 2010. Our average realized price, including the effect of commodity derivatives, was $47.98 per Boe for the three months ended September 30, 2011, compared to $39.54 per Boe for the three months ended September 30, 2010. The regional index prices that we use to price our oil, NGL and gas sales sometimes reflect a discount to the relevant benchmark prices, such as New York Mercantile Exchange (NYMEX) and West Texas Intermediate (WTI). The difference between the benchmark price and the price we reference in our sales contacts is called a differential. We currently expect our 2011 oil price differential to increase over 2010 prior periods due to increased activity levels in the Permian Basin and a shortage of oil haulers in the region.

Oil, NGL and gas production. Production for the three months ended September 30, 2011, totaled 612 MBoe (6.7 MBoe/d), compared to 418 MBoe (4.5 MBoe/d) produced in the prior year period, an increase of 46%. Production for the three months ended September 30, 2011, was 57% oil and NGLs and 43% natural gas, compared to 34% oil and NGLs and 66% natural gas in the prior year period. The increase in production in the 2011 period is the result of our continued development of our Permian Basin properties, the Working Interest Acquisition and processing NGLs in the southeast portion of Project Pangea; however, production was impacted during the three months ended September 30, 2011, by oil takeaway constraints due to increased industry activity in the Permian Basin and a shortage of oil trucking capacity. We expect 2011 production to continue to increase over 2010 prior periods due to the Working Interest Acquisition, our expected drilling program in the Permian Basin and the processing of NGLs from the gas stream in the southeast portion of Project Pangea.

Commodity derivative activities. Our commodity derivative activity resulted in a realized gain of $1.4 million and $1.6 million for the three months ended September 30, 2011, and 2010, respectively. Realized gains and losses on commodity derivatives are derived from the relative movement of commodity prices in relation to the fixed notional pricing in our price collars, options and swaps for the applicable periods. The unrealized gain on commodity derivatives was $1.7 million for the three months ended September 30, 2011, compared to an unrealized loss of $312,000 for the three months ended September 30, 2010. As commodity prices increase, the fair value of the open portion of those positions decreases. As commodity prices decrease, the fair value of the open portion of those positions increases. Historically, we have not designated our derivative instruments as cash-flow hedges. We record our open derivative instruments at fair value on our consolidated balance sheets as either unrealized gains or losses on commodity derivatives. We record changes in such fair value in net income on our consolidated statements of operations under the caption entitled unrealized gain (loss) on commodity derivatives.

Lease operating expenses. Our lease operating expenses (LOE) increased $1.6 million, or 79%, for the three months ended September 30, 2011, to $3.6 million ($5.82 per Boe) from $2 million ($4.77 per Boe) for the three months ended September 30, 2010. The increase in LOE for the three months ended September 30, 2011, was primarily attributable to the Working Interest Acquisition. In February 2011, we acquired the remaining 38% working interest in northern Project Pangea, which increased our working interest to approximately 100%. We also experienced an increase in water hauling, insurance and repair and maintenance expenses as well as generally higher service costs. For the remainder of 2011, we expect LOE to continue to be higher compared to the prior year period.

The following table summarizes LOE (per Boe).

	Three Months Ended September 30,			
	2011	**2010**	**Change**	**% Change**
Compression and gas treating	$ 1.33	$ 1.42	$ (0.09)	(6.3)%
Water hauling, insurance and other	1.32	1.07	0.25	23.4
Well repairs and maintenance	1.15	0.41	0.74	180.5
Ad valorem taxes	1.13	1.05	0.08	7.6
Pumping and supervision	0.89	0.82	0.07	8.5
Total	$ 5.82	$ 4.77	$ 1.05	22.0%

Severance and production taxes. Our severance and production taxes increased $676,000, or 91%, for the three months ended September 30, 2011, to $1.4 million from $743,000 for the three months ended September 30, 2010. The increase in severance and production taxes was primarily the result of an increase in oil, NGL and gas sales between the two periods. Severance and production taxes were approximately 5.1% and 5.0% of oil, NGL and gas sales for the respective periods. For the remainder of 2011, we expect severance and production taxes as a percent of oil, NGL and gas sales will remain relatively consistent compared to the severance and production taxes for the nine months ended September 30, 2011.

Exploration. We recorded $2 million ($3.22 per Boe) and $568,000 ($1.36 per Boe) of exploration expense for the three months ended September 30, 2011 and 2010, respectively. Exploration expense for the three months ended September 30, 2011 and 2010, includes costs related to 3-D seismic data in Pangea West and Project Pangea.

General and administrative. Our general and administrative expenses (G&A) increased $573,000, or 18%, to $3.8 million ($6.18 per Boe) for the three months ended September 30, 2011, from $3.2 million ($7.68 per Boe) for the three months ended September 30, 2010. The increase in G&A was principally due to salaries and benefits. The decrease in G&A per Boe was primarily attributable to an increase in production during the three months ended September 30, 2011, compared to the three months ended September 30, 2010. For 2011, we expect G&A to be higher, compared to 2010, as a result of higher share-based compensation and staffing increases during 2010.

The following table summarizes G&A (in millions and per Boe).

	Three Months Ended September 30,						
	2011		2010		Change		
	$MM	Boe	$MM	Boe	$MM	Boe	% Change
Salaries and benefits	$ 1.6	$ 2.59	$ 1.1	$ 2.57	$ 0.5	$ 0.02	0.8%
Share-based compensation	1.1	1.78	1.1	2.74		(0.96)	(35.0)
Professional fees	0.2	0.39	0.4	1.05	(0.2)	(0.66)	(62.9)
Other	0.9	1.42	0.6	1.32	0.3	0.10	7.6
Total	$ 3.8	$ 6.18	$ 3.2	$ 7.68	$ 0.6	$ (1.50)	(19.5)%

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expense (DD&A) increased $2.6 million, or 43%, to $8.4 million for the three months ended September 30, 2011, from $5.8 million for the three months ended September 30, 2010. The increase in DD&A expense over the prior year period was primarily due to an increase in capital expenditures in the three months ended September 30, 2011. Our DD&A per Boe decreased by $0.30, or 2%, to $13.65 per Boe for the three months ended September 30, 2011, compared to $13.95 per Boe for the three months ended September 30, 2010. The decrease in DD&A per Boe was primarily attributable to an increase in estimated proved developed reserves, partially offset by an increase in production and capitalized costs over the prior year period.

Interest expense, net. Our interest expense, net, increased $401,000, or 65%, to $1 million for the three months ended September 30, 2011, from $615,000 for the three months ended September 30, 2010. This increase was the result of a higher average debt level in the 2011 period. For the remainder of 2011, we expect interest expense to continue to be higher compared to the prior year period.

Income taxes. Our income taxes increased $2.7 million to $3.9 million for the three months ended September 30, 2011, from $1.2 million for the three months ended September 30, 2010. The increase in income taxes was due to higher net income in the 2011 period. Our effective income tax rate for the three months ended September 30, 2011, was 35.6%, compared with 35.9% for the three months ended September 30, 2010.

Nine Months Ended September 30, 2011, Compared to Nine Months Ended September 30, 2010

Oil, NGL and gas sales. Oil, NGL and gas sales increased $36 million, or 87%, for the nine months ended September 30, 2011, to $77.3 million, from $41.3 million for the nine months ended September 30, 2010. Of the $36 million increase in oil, NGL and gas sales, approximately $33.7 million was attributable to an increase in production volumes and $2.3 million was attributable to an increase in oil and NGL prices. Subject to commodity prices, we expect our 2011 oil, NGL and gas sales to continue to increase over 2010 prior periods due to increased production volumes from our drilling program in the Permian Basin, the Working Interest Acquisition and realization of NGL revenues in Ozona Northeast resulting from a gas purchase and processing contract that provides for the sale of NGLs from the gas stream in the southeast portion of Project Pangea.

Our average realized prices for the nine months ended September 30, 2011, before the effect of commodity derivatives, were $89.63 per Bbl of oil, $51.26 per Bbl of NGLs and $4.15 per Mcf of natural gas, compared to $73.41 per Bbl of oil, $39.64 per Bbl of NGLs and $4.68 per Mcf of natural gas, for the nine months ended September 30, 2010. Our average realized price, including the effect of commodity derivatives, was $46.73 per Boe for the nine months ended September 30, 2011, compared to $40.09 per Boe for the nine months ended September 30, 2010. The regional index prices that we use to price our oil, NGL and gas sales sometimes reflect a discount to the relevant benchmark prices, such as NYMEX and WTI. The difference between the benchmark price and the price we reference in our sales contacts is called a differential. We currently expect our 2011 oil price differential to increase over 2010 prior periods due to increased activity levels in the Permian Basin and a shortage of oil haulers in the region.

Oil, NGL and gas production. Production for the nine months ended September 30, 2011, totaled 1,689 MBoe (6.2 MBoe/d), compared to 1,120 MBoe (4.1 MBoe/d) produced in the prior year period, an increase of 51%. Production for the nine months ended September 30, 2011, was 52% oil and NGLs and 48% natural gas, compared to 31% oil and NGLs and 69% natural gas in the prior year period. The increase in production in the 2011 period is the result of our continued development of our Permian Basin properties, the Working Interest Acquisition and processing NGLs in the southeast portion of Project Pangea; however, production was impacted during the nine months ended September 30, 2011, by oil takeaway constraints due to increased industry activity in the Permian Basin and a shortage of oil trucking capacity. We expect production to continue to increase during 2011 over 2010 prior periods due to the Working Interest Acquisition, our expected drilling program in the Permian Basin and the processing of NGLs from the gas stream in the southeast portion of Project Pangea.

Commodity derivative activities. Our commodity derivative activity resulted in a realized gain of $1.7 million and $3.6 million for the nine months ended September 30, 2011, and 2010, respectively. Realized gains and losses on commodity derivatives are derived from the relative movement of commodity prices in relation to the fixed notional pricing in our price collars, options and swaps for the applicable periods. The unrealized gain on commodity derivatives was $3.8 million and $2.9 million for the nine months ended September 30, 2011 and 2010, respectively. As commodity prices increase, the fair value of the open portion of those positions decreases. As commodity prices decrease, the fair value of the open portion of those positions increases. Historically, we have not designated our derivative instruments as cash-flow hedges. We record our open derivative instruments at fair value on our consolidated balance sheets as either unrealized gains or losses on commodity derivatives. We record changes in such fair value in net income on our consolidated statements of operations under the caption entitled unrealized gain (loss) on commodity derivatives.

Lease operating expenses. Our LOE increased $3.8 million, or 63%, for the nine months ended September 30, 2011, to $9.8 million ($5.81 per Boe) from $6 million ($5.39 per Boe) for the nine months ended September 30, 2010. The increase in LOE for the nine months ended September 30, 2011, was primarily attributable to the Working Interest Acquisition. In February 2011, we acquired the remaining 38% working interest in northern Project Pangea, which increased our working interest to approximately 100%. We also experienced an increase in water hauling, insurance and other expenses, as well as repair and maintenance expenses partially due to inclement winter weather in southwest Texas during the nine months ended September 30, 2011. The increase in LOE was partially offset by a decrease in compression and gas treating expense. For the remainder of 2011, we expect LOE to continue to be higher compared to the prior year period.

The following table summarizes LOE (per Boe).

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010	Change	% Change
Water hauling, insurance and other	$ 1.31	$ 1.16	$ 0.15	12.9%
Compression and gas treating	1.22	1.49	(0.27)	(18.1)
Ad valorem taxes	1.19	1.18	0.01	0.8
Well repairs and maintenance	1.12	0.60	0.52	86.7
Pumping and supervision	0.97	0.96	0.01	1.0
Total	$ 5.81	$ 5.39	$ 0.42	7.8%

Severance and production taxes. Our severance and production taxes increased $2.2 million, or 106%, for the nine months ended September 30, 2011, to $4.2 million from $2 million for the nine months ended September 30, 2010. The increase in severance and production taxes was primarily a function of the increase in oil, NGL and gas sales between the two periods. Severance and production taxes were approximately 5.5% and 5.0% of oil, NGL and gas sales for the respective periods. For the remainder of 2011, we expect severance and production taxes as a percent of oil, NGL and gas sales will remain relatively consistent compared to the nine months ended September 30, 2011.

Exploration. We recorded $6.9 million ($4.07 per Boe) and $2.2 million ($2.00 per Boe) of exploration expense for the nine months ended September 30, 2011 and 2010, respectively. Exploration expense for the nine months ended September 30, 2011, resulted primarily from lease extensions and expirations in the Permian Basin and the acquisition of 3-D seismic data in Pangea West. During the three months ended March 31, 2011, we extended the acreage terms for an additional four years for approximately 9,200 acres in the northwest area of Project Pangea for $3.2 million, or approximately $350 per acre. Further, approximately 5,000 acres in the southeast area of Project Pangea expired during the three months ended March 31, 2011, resulting in approximately $1.2 million of exploration expense. We expect exploration expense to increase from 2010 levels during the remainder of 2011 due to 3-D seismic activity in Pangea West and Project Pangea. Exploration expense for the nine months ended September 30, 2010, resulted primarily from our acquisition of 3-D seismic data across Cinco Terry.

General and administrative. Our G&A increased $4 million, or 50%, to $11.9 million ($7.03 per Boe) for the nine months ended September 30, 2011, from $7.9 million ($7.06 per Boe) for the nine months ended September 30, 2010. The increase in G&A was principally due to higher share-based compensation, salaries and benefits and professional fees. As discussed in Note 8 to our financial statements in this report, during the nine months ended September 30, 2011, we recognized $1.8 million in share-based compensation expense related to a grant of 204,000 restricted shares of common stock to our executive officers. For 2011, we expect G&A to be higher, compared to 2010, as a result of higher share-based compensation and staffing increases during 2010. Higher production volumes during the nine months ended September 30, 2011, however, resulted in consistent G&A per Boe, compared to the nine months ended September 30, 2010.

The following table summarizes G&A (in millions and per Boe).

	Nine Months Ended September 30,						
	2011		2010		Change		
	$MM	Boe	$MM	Boe	$MM	Boe	% Change
Salaries and benefits	$ 4.5	$ 2.63	$ 3.3	$ 2.90	$ 1.2	$ (0.27)	(9.3)%
Share-based compensation	3.6	2.15	2.0	1.82	1.6	0.33	18.1
Professional fees	1.1	0.64	1.0	0.87	0.1	(0.23)	(26.4)
Other	2.7	1.61	1.6	1.47	1.1	0.14	9.5
Total	$ 11.9	$ 7.03	$ 7.9	$ 7.06	$ 4.0	$ (0.03)	(0.4)%

Depletion, depreciation and amortization. Our DD&A increased $5.7 million, or 34%, to $22.4 million for the nine months ended September 30, 2011, from $16.7 million for the nine months ended September 30, 2010. The increase in DD&A expense over the prior year period was primarily due to an increase in capital expenditures in the nine months ended September 30, 2011. Our DD&A per Boe decreased by $1.63, or 11%, to $13.26 per Boe for the nine months ended September 30, 2011, compared to $14.89 per Boe for the nine months ended September 30, 2010. The decrease in DD&A per Boe was primarily attributable to an increase in estimated proved developed reserves, partially offset by an increase in production and capitalized costs over the prior year period.

Interest expense, net. Our interest expense, net, increased $760,000, or 47%, to $2.4 million for the nine months ended September 30, 2011, from $1.6 million for the nine months ended September 30, 2010. This increase was the result of a higher average debt level in the 2011 period. For the remainder of 2011, we expect interest expense to continue to be higher compared to the prior year period.

Income taxes. Our income taxes increased $5.1 million, or 125%, to $9.1 million for the nine months ended September 30, 2011, from $4 million for the nine months ended September 30, 2010. The increase in income taxes was due to higher net income in the 2011 period. Our effective income tax rate for the nine months ended September 30, 2011, was 35.6% compared with 36.0% for the nine months ended September 30, 2010.

Liquidity and Capital Resources

We generally will rely on cash generated from operations, borrowings under our revolving credit facility and, to the extent that credit and capital market conditions will allow, future public or private equity and debt offerings to satisfy our liquidity needs. Our ability to fund planned capital expenditures and to make acquisitions depends upon our future operating performance, availability of borrowings under our revolving credit facility, and more broadly, on the availability of equity and debt financing, which is affected by prevailing economic conditions in our industry and financial, business and other factors, some of which are beyond our control. We cannot predict whether additional liquidity from equity or debt financings beyond our revolving credit facility will be available on acceptable terms, or at all, in the foreseeable future.

Our cash flows from operations are driven by commodity prices, production volumes and the effect of commodity derivatives. Prices for oil and gas are affected by national and international economic and political environments, national and global supply and demand for hydrocarbons, seasonal influences of weather and other factors beyond our control. Cash flows from operations are primarily used to fund exploration and development of our oil and gas properties.

We believe we have adequate liquidity from cash generated from operations and unused borrowing capacity under our revolving credit facility for current working capital needs and maintenance of our current drilling program. However, we may determine to access the public or private equity or debt markets for future development of reserves, acquisitions, expansion of our current drilling program, additional working capital, repayment of borrowings or other liquidity needs, if such financing is available on acceptable terms. We cannot guarantee that financing will be available on acceptable terms or at all.

Liquidity

We define liquidity as funds available under our revolving credit facility plus cash and cash equivalents. At September 30, 2011, we had $122 million in long-term debt outstanding. We had no long-term debt outstanding at December 31, 2010. Our liquidity was $78.4 million and $173.1 million at September 30, 2011 and December 31, 2010, respectively. Effective October 7, 2011, we entered into an eleventh amendment to our credit agreement, which, among other things, increased our borrowing base 30% to $260 million from $200 million. Including the increase in our borrowing base, our liquidity would have been $138.4 million at September 30, 2011.

The table below summarizes our liquidity position at September 30, 2011 and December 31, 2010 (dollars in thousands).

	Liquidity with Borrowing Base Increase at September 30, 2011	Liquidity at September 30, 2011	Liquidity at December 31, 2010
Borrowing base	$ 260,000	$ 200,000	$ 150,000
Cash and cash equivalents	736	736	23,465
Long-term debt	(122,000)	(122,000)	
Unused letters of credit	(350)	(350)	(350)
Liquidity	$ 138,386	$ 78,386	$ 173,115

Working Capital

Our working capital is affected primarily by our cash and cash equivalents balance and our capital expenditure program. We had a working capital deficit of $27 million at September 30, 2011, compared to a working capital surplus of $12.1 million at December 31, 2010. The primary reason for the change in working capital was the use of cash to partially fund the Working Interest Acquisition and an increase in accounts payable relating to expenditures for drilling and development in our core operation area in the Permian Basin. As a result of the Working Interest Acquisition and our planned capital expenditure budget for 2011, we expect to continue to operate and end the year 2011 with a working capital deficit. Historically, our working capital deficits have been substantially attributable to current payables and accrued liabilities and have been more than offset by liquidity available under our revolving credit facility. To the extent we operate or end the year 2011 with a working capital deficit, we expect such deficit to be more than offset by liquidity available under our revolving credit facility.

Cash Flows

The following table summarizes our sources and uses of funds for the periods noted (in thousands).

	Nine Months Ended September 30,	
	2011	**2010**
Cash flows provided by operating activities	$ 74,214	$ 32,455
Cash flows used in investing activities	(218,546)	(53,115)
Cash flows provided by financing activities	121,630	18,396
Effect of Canadian exchange rate	(27)	(4)
Net decrease in cash and cash equivalents	$ (22,729)	$ (2,268)

For the nine months ended September 30, 2011, our primary sources of cash were from financing activities and operating activities. Approximately $121.6 million of cash from financing activities and $74.2 million of cash from operations were used to fund a portion of our drilling program.

Operating Activities

For the nine months ended September 30, 2011, our cash flows from operations, borrowings under our revolving credit facility and available cash were used primarily for drilling activities and leasehold acquisitions in our operating area in the Permian Basin. Cash flows from operating activities increased by 129%, or $41.8 million, to $74.2 million from the 2010 period primarily due to a 87% increase in oil, NGL and gas sales in the 2011 period.

Investing Activities

Cash flows used in investing activities increased by $165 million for nine months ended September 30, 2011, compared to the 2010 period, which primarily reflects the acquisition of the remaining 38% working interest in northern Project Pangea for $70.2 million, net of purchase price adjustments, and expenditures for drilling and lease acquisitions in our core operating area in the Permian Basin.

Financing Activities

Proceeds from borrowings, net of debt issuance costs, were $168.3 million and $81 million, respectively, under our revolving credit facility during the nine months ended September 30, 2011 and 2010, respectively. We repaid a total of $47.2 million and $62.7 million, respectively, of amounts outstanding under our revolving credit facility during the nine months ended September 30, 2011 and 2010, respectively. In addition, in the nine months ended September 30, 2011, we realized proceeds of $505,000 from the exercise of stock options.

Our current goal is to manage our borrowings to help us maintain financial flexibility and liquidity and to avoid the problems associated with highly-leveraged companies with large interest costs and possible debt reductions restricting ongoing operations.

Capital Expenditures

2011 Capital Expenditures

Total capital expenditures in 2011 are expected to be $260 million, with approximately $160.7 million allocated to drilling and completion projects in the Permian Basin, approximately $70.2 million allocated to the acquisition of the remaining 38% working interest in northern Project Pangea, approximately $29.1 million allocated to lease acquisitions, extensions and renewals in the Permian Basin, acquisition of 3-D seismic in Project Pangea and Pangea West, infrastructure and other expenditures.

2012 Capital Expenditures

The Company s Board of Directors approved a 2012 capital budget of $160 million for drilling and recompletions in the Permian Basin. The capital budget excludes acquisitions, and assumes an activity level similar to the Company s 2011 program, including two vertical rigs, one horizontal rig and four recompletions per month.

Our 2011 and 2012 capital budgets are subject to change depending upon a number of factors, including economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil, NGLs and gas, the availability of sufficient capital resources for drilling prospects, our financial results and the availability of lease extensions and renewals on reasonable terms.

Revolving Credit Facility

At September 30, 2011, we had a $300 million revolving credit facility with a borrowing base set at $200 million. The borrowing base is redetermined semi-annually on or before each April 1 and October 1 based on our oil, NGL and gas reserves. We or the lenders can each request one additional borrowing base redetermination each calendar year.

The maturity date under our revolving credit facility is July 31, 2014. Borrowings bear interest based on the agent bank s prime rate plus an applicable margin ranging from 0.75% to 1.75%, or the sum of the Eurodollar rate plus an applicable margin ranging from 1.75% to 2.75%. Margins vary based on the borrowings outstanding compared to the borrowing base. In addition, we pay an annual commitment of 0.50% of unused borrowings available under our revolving credit facility.

Effective October 7, 2011, we entered into an eleventh amendment to our credit agreement, which, among other things, (i) increased the borrowing base to $260 million from $200 million, and (ii) added Wells Fargo Bank, N.A. as a sixth lender to the bank syndicate.

We had outstanding borrowings of $122 million under our revolving credit facility at September 30, 2011. We had no outstanding borrowings at December 31, 2010. The interest rate applicable to our revolving credit facility at September 30, 2011, was 2.8%. We also had outstanding unused letters of credit under our revolving credit facility totaling $350,000 at September 30, 2011, which reduce amounts available for borrowing under our revolving credit facility.

Loans under our revolving credit facility are secured by first priority liens on substantially all of our West Texas assets and are guaranteed by our subsidiaries.

Covenants

Our credit agreement contains two principal financial covenants:

- a consolidated modified current ratio covenant that requires us to maintain a ratio of not less than 1.0 to 1.0 at all times. The consolidated modified current ratio is calculated by dividing Consolidated Current Assets (as defined in the credit agreement) by Consolidated Current Liabilities (as defined in the credit agreement). As defined more specifically in the credit agreement, the consolidated modified current ratio is calculated as current assets less current unrealized gains on commodity derivatives plus the available borrowing base at the respective balance sheet date, divided by current liabilities less current unrealized losses on commodity derivatives at the respective balance sheet date.

- a consolidated funded debt to consolidated EBITDAX ratio covenant that requires us to maintain a ratio of not more than 4.0 to 1.0 at the end of each fiscal quarter. The consolidated funded debt to consolidated EBITDAX ratio is calculated by dividing Consolidated Funded Debt (as defined in the credit agreement) by Consolidated EBITDAX (as defined in the credit agreement). As defined more specifically in the credit agreement, consolidated EBITDAX is calculated as net income (loss), plus (1) exploration expense, (2) depletion, depreciation and amortization expense, (3) share-based compensation expense, (4) unrealized loss on commodity derivatives, (5) interest expense, (6) income and franchise taxes and (7) certain other noncash expenses, less (x) gains or losses from sales or dispositions of assets, (y) unrealized gain on commodity derivatives and (z) extraordinary or nonrecurring gains. For purposes of calculating this ratio, consolidated EBITDAX for a fiscal quarter is annualized pursuant to the credit agreement.

Our credit agreement also restricts cash dividends and other restricted payments, transactions with affiliates, incurrence of other debt, consolidations and mergers, the level of operating leases, assets sales, investments in other entities and liens on properties.

In addition, our credit agreement contains customary events of default that would permit our lenders to accelerate the debt under our credit agreement if not cured within applicable grace periods, including, among others, failure to make payments of principal or interest when due, materially incorrect representations and warranties, failure to make mandatory prepayments in the event of borrowing base deficiencies, breach of covenants, defaults upon other obligations in excess of $500,000, events of bankruptcy, the occurrence of one or more unstayed judgments in excess of $500,000 not covered by an acceptable policy of insurance, failure to pay any obligation in excess of $500,000 owed under any derivatives transaction or in any amount if the obligation under the derivatives transaction is secured by collateral under the credit agreement, any event of default by the Company occurs under any agreement entered into in connection with a derivatives transaction, liens securing the loans under the credit agreement cease to be in place, a Change in Control (as defined in the credit agreement) of the Company occurs, and dissolution of the Company.

At September 30, 2011, we were in compliance with all of our covenants and had not committed any acts of default under the credit agreement.

To date we have experienced no disruptions in our ability to access our revolving credit facility. However, our lenders have substantial ability to reduce our borrowing base on the basis of subjective factors, including the loan collateral value that each lender assigns to our properties, using its discretion and methodology, assumptions and discount rates as such lender customarily uses in evaluating oil and gas properties.

Contractual Obligations

Our contractual obligations include long-term debt, daywork drilling contracts, service contracts, operating lease obligations, asset retirement obligations and employment agreements with our executive officers. Since December 31, 2010, there have been no material changes to our contractual obligations other than, as discussed in Note 4 to our financial statements in this report, an increase in outstanding borrowings under our credit agreement to $122 million at September 30, 2011. In addition, as discussed in Note 5 to our financial statements in this report, we have entered into an 18-month contract for a dedicated, third-party fracture stimulation fleet, effective September 1, 2011. The contract requires a minimum commitment of $3 million per month for the contract term. The contract contains customary, early termination provisions for a monthly fee of less than the minimum monthly commitment in the event of a termination before the end of the contract term.

Off-Balance Sheet Arrangements

From time to time, we enter into off-balance sheet arrangements and transactions that can give rise to off-balance sheet obligations. As of September 30, 2011, the off-balance sheet arrangements and transactions that we have entered into include undrawn letters of credit, operating lease agreements and gas delivery commitments. We do not believe that these arrangements have or are reasonably likely to have a current or future material effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

General Trends and Outlook

Our financial results depend upon many factors, particularly the price of oil, NGLs and gas. Commodity prices are affected by changes in market demand, which is impacted by overall economic activity, weather, pipeline capacity constraints, estimates of inventory storage levels, gas price differentials and other factors. As a result, we cannot accurately predict future oil, NGL and gas prices, and therefore, we cannot determine what effect increases or decreases will have on our capital program, production volumes and future revenues. A substantial or extended decline in oil, NGL and gas prices could have a material adverse effect on our business, financial condition, results of operations, quantities of oil and gas reserves that may be economically produced and liquidity that may be accessed through our borrowing base under our revolving credit facility and through capital markets.

In addition to production volumes and commodity prices, finding and developing sufficient amounts of oil and gas reserves at economical costs are critical to our long-term success. Future finding and development costs are subject to changes in the industry, including the costs of acquiring, drilling and completing our projects. We focus our efforts on increasing oil, NGL and gas reserves and production while controlling costs at a level that is appropriate for long-term operations. Our future cash flow from operations will depend on our ability to manage our overall cost structure.

Like all oil and gas production companies, we face the challenge of natural production declines. Oil and gas production from a given well naturally decreases over time. Additionally, our reserves have a rapid initial decline. We attempt to overcome this natural decline by drilling to develop and identify additional reserves, farm-ins or other joint drilling ventures, and by acquisitions. However, during times of severe price declines, we may from time to time reduce current capital expenditures and curtail drilling operations in order to preserve liquidity. A material reduction in capital expenditures and drilling activities could materially reduce our production volumes and revenues and increase future expected costs necessary to develop existing reserves.

We also face the challenge of financing exploration, development and future acquisitions. We believe we have adequate liquidity from cash generated from operations and unused borrowing capacity under our revolving credit facility for current working capital needs and maintenance of our current drilling program. However, we may determine to access the public or private equity or debt markets for future development of reserves, acquisitions, expansion of our current drilling program, additional working capital or other liquidity needs, if such financing is available on acceptable terms. We cannot guarantee that such financing will be available on acceptable terms or at all.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Some of the information below contains forward-looking statements. The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in oil and gas prices, and other related factors. The disclosure is not meant to be a precise indicator of expected future losses, but rather an indicator of reasonably possible losses. This forward-looking information provides an indicator of how we view and manage our ongoing market risk exposures. Our market risk sensitive instruments were entered into for commodity derivative and investment purposes, not for trading purposes.

Commodity Price Risk

Given the current economic outlook, we expect commodity prices to remain volatile. Even modest decreases in commodity prices can materially affect our revenues and cash flow. In addition, if commodity prices remain suppressed for a significant amount of time, we could be required under successful efforts accounting rules to perform a write down of our oil and gas properties.

We enter into financial swaps, options and collars to reduce the risk of commodity price fluctuations. We do not designate such instruments as cash flow hedges. Accordingly, we record open commodity derivative positions on our consolidated balance sheets at fair value and recognize changes in such fair values as other income (expense) on our consolidated statements of operations as they occur.

The following table sets forth our commodity derivative volumes and prices for 2011 and 2012.

Period	Contract Type	Volume Transacted	Contract Price
Natural Gas			
2011	Swap	230,000 MMBtu/month	$4.86
June 2011 December 2011	Swap	200,000 MMBtu/month	$4.74
2012	Call	230,000 MMBtu/month	$6.00
Natural Gas Basis Differential			
2011	Swap	300,000 MMBtu/month	$(0.53)
Crude Oil			
May 2011 December 2011	Collar	1,000 Bbls/day	$100.00 - $127.00

In October 2011, we added to its 2012 commodity derivatives positions with a crude oil collar contract covering 700 Bbls/d at a contract price of $85.00/Bbl $97.50/Bbl.

At September 30, 2011, the fair value of our open derivative contracts was a net asset of approximately $2.7 million. At December 31, 2010, the fair value of our open derivative contracts was a net liability of approximately $1.1 million.

JPMorgan Chase Bank, National Association (JPMorgan) and KeyBank National Association (KeyBank) are currently the only counterparties to our commodity derivatives positions. We are exposed to credit losses in the event of nonperformance by counterparties on our commodity derivatives positions. However, we do not anticipate nonperformance by the counterparties over the term of the commodity derivatives positions. JPMorgan is the administrative agent and a participant, and KeyBank is a participant, in our revolving credit facility, and the collateral for the outstanding borrowings under our revolving credit facility is used as collateral for our commodity derivatives.

Unrealized gains and losses, at fair value, are included on our consolidated balance sheets as current or noncurrent assets or liabilities based on the anticipated timing of cash settlements under the related contracts. Changes in the fair value of our commodity derivative contracts are recorded in net income as they occur and included in other income (expense) on our consolidated statements of operations. We estimate the fair values of contracts based on the present value of the difference in exchange-quoted forward price curves and contractual settlement prices multiplied by notional quantities. We use our internal valuations to determine the fair values of the contracts that are reflected on our consolidated balance sheets. Realized gains and losses are also included in other income (expense) on our consolidated statements of operations.

For the nine months ended September 30, 2011 and 2010, we recorded an unrealized gain on commodity derivatives of $3.8 million and $2.9 million, respectively, from the change in fair value of our commodity derivatives positions. A hypothetical 10% increase in commodity prices would have resulted in a $1.1 million decrease in the fair value of our commodity derivative positions recorded on our balance sheet at September 30, 2011, and a corresponding decrease in the unrealized gain on commodity derivatives recorded on our consolidated statement of operations for the nine months ended September 30, 2011.

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in the reports we file under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. Such controls include those designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is accumulated and communicated to management, including the President and Chief Executive Officer (CEO) and Chief Financial Officer (CFO), as appropriate, to allow timely decisions regarding required disclosure.

Our management, with the participation of our CEO and CFO, has evaluated the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) promulgated under the Exchange Act) as of September 30, 2011. Based on this evaluation, the CEO and CFO have concluded that, as of September 30, 2011, our disclosure controls and procedures were effective, in that they ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is (1) recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and (2) accumulated and communicated to our management, including our CEO and CFO, as appropriate to allow timely decisions regarding required disclosure.

Internal Control over Financial Reporting

There were no changes made in our internal control over financial reporting (as defined in Rule 13a-15(f) promulgated under the Exchange Act) during the three months ended September 30, 2011, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Limitations Inherent in All Controls

Our management, including the CEO and CFO, recognizes that the disclosure controls and procedures and internal controls (discussed above) cannot prevent all errors or all attempts at fraud. Any controls system, no matter how well crafted and operated, can only provide reasonable, and not absolute, assurance of achieving the desired control objectives. Because of the inherent limitations in any control system, no evaluation or implementation of a control system can provide complete assurance that all control issues and all possible instances of fraud have been, or will be, detected.

PART II OTHER INFORMATION

Item 1. Legal Proceedings.

The information set forth in Note 5 of Part I, Item 1 of this report regarding *Approach Operating, LLC v. EnCana Oil & Gas (USA) Inc., Cause No. 29.070*, is incorporated herein by reference. Except as set forth in Note 5 of Part I, Item 1 of this Quarterly Report on Form 10-Q, there have been no material developments in the legal proceedings described in Part I, Item 3. Legal Proceedings of our Annual Report on Form 10-K for the year ended December 31, 2010, filed with the SEC on March 11, 2011.

Item 1A. Risk Factors.

In addition to the other information set forth in this report, you should carefully consider the risks discussed in our Annual Report on Form 10-K for the year ended December 31, 2010, filed with the SEC on March 11, 2011, under the headings Item 1. Business Markets and Customers; Competition; and Regulation, Item 1A. Risk Factors, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations General Trends and Outlook and Item 7A. Quantitative and Qualitative Disclosures about Market Risk. These risks could materially affect our business, financial condition and results of operations.

Except as provided below, there have been no material changes to the risk factors discussed in our Annual Report on Form 10-K for the year ended December 31, 2010, filed with the SEC on March 11, 2011, which is accessible on the SEC s website at *www.sec.gov* and our website at *www.approachresources.com.*

The adoption of additional federal and state legislative and regulatory initiatives related to hydraulic fracturing could result in operating restrictions or delays in the completion of oil and gas wells.

We currently conduct all of our operations in Texas. Texas and other states have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure and well construction requirements on hydraulic fracturing operations or otherwise seek to ban hydraulic fracturing activities altogether. In August 2011, the Railroad Commission of Texas proposed new rules requiring disclosure of the composition of hydraulic fracturing fluids and total volume of water used in the hydraulic fracturing process. In addition to state laws, rules and regulations, local land use restrictions, such as city or county ordinances, may restrict or prohibit drilling in general or hydraulic fracturing in particular. The adoption of state, local or municipal laws, rules or regulations in areas where we operate may cause us to incur additional, and potentially significant, compliance costs, to experience delays in our exploration, development or production activities, or to be precluded from the drilling of wells.

There are also certain governmental reviews either underway or being proposed that focus on the environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. Further, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The Environmental Protection Agency (EPA) has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. In addition, the U.S. Department of Energy is conducting an investigation into practices the agency could recommend to improve the safety and environmental performance of hydraulic fracturing methods. Also, the U.S. Department of the Interior is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands.

In July 2011, the EPA proposed rules that would establish new air emission controls for oil and gas production and natural gas processing operations. Specifically, the EPA s proposed rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds (VOCs) and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and gas production and processing activities. The EPA s proposal would require the reduction of VOC emissions from oil and gas production facilities by requiring the use of green completions for hydraulic fracturing, which requires the operator to recover rather than vent the natural gas and natural gas liquids that come to the surface during the hydraulic fracturing process. The proposed rules also would establish specific requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. The EPA will receive public comment and hold hearings regarding the proposed rules and take final action by February 28, 2012. If finalized, these rules could require a number of modifications to our operations, including the installation of new equipment. Compliance with such rules could result in additional capital expenditures and operating costs.

In October 2011, the EPA announced that it intends to develop national standards for wastewater discharges produced by natural gas extraction from shale and coalbed methane formations. For shale gas wastewater, the EPA will consider imposing pre-treatment standards for discharges to a wastewater treatment facility. Produced and other flowback water from our current operations in the Permian Basin is typically re-injected into underground formations that do not contain potable water. To the extent that re-injection is not available for our operations and discharge to wastewater treatment facilities is required, new standards from the EPA could increase the cost of disposing wastewater in connection with our operations.

Certain members of Congress have called upon (i) the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, (ii) the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of developing shale gas reserves including by means of hydraulic fracturing, and (iii) the U.S. Energy Information Administration to provide a better understanding of that agency s estimates regarding natural gas reserves, as well as uncertainties associated with those estimates. These ongoing or proposed investigations and studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory means.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities that use hydraulic fracturing. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and gas, or could make it more difficult to use hydraulic fracturing. The adoption of any federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells and increased compliance costs and time, which could adversely affect our business, financial condition, results of operations and cash flows.

Our ability to produce oil and gas economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling and completions operations or are unable to dispose of or recycle the water we use at a reasonable cost and in accordance with applicable environmental laws, rules and regulations.

The hydraulic fracturing processes that we use to produce oil and gas from the Wolffork oil shale play in the Permian Basin requires the use and disposal of significant quantities of water. Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, could adversely impact our operations in this region. Moreover, new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas.

Compliance with environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of our wells may increase our operating costs and cause delays, interruptions or cessation of our operations, the extent of which cannot be predicted, and all of which could have an adverse effect on our business, financial condition, results of operations and cash flows.

Current SEC rules could require us to write down our proved undeveloped reserves in the future.

The current SEC rules require that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years. These rules may require us to write down our proved undeveloped reserves if we do not drill certain wells within the required five-year timeframe.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

The following table provides information relating to our purchase of shares of our common stock during the three months ended September 30, 2011. The repurchases reflect shares withheld upon vesting of restricted stock under our 2007 Stock Incentive Plan to satisfy statutory minimum tax withholding obligations.

ISSUER PURCHASES OF EQUITY SECURITIES

Period	**(a) Total Number of Shares Purchased**	**(b) Average Price Paid Per Share**	**(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs**	**(d) Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs**
Month #1 July 1, 2011 July 31, 2011	2,645	$ 26.07		
Month #2 August 1, 2011 August 31, 2011	1,613	$ 20.33		
Month #3 September 1, 2011 September 30, 2011				
Total	4,258	$ 23.90		

Item 6. Exhibits.

See Index to Exhibits following the signature page of this report for a description of the exhibits furnished as part of this report.

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.

	APPROACH RESOURCES INC.
Date: November 7, 2011	By: /s/ J. Ross Craft J. Ross Craft President and Chief Executive Officer (Principal Executive Officer)
Date: November 7, 2011	By: /s/ Steven P. Smart Steven P. Smart Executive Vice President and Chief Financial Officer (Principal Financial and Chief Accounting Officer)

Index to Exhibits

Exhibit Number	*Description of Exhibit*
3.1	Restated Certificate of Incorporation of Approach Resources Inc. (filed as Exhibit 3.1 to the Company s Quarterly Report on Form 10-Q filed December 13, 2007, and incorporated herein by reference).
3.2	Restated Bylaws of Approach Resources Inc. (filed as Exhibit 3.2 to the Company s Quarterly Report on Form 10-Q filed December 13, 2007, and incorporated herein by reference).
4.1	Specimen Common Stock Certificate (filed as Exhibit 4.1 to the Company s Registration Statement on Form S-1/A filed October 18, 2007 (File No. 333-144512), and incorporated herein by reference).
10.1	Amendment No. 11 dated as of October 7, 2011, to Credit Agreement dated as of January 18, 2008, among Approach Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as administrative agent and lender, BNP Paribas, KeyBank National Association, The Frost National Bank, Royal Bank of Canada and Wells Fargo Bank, N.A., as lenders, and Approach Oil & Gas Inc. and Approach Resources I, LP, as guarantors (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K filed October 11, 2011, and incorporated herein by reference).
*31.1	Certification by the President and Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
**32.1	Certification by the President and Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**32.2	Certification by the Chief Financial Officer Pursuant to U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**101.INS	XBRL Instance Document.
**101.SCH	XBRL Taxonomy Extension Schema Document.
**101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
**101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
**101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

* Filed herewith.

** Furnished herewith.