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

FORM 10-Q
(Mark One)
☑ **Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the quarterly period ended June 30, 2014
OR

☐ **Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the transition period from _______ to ________

Commission file number: **001-12935**

DENBURY RESOURCES INC.

(Exact name of registrant as specified in its charter)

Delaware	**20-0467835**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
5320 Legacy Drive, **Plano, TX**	**75024**
(Address of principal executive offices)	*(Zip Code)*

Registrant's telephone number, including area code: **(972) 673-2000**

Not applicable
(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. Yes ☑ No ☐

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

Indicate by check mark 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. (Check one):

Large accelerated filer ☑	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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

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

Class	Outstanding at July 31, 2014
Common Stock, $.001 par value	352,289,302

Denbury Resources Inc.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Denbury Resources Inc.
Unaudited Condensed Consolidated Balance Sheets
(In thousands, except par value and share data)

	June 30, 2014	December 31, 2013
Assets		
Current assets		
Cash and cash equivalents	$ 12,046	$ 12,187
Accrued production receivable	287,283	262,047
Trade and other receivables, net	66,001	78,295
Derivative assets	—	5
Deferred tax assets	42,301	52,754
Other current assets	15,342	9,271
Total current assets	422,973	414,559
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved properties	9,374,871	8,945,326
Unevaluated properties	811,935	780,481
CO_2 properties	1,142,093	1,117,167
Pipelines and plants	2,225,917	2,209,560
Other property and equipment	465,882	466,969
Less accumulated depletion, depreciation, amortization and impairment	(3,949,275)	(3,668,225)
Net property and equipment	10,071,423	9,851,278
Derivative assets	94	9,942
Goodwill	1,283,590	1,283,590
Other assets	221,597	229,368
Total assets	$ 11,999,677	$ 11,788,737
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 342,397	$ 410,543
Oil and gas production payable	172,644	174,677
Derivative liabilities	185,454	53,822
Current maturities of long-term debt	35,533	36,157
Total current liabilities	736,028	675,199
Long-term liabilities		
Long-term debt, net of current portion	3,602,156	3,260,625
Asset retirement obligations	119,383	119,888
Derivative liabilities	36,027	3,413
Deferred tax liabilities	2,390,501	2,399,294
Other liabilities	27,636	28,912
Total long-term liabilities	6,175,703	5,812,132
Commitments and contingencies (Note 7)		
Stockholders' equity		
Preferred stock, $.001 par value, 25,000,000 shares authorized, none issued and outstanding	—	—
Common stock, $.001 par value, 600,000,000 shares authorized; 411,396,702 and 409,215,573 shares issued, respectively	411	409
Paid-in capital in excess of par	3,213,920	3,186,714
Retained earnings	2,803,876	2,844,432
Accumulated other comprehensive loss	(244)	(276)
Treasury stock, at cost, 59,070,861 and 46,710,896 shares, respectively	(930,017)	(729,873)
Total stockholders' equity	5,087,946	5,301,406
Total liabilities and stockholders' equity	$ 11,999,677	$ 11,788,737

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

Denbury Resources Inc.
Unaudited Condensed Consolidated Statements of Operations
(In thousands, except per share data)

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Revenues and other income				
Oil, natural gas, and related product sales	$ 657,029	$ 638,188	$ 1,280,875	$ 1,211,841
CO_2 and helium sales and transportation fees	11,822	6,562	22,583	13,120
Interest income and other income	3,269	5,334	10,406	8,209
Total revenues and other income	672,120	650,084	1,313,864	1,233,170
Expenses				
Lease operating expenses	163,250	220,558	333,629	361,100
Marketing and plant operating expenses	18,149	13,332	34,935	23,128
CO_2 and helium discovery and operating expenses	5,590	3,419	10,795	7,141
Taxes other than income	50,850	44,940	96,795	82,951
General and administrative expenses	38,952	33,382	82,645	75,271
Interest, net of amounts capitalized of $5,795, $23,279, $11,551, and $44,984, respectively	46,550	30,602	95,384	66,636
Depletion, depreciation, and amortization	148,164	126,907	289,294	239,805
Commodity derivatives expense (income)	174,771	(45,501)	251,440	(33,572)
Loss on early extinguishment of debt	113,908	428	113,908	44,651
Other expenses	—	10,711	—	12,818
Total expenses	760,184	438,778	1,308,825	879,929
Income (loss) before income taxes	(88,064)	211,306	5,039	353,241
Income tax provision (benefit)	(32,864)	81,326	1,929	135,690
Net income (loss)	$ (55,200)	$ 129,980	$ 3,110	$ 217,551
Net income (loss) per common share				
Basic	$ (0.16)	$ 0.35	$ 0.01	$ 0.59
Diluted	$ (0.16)	$ 0.35	$ 0.01	$ 0.58
Dividends per common share	$ 0.0625	$ —	$ 0.1250	$ —
Weighted average common shares outstanding				
Basic	347,803	368,850	349,267	369,122
Diluted	347,803	371,969	351,566	372,417

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

Denbury Resources Inc.
Unaudited Condensed Consolidated Statements of Comprehensive Operations
(In thousands)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net income (loss)	$ (55,200)	$ 129,980	$ 3,110	$ 217,551
Other comprehensive income, net of income tax:				
Interest rate lock derivative contracts reclassified to income, net of tax of $11, $11, $24, and $19, respectively	17	17	32	37
Total other comprehensive income	17	17	32	37
Comprehensive income (loss)	$ (55,183)	$ 129,997	$ 3,142	$ 217,588

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

Denbury Resources Inc.
Unaudited Condensed Consolidated Statements of Cash Flows
(In thousands)

	Six Months Ended June 30,	
	2014	**2013**
Cash flows from operating activities		
Net income	$ 3,110	$ 217,551
Adjustments to reconcile net income to cash flow from operating activities		
Depletion, depreciation, and amortization	289,294	239,805
Deferred income taxes	1,611	128,342
Stock-based compensation	17,217	15,671
Commodity derivatives expense (income)	251,440	(33,572)
Settlements of commodity derivatives	(77,341)	—
Loss on early extinguishment of debt	113,908	44,651
Amortization of debt issuance costs and discounts	6,978	7,139
Other, net	(3,402)	5,097
Changes in assets and liabilities, net of effects from acquisitions:		
Accrued production receivable	(25,236)	(6,769)
Trade and other receivables	12,921	3,117
Other current and long-term assets	(2,989)	(9,171)
Accounts payable and accrued liabilities	(36,178)	86,969
Oil and natural gas production payable	(2,033)	20,222
Other liabilities	(4,595)	(12,308)
Net cash provided by operating activities	544,705	706,744
Cash flows from investing activities		
Oil and natural gas capital expenditures	(451,564)	(486,163)
CO_2 capital expenditures	(29,901)	(44,708)
Pipelines and plants capital expenditures	(34,530)	(97,480)
Purchases of other assets	(3,620)	(22,825)
Net proceeds from sales of oil and natural gas properties and equipment	1,736	5,496
Other	977	(19,893)
Net cash used in investing activities	(516,902)	(665,573)
Cash flows from financing activities		
Bank repayments	(1,315,000)	(970,000)
Bank borrowings	1,420,000	530,000
Repayment of senior subordinated notes	(997,345)	(651,270)
Premium paid on repayment of senior subordinated notes	(101,342)	(36,475)
Proceeds from issuance of senior subordinated notes	1,250,000	1,200,000
Costs of debt financing	(17,551)	(20,026)
Common stock repurchase program	(211,356)	(100,423)
Dividends paid	(43,461)	—
Other	(11,889)	(15,623)
Net cash used in financing activities	(27,944)	(63,817)
Net decrease in cash and cash equivalents	(141)	(22,646)
Cash and cash equivalents at beginning of period	12,187	98,511
Cash and cash equivalents at end of period	$ 12,046	$ 75,865

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

Note 1. Basis of Presentation

Organization and Nature of Operations

Denbury Resources Inc., a Delaware corporation, is a growing, dividend-paying, domestic oil and natural gas company. Our primary focus is on enhanced oil recovery utilizing CO_2, and our operations are focused in two key operating areas: the Gulf Coast and Rocky Mountain regions. Our goal is to increase the value of our acquired properties through a combination of exploitation, drilling and proven engineering extraction practices, with the most significant emphasis relating to tertiary recovery operations.

Interim Financial Statements

The accompanying unaudited condensed consolidated financial statements of Denbury Resources Inc. and its subsidiaries have been prepared in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC") and do not include all of the information and footnotes required by accounting principles generally accepted in the United States for complete financial statements. These financial statements and the notes thereto should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2013 (the "Form 10-K"). Unless indicated otherwise or the context requires, the terms "we," "our," "us," "Company," or "Denbury," refer to Denbury Resources Inc. and its subsidiaries.

Accounting measurements at interim dates inherently involve greater reliance on estimates than at year end, and the results of operations for the interim periods shown in this report are not necessarily indicative of results to be expected for the year. In management's opinion, the accompanying unaudited condensed consolidated financial statements include all adjustments of a normal recurring nature necessary for a fair statement of our consolidated financial position as of June 30, 2014, our consolidated results of operations for the three and six months ended June 30, 2014 and 2013, and our consolidated cash flows for the six months ended June 30, 2014 and 2013.

Reclassifications

Certain prior period amounts have been reclassified to conform to the current year presentation. Such reclassifications had no impact on our reported net income, current assets, total assets, current liabilities, total liabilities or stockholders' equity.

Net Income (Loss) per Common Share

Basic net income (loss) per common share is computed by dividing the net income (loss) attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted net income (loss) per common share is calculated in the same manner, but includes the impact of potentially dilutive securities. Potentially dilutive securities consist of stock options, stock appreciation rights ("SARs"), nonvested restricted stock and nonvested performance equity awards. For the three and six months ended June 30, 2014 and 2013, there were no adjustments to net income for purposes of calculating basic or diluted net income per common share.

The following is a reconciliation of the weighted average shares used in the basic and diluted net income per common share calculations for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands	2014	2013	2014	2013
Basic weighted average common shares outstanding	347,803	368,850	349,267	369,122
Potentially dilutive securities:				
Restricted stock, stock options, SARs and performance-based equity awards	—	3,119	2,299	3,295
Diluted weighted average common shares outstanding	347,803	371,969	351,566	372,417

Basic weighted average common shares exclude shares of nonvested restricted stock. As these restricted shares vest, they will be included in the shares outstanding used to calculate basic net income per common share (although all restricted stock is issued and outstanding upon grant). For purposes of calculating diluted weighted average common shares during the six months ended June 30, 2014, and the three and six months ended June 30, 2013, the nonvested restricted stock is included in the computation using the treasury stock method, with the deemed proceeds equal to the average unrecognized compensation during the period, adjusted for any estimated future tax consequences recognized directly in equity. Restricted stock, stock options, SARs and performance-based equity awards aggregating 6.3 million shares for the three months ended June 30, 2014, were not included in the computation of weighted average common shares outstanding, as their effect would have been antidilutive to the net loss recorded for the period. Stock options and SARs of 4.1 million shares for the six months ended June 30, 2014, and 3.7 million shares for the three and six months ended June 30, 2013, were not included in the computation of diluted net income per share as their effect would have been antidilutive.

Recent Accounting Pronouncements

Revenue Recognition. In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2014-09, *Revenue from Contracts with Customers* ("ASU 2014-09"). ASU 2014-09 amends the guidance for revenue recognition to replace numerous, industry-specific requirements. The core principle of the ASU is that an entity should recognize revenue for the transfer of goods or services equal to the amount that it expects to be entitled to receive for those goods or services. The ASU implements a five-step process for customer contract revenue recognition that focuses on transfer of control, as opposed to transfer of risk and rewards. The amendment also requires enhanced disclosures regarding the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers. The amendments in this ASU are effective for reporting periods beginning after December 15, 2016, and early adoption is prohibited. Entities can transition to the standard either retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. Management is currently assessing the impact the adoption of ASU 2014-09 will have on our consolidated financial statements.

Discontinued Operations. In April 2014, the FASB issued ASU 2014-08, *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity* ("ASU 2014-08"). ASU 2014-08 amends the definition of a discontinued operation under the *Discontinued Operations* topic of the FASB Codification and requires entities to disclose additional information about discontinued operations and disposal transactions that do not meet the discontinued operations criteria. ASU 2014-08 will be applied prospectively for disposals of components of an entity and businesses or nonprofit activities that, on acquisition, are classified as held for sale that occur within annual periods beginning on or after December 15, 2014, and interim periods within those years. The adoption of ASU 2014-08 is currently not expected to have a material effect on our consolidated financial statements.

Note 2. Acquisitions and Divestitures

2013 Acquisition

Cedar Creek Anticline Acquisition. On March 27, 2013, we acquired producing assets in the Cedar Creek Anticline ("CCA") of Montana and North Dakota from a wholly-owned subsidiary of ConocoPhillips Company for $1.0 billion after final closing adjustments. This acquisition was not reflected as an Investing Activity on our Unaudited Condensed Consolidated Statement of Cash Flows for the six months ended June 30, 2013 due to the movement of the cash used to acquire these assets through a qualified intermediary to facilitate a like-kind-exchange treatment under federal income tax rules. This acquisition meets the definition of a business under the Financial Accounting Standards Board Codification ("FASC") *Business Combinations* topic. The fair values assigned to assets acquired and liabilities assumed in this acquisition have been finalized and no adjustments have been made to fair value amounts previously disclosed in our Form 10-K for the period ended December 31, 2013.

For the three months ended June 30, 2013 and for the period from March 27, 2013 to June 30, 2013, we recognized $88.7 million and $92.7 million of oil, natural gas, and related product sales, respectively, from the property interests acquired in the CCA acquisition. For the three months ended June 30, 2013 and for the period from March 27, 2013 to June 30, 2013, we recognized $65.2 million and $67.9 million of net field operating income (defined as oil, natural gas and related product sales less lease operating expenses, production and ad valorem taxes, and marketing expenses), respectively, related to the CCA acquisition.

Unaudited Pro Forma Acquisition Information. The following pro forma total revenues and other income and pro forma net income are presented as if the CCA acquisition had occurred on January 1, 2013:

In thousands, except per share data	Six Months Ended June 30, 2013
Pro forma total revenues and other income	$ 1,315,344
Pro forma net income	247,755
Pro forma net income per common share	
Basic	$ 0.67
Diluted	0.67

Note 3. Long-Term Debt

The following long-term debt and capital lease obligations were outstanding as of the dates indicated:

In thousands	June 30, 2014	December 31, 2013
Bank Credit Agreement	$ 445,000	$ 340,000
8¼% Senior Subordinated Notes due 2020	—	996,273
6⅜% Senior Subordinated Notes due 2021	400,000	400,000
5½% Senior Subordinated Notes due 2022	1,250,000	—
4⅝% Senior Subordinated Notes due 2023	1,200,000	1,200,000
Other Subordinated Notes, including premium of $13 and $16, respectively	2,747	3,823
Pipeline financings	224,171	228,167
Capital lease obligations	115,771	128,519
Total	3,637,689	3,296,782
Less: current obligations	(35,533)	(36,157)
Long-term debt and capital lease obligations	$ 3,602,156	$ 3,260,625

The ultimate parent company in our corporate structure, Denbury Resources Inc. ("DRI"), is the sole issuer of all of our outstanding senior subordinated notes. DRI has no independent assets or operations. Each of the subsidiary guarantors of such notes is 100% owned, directly or indirectly, by DRI; any subsidiaries of DRI other than the subsidiary guarantors are minor subsidiaries, and the guarantees of the notes are full and unconditional and joint and several.

$1.6 Billion Revolving Credit Agreement

In March 2010, we entered into a $1.6 billion revolving credit agreement with JPMorgan Chase Bank, N.A., as administrative agent, and other lenders party thereto (as amended, the "Bank Credit Agreement"). Availability under the Bank Credit Agreement is subject to a borrowing base, which is redetermined semi-annually on or around May 1 and November 1 of each year, and additionally upon requested special redeterminations. The borrowing base is adjusted at the lenders' discretion and is based in part upon external factors over which we have no control (including approval by the lenders party to the Bank Credit Agreement). If our outstanding credit under the Bank Credit Agreement exceeds the then effective borrowing base, we would be required to repay the excess amount over a period not to exceed four months. On April 15, 2014, we entered into the Twelfth Amendment to the Bank Credit Agreement to, among other modifications, increase the limit on the amount of Additional Permitted Subordinate Debt (as defined in the Bank Credit Agreement) that we may incur, as part of the April 2014 issuance of our $1.25 billion of 5½% Senior Subordinated Notes due 2022 (the "5½% Notes") (see *5½% Senior Subordinated Notes due 2022* below) and the refinancing of our $996.3 million of 8¼% Senior Subordinated Notes due 2020 (the "8¼% Notes"). As part of the semi-annual review completed in May 2014 pursuant to the terms of the Bank Credit Agreement, our borrowing base was reaffirmed at $1.6 billion effective May

7, 2014. Our next semi-annual redetermination is scheduled to occur on or around November 1, 2014. The weighted average interest rate on borrowings outstanding as of June 30, 2014 under the Bank Credit Agreement was 2.14%. We incur a commitment fee of either 0.375% or 0.5%, based on the ratio of outstanding credit to the borrowing base, on the unused availability under the Bank Credit Agreement. Loans under the Bank Credit Agreement mature in May 2016.

5½% Senior Subordinated Notes due 2022

On April 30, 2014, we issued $1.25 billion of 5½% Notes. The 5½% Notes, which bear interest at a rate of 5.5% per annum, were sold at 100% of the principal amount. The net proceeds, after issuance costs, of $1.23 billion were used to repurchase or redeem our outstanding 8¼% Notes, which were issued in 2010 (see *2014 Repurchase and Redemption of 8¼% Notes* below), and to pay down a portion of outstanding borrowings under our Bank Credit Agreement.

The 5½% Notes mature on May 1, 2022, and interest is payable on May 1 and November 1 of each year, commencing November 1, 2014. We may redeem the 5½% Notes in whole or in part at our option beginning May 1, 2017, at the following redemption prices: 104.125% on or after May 1, 2017; 102.75% on or after May 1, 2018; 101.375% on or after May 1, 2019; and 100% on or after May 1, 2020. Prior to May 1, 2017, we may at our option redeem up to an aggregate of 35% of the principal amount of the 5½% Notes at a price of 105.5% with the proceeds of certain equity offerings. In addition, at any time prior to May 1, 2017, we may redeem 100% of the principal amount of the 5½% Notes at a price equal to 100% of the principal amounts plus a "make whole" premium and accrued and unpaid interest. The indenture is generally consistent with the indenture for our 4⅝% Senior Subordinated Notes due 2023 (the "4⅝% Notes") and contains certain restrictions on our ability and the ability of our restricted subsidiaries to (1) incur additional debt; (2) make investments; (3) create liens on our assets or the assets of our restricted subsidiaries; (4) create restrictions on the ability of our restricted subsidiaries to pay dividends or make other payments to the Company or other restricted subsidiaries; (5) engage in transactions with our affiliates; (6) transfer or sell assets or subsidiary stock; (7) consolidate, merge or transfer all or substantially all of our assets and the assets of our restricted subsidiaries; and (8) make restricted payments (which includes paying dividends on our common stock or redeeming, repurchasing or retiring such stock or subordinated debt) unless certain leverage ratios are met.

2014 Repurchase and Redemption of 8¼% Notes

On April 30, 2014, we completed a cash tender offer for our 8¼% Notes and purchased a total of $815.2 million principal amount of these notes. We received sufficient consents in the solicitation to amend the indenture governing the 8¼% Notes by entering into a supplemental indenture, which eliminated most of the restrictive covenants and certain events of default. The purchase under this tender offer was funded by a portion of the proceeds from the sale of our 5½% Notes. On April 30, 2014, we issued a notice of redemption and fully funded the redemption of all of the remaining outstanding 8¼% Notes ($181.1 million principal amount) at an amount equal to 100% of their principal amount plus the required make-whole premium and accrued interest up to but excluding the May 30, 2014 redemption date, resulting in a satisfaction and discharge of the indenture for the 8¼% Notes.

We recognized a $113.9 million loss associated with the debt repurchases during the second quarter of 2014, which loss consists of both premium payments made to repurchase or redeem the 8¼% Notes and the elimination of unamortized debt issuance costs related to these notes. The loss is included in our Unaudited Condensed Consolidated Statement of Operations under the caption "Loss on early extinguishment of debt," and premium payments made to repurchase the notes are classified as a financing cash outflow on our Unaudited Condensed Consolidated Statements of Cash Flows under the caption "Premium paid on repayment of senior subordinated notes."

4⅝% Senior Subordinated Notes due 2023

In February 2013, we issued $1.2 billion of 4⅝% Notes. The 4⅝% Notes, which bear interest at a rate of 4.625% per annum, were sold at 100% of the principal amount. The net proceeds, after issuance costs, of $1.18 billion were used to repurchase or redeem our 9½% Senior Subordinated Notes due 2016 (the "9½% Notes") and our 9¾% Senior Subordinated Notes due 2016 (the "9¾% Notes") (see *2013 Repurchase and Redemption of 9½% Notes and 9¾% Notes* below) and to pay down a portion of outstanding borrowings under our Bank Credit Agreement.

2013 Repurchase and Redemption of 9½% Notes and 9¾% Notes

Pursuant to cash tender offers, we repurchased $426.4 million principal amount of our 9¾% Notes and $186.7 million principal amount of our 9½% Notes during the first quarter of 2013, and repurchased the remaining $38.2 million principal amount of our 9½% Notes during the second quarter of 2013. We recognized a loss associated with the debt repurchases of $0.4 million and $44.7 million during the three and six months ended June 30, 2013, respectively, consisting of both premium payments made to repurchase or redeem the notes and the elimination of unamortized debt issuance costs, discounts and premiums related to these notes. The loss is included in our Unaudited Condensed Consolidated Statement of Operations under the caption "Loss on early extinguishment of debt," and premium payments made to repurchase the notes are classified as a financing cash outflow on our Unaudited Condensed Consolidated Statements of Cash Flows under the caption "Premium paid on repayment of senior subordinated notes."

Note 4. Stockholders' Equity

Dividends

In each of the first two quarters of 2014, we paid a quarterly cash dividend to our common stockholders of $0.0625 per common share, with aggregate dividends of $43.5 million, or $0.125 per common share, paid during the six months ended June 30, 2014. See Note 8, *Subsequent Event*, for details regarding the dividend declared and to be paid in the third quarter of 2014.

Stock Repurchase Program

Under our board-authorized share repurchase program, we repurchased 12.4 million shares of Denbury common stock for $200.4 million during the first quarter of 2014. Since commencement of the share repurchase program in October 2011 through June 30, 2014, we have repurchased a total of 60.0 million shares of Denbury common stock for $940.0 million, or $15.68 per share. As of June 30, 2014, we were authorized to repurchase an additional $221.9 million of common stock under this repurchase program.

Note 5. Commodity Derivative Contracts

We do not apply hedge accounting treatment to our oil and natural gas derivative contracts; therefore, the changes in the fair values of these instruments are recognized in income in the period of change. These fair value changes, along with the cash settlements of expired contracts, are shown under "Commodity derivatives expense (income)" in our Unaudited Condensed Consolidated Statements of Operations.

From time to time, we enter into various oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production. We do not hold or issue derivative financial instruments for trading purposes. These contracts have consisted of price floors, collars, three-way collars, fixed-price swaps and fixed-price swaps enhanced with a sold put. The production that we hedge has varied from year to year depending on our levels of debt and financial strength and expectation of future commodity prices. We currently employ a strategy to hedge a portion of our forecasted production approximately 18 months to two years in the future from the current quarter, as we believe it is important to protect our future cash flow to provide a level of assurance for our capital spending and dividends in those future periods in light of current worldwide economic uncertainties and commodity price volatility.

We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures, and diversification, and all of our commodity derivative contracts are with parties that are lenders under our Bank Credit Agreement. As of June 30, 2014, all of our outstanding derivative contracts were subject to enforceable master netting arrangements whereby payables on those contracts can be offset against receivables from separate derivative contracts with the same counterparty. It is our policy to classify derivative assets and liabilities on a gross basis on our balance sheets, even if the contracts are subject to enforceable master netting arrangements.

The following table summarizes our commodity derivative contracts as of June 30, 2014, none of which are classified as hedging instruments in accordance with the FASC *Derivatives and Hedging* topic:

			Contract Prices (1)				
				Weighted Average Price			
Months	Index Price	Volume (2)	Range (3)	Swap	Sold Put	Floor	Ceiling
Oil Contracts:							
2014 Fixed-Price Swaps							
July – Sept	NYMEX	58,000	$ 90.00 – 93.50	$ 92.52	$ —	$ —	$ —
Oct – Dec	NYMEX	58,000	90.00 – 93.50	92.52	—	—	—
2015 Enhanced Swaps (4)							
Jan – Mar	NYMEX	14,000	$ 90.00 – 90.30	$ 90.06	$ 65.21	$ —	$ —
Jan – Mar	LLS	16,000	93.20 – 94.00	93.63	68.00	—	—
Apr – June	NYMEX	8,000	90.00 – 90.00	90.00	65.75	—	—
Apr – June	LLS	16,000	93.20 – 94.00	93.65	68.00	—	—
July – Sept	NYMEX	10,000	90.00 – 90.10	90.02	65.30	—	—
July – Sept	LLS	16,000	93.20 – 94.00	93.65	68.00	—	—
Oct – Dec	NYMEX	10,000	91.15 – 94.00	92.18	68.00	—	—
Oct – Dec	LLS	8,000	93.80 – 96.50	94.94	68.00	—	—
2015 Collars							
Jan – Mar	NYMEX	24,000	$ 80.00 – 100.90	$ —	$ —	$ 80.00	$ 96.75
Jan – Mar	LLS	4,000	85.00 – 102.20	—	—	85.00	102.10
Apr – June	NYMEX	30,000	80.00 – 95.25	—	—	80.00	94.72
Apr – June	LLS	4,000	85.00 – 102.50	—	—	85.00	101.75
July – Sept	NYMEX	28,000	80.00 – 95.25	—	—	80.00	95.05
July – Sept	LLS	4,000	85.00 – 100.00	—	—	85.00	99.50
2015 Three-Way Collars (5)							
Oct – Dec	NYMEX	8,000	$ 85.00 – 102.00	$ —	$ 68.00	$ 85.00	$ 98.50
Oct – Dec	LLS	8,000	88.00 – 104.25	—	68.00	88.00	100.99
2016 Enhanced Swaps (4)							
Jan – Mar	NYMEX	6,000	$ 92.65 – 92.65	$ 92.65	$ 68.00	$ —	$ —
Jan – Mar	LLS	6,000	94.85 – 95.45	95.18	68.00	—	—
2016 Three-Way Collars							
Jan – Mar	NYMEX	6,000	$ 85.00 – 99.50	$ —	$ 68.00	$ 85.00	$ 99.50
Jan – Mar	LLS	4,000	88.00 – 102.00	—	68.00	88.00	101.58
Natural Gas Contracts:							
2014 Collars							
July – Dec	NYMEX	14,000	$ 4.00 – 4.47	$ —	$ —	$ 4.00	$ 4.45
2015 Collars							
Jan – Dec	NYMEX	8,000	$ 4.00 – 4.53	$ —	$ —	$ 4.00	$ 4.51

(1) Contract prices are stated in \$/Bbl and \$/MMBtu for oil and natural gas contracts, respectively.
(2) Contract volumes are stated in Bbls/d and MMBtus/d for oil and natural gas contracts, respectively.
(3) Ranges presented for fixed-price swaps and enhanced swaps represent the lowest and highest fixed prices of all open contracts for the period presented. For collars and three-way collars, ranges represent the lowest floor price and highest ceiling price for all open contracts for the period presented.

(4) An enhanced swap is a fixed-price swap contract combined with a sold put feature (at a lower price) with the same counterparty. The value associated with the sold put is used to increase or enhance the fixed price of the swap. At the contract settlement date, (1) if the index price is higher than the swap price, we pay the counterparty the difference between the index price and swap price for the contracted volumes, (2) if the index price is lower than the swap price but at or above the sold put price, the counterparty pays us the difference between the index price and the swap price for the contracted volumes, and (3) if the index price is lower than the sold put price, the counterparty pays us the difference between the swap price and the sold put price for the contracted volumes.

(5) A three-way collar is a costless collar contract combined with a sold put feature (at a lower price) with the same counterparty. The value received for the sold put is used to enhance the contracted floor and ceiling price of the related collar. At the contract settlement date, (1) if the index price is higher than the ceiling price, we pay the counterparty the difference between the index price and ceiling price for the contracted volumes, (2) if the index price is between the floor and ceiling price, no settlements occur, (3) if the index price is lower than the floor price but at or above the sold put price, the counterparty pays us the difference between the index price and the floor price for the contracted volumes, and (4) if the index price is lower than the sold put price, the counterparty pays us the difference between the floor price and the sold put price for the contracted volumes.

Note 6. Fair Value Measurements

The FASC *Fair Value Measurements and Disclosures* topic defines fair value as the price that would be received to sell an asset or would be paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize 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 endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We are able to classify fair value balances based on the observability of those inputs. The FASC establishes a fair value 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 the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

- Level 1 – Quoted prices in active markets for identical assets or liabilities as of the reporting date.

- 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 reported date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. Instruments in this category include non-exchange-traded oil and natural gas derivatives that are based on NYMEX pricing. Our fixed-price swap contracts are valued using a discounted cash flow model based upon forward commodity price curves. Our costless collars and the written put features of our enhanced oil swaps and three-way collars are valued using the Black-Scholes model, an industry standard option valuation model, that takes into account inputs such as contractual prices for the underlying instruments, including maturity, quoted forward prices for commodities, interest rates, volatility factors and credit worthiness, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

- 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 June 30, 2014, instruments in this category include non-exchange-traded oil derivatives that are based on regional pricing other than NYMEX. The valuation models utilized for enhanced swaps, costless collars and three-way collars are consistent with the methodologies described above; however, since the instruments are based on regional pricing other than NYMEX, the inputs to the valuation are less observable from objective sources. Implied volatilities utilized in the valuation of Level 3 instruments are developed using a benchmark, which is considered a significant unobservable input. A one percent increase or decrease in implied volatility would result in a change of approximately $0.1 million in the fair value of these instruments as of June 30, 2014.

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We adjust the valuations from the valuation model for nonperformance risk, using our estimate of the counterparty's credit quality for asset positions and our credit quality for liability positions. We use multiple sources of third-party credit data in determining counterparty nonperformance risk, including credit default swaps.

The following table sets forth, by level within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of the periods indicated:

	Fair Value Measurements Using:			
In thousands	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
June 30, 2014				
Assets:				
Oil and natural gas derivative contracts – long-term	$ —	$ 94	$ —	$ 94
Total Assets	$ —	$ 94	$ —	$ 94
Liabilities:				
Oil and natural gas derivative contracts – current	$ —	$ (159,707)	$ (25,747)	$ (185,454)
Oil and natural gas derivative contracts – long-term	—	(22,658)	(13,369)	(36,027)
Total Liabilities	$ —	$ (182,365)	$ (39,116)	$ (221,481)
December 31, 2013				
Assets:				
Oil and natural gas derivative contracts – current	$ —	$ 5	$ —	$ 5
Oil and natural gas derivative contracts – long-term	—	3,034	6,908	9,942
Total Assets	$ —	$ 3,039	$ 6,908	$ 9,947
Liabilities:				
Oil and natural gas derivative contracts – current	$ —	$ (53,822)	$ —	$ (53,822)
Oil and natural gas derivative contracts – long-term	—	(3,214)	(199)	(3,413)
Total Liabilities	$ —	$ (57,036)	$ (199)	$ (57,235)

Since we do not use hedge accounting for our commodity derivative contracts, any gains and losses on our assets and liabilities are included in "Commodity derivatives expense (income)" in our Unaudited Condensed Consolidated Statements of Operations.

Level 3 Fair Value Measurements

The following table summarizes the changes in the fair value of our Level 3 assets and liabilities for the three and six months ended June 30, 2014 and 2013:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands	2014	2013	2014	2013
Fair value of Level 3 instruments, beginning of period	$ (6,097)	$ —	$ 6,709	$ —
Fair value adjustments on commodity derivatives	(33,019)	3,096	(45,825)	3,096
Fair value of Level 3 instruments, end of period	$ (39,116)	$ 3,096	$ (39,116)	$ 3,096
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets or liabilities still held at the reporting date	$ (33,019)	$ 3,096	$ (45,825)	$ 3,096

We utilize an income approach to value our Level 3 enhanced swaps, costless collars and three-way collars. We obtain and ensure the appropriateness of the significant inputs to the calculations, including contractual prices for the underlying instruments, maturity, forward prices for commodities, interest rates, volatility factors and credit worthiness, and the fair value estimate is prepared and reviewed on a quarterly basis. The following table details fair value inputs related to implied volatilities utilized in the valuation of our Level 3 oil derivative contracts:

	Fair Value at 6/30/2014 (in thousands)	Valuation Technique	Unobservable Input	Range
Oil derivative contracts	$ (39,116)	Discounted cash flow	Volatility of Light Louisiana Sweet index for settlement periods beginning after January 1, 2015	13.6% – 19.7%

Other Fair Value Measurements

The carrying value of our Bank Credit Facility approximates fair value, as it is subject to short-term floating interest rates that approximate the rates available to us for those periods. We use a market approach to determine fair value of our fixed-rate debt using observable market data. The fair values of our senior subordinated notes are based on quoted market prices. The estimated fair value of our total long-term debt as of June 30, 2014 and December 31, 2013, excluding pipeline financing and capital lease obligations, was $3,317.4 million and $2,956.8 million, respectively. We have other financial instruments consisting primarily of cash, cash equivalents, short-term receivables and payables that approximate fair value due to the nature of the instrument and the relatively short maturities.

Note 7. Commitments and Contingencies

We are involved in various lawsuits, claims and other regulatory proceedings incidental to our businesses. While we currently believe that the ultimate outcome of these proceedings, individually and in the aggregate, will not have a material adverse effect on our financial position, results of operations or cash flows, litigation is subject to inherent uncertainties. If an unfavorable ruling were to occur, there exists the possibility of a material adverse impact on our net income in the period in which the ruling occurs. We provide accruals for litigation and claims if we determine that a loss is probable and the amount can be reasonably estimated. We are also subject to audits for sales and use taxes and severance taxes in the various states in which we operate, and from time to time receive assessments for potential taxes that we may owe.

Delhi Field Release

In June 2013, a release of well fluids, consisting of a mixture of carbon dioxide, saltwater, natural gas and oil, was discovered (and reported) within an area of the Denbury-operated Delhi Field located in northern Louisiana. We completed our remediation efforts with respect to such release during the fourth quarter of 2013; however, we continue to monitor the impacted area to confirm the effectiveness of the remediation efforts. We have incurred $110.9 million of the total cost estimate of $114 million, which total cost estimate was expensed in lease operating expenses in 2013. In addition, a few third-party property and commercial damage claims have been asserted recently in connection with the release; however, due to the current lack of quantifiable information relative to these claims, a range of potential costs associated with the asserted claims cannot be reasonably estimated at this time and, accordingly, the total cost estimate of $114 million has not been adjusted. Although we maintain insurance policies that we believe cover certain of the costs, damages and claims related to the release, and we currently estimate that one-third to two-thirds of our total estimated costs of $114 million may be recoverable under such insurance policies, we have not reached any agreement with our insurance carriers as to recoverable amounts, and accordingly have not recognized any insurance recoveries in our financial statements to date. Any future insurance recoveries will be recognized in our financial statements during the period received or at the time such receipt and the amount thereof is determined to be virtually certain.

Note 8. Subsequent Event

Dividend Declaration

On July 29, 2014, the Board of Directors declared a dividend of $0.0625 per share on our common stock, payable on September 30, 2014, to stockholders of record at the close of business on August 26, 2014.

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

The following discussion and analysis should be read in conjunction with our Unaudited Condensed Consolidated Financial Statements and Notes thereto included herein and our Consolidated Financial Statements and Notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2013 (the "Form 10-K"), along with *Management's Discussion and Analysis of Financial Condition and Results of Operations* contained in the Form 10-K. Any terms used but not defined herein have the same meaning given to them in the Form 10-K. Our discussion and analysis includes forward-looking information that involves risks and uncertainties and should be read in conjunction with *Risk Factors* under Item 1A of Part II of this report, along with *Forward-Looking Information* at the end of this section for information on the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

OVERVIEW

Denbury is a growing, dividend-paying, domestic oil and natural gas company. Our primary focus is on enhanced oil recovery utilizing CO_2, and our operations are focused in two key operating areas: the Gulf Coast and Rocky Mountain regions. Our goal is to increase the value of acquired properties through a combination of exploitation, drilling and proven engineering extraction practices, with the most significant emphasis relating to tertiary recovery operations.

Operating Highlights. We recognized a net loss of $55.2 million, or $0.16 per basic common share, during the second quarter of 2014, principally due to (i) a $174.8 million charge for commodity derivatives expense ($124.6 million of which represents a noncash fair value adjustment) and (ii) a $113.9 million loss on early extinguishment of debt due to the repurchase or redemption of our $996.3 million of 8¼% Senior Subordinated Notes due 2020 (the "8¼% Notes").

This net loss in the most recent quarter compares to net income of $130.0 million, or $0.35 per basic common share in the second quarter of 2013, with the difference primarily due to the same factors discussed above, with an increase of $220.3 million ($136.6 million after tax) in commodity derivatives expense between the two periods, $170.1 million of which relates to a change in the noncash fair value adjustments on our commodity derivatives and the same $113.9 million ($70.6 million after tax) loss on the early extinguishment of debt in the current year quarter related to the repurchase or redemption of our 8¼% Notes (see *April 2014 Debt Refinancing* below). The impact of these higher expenses in the 2014 period was partially offset by the charge of $70 million in the 2013 period for remediation costs for an area of Delhi Field, whereas no such amounts were recorded during the current-year quarter.

During the second quarter of 2014, our oil and natural gas production, which was 94% oil, averaged 75,320 BOE/d compared to 74,052 BOE/d produced during the second quarter of 2013. This 2% increase in production is attributable to a 6% increase in our tertiary oil production, to a Company quarterly record of 40,897 Bbls/d, offset by a 2% decline in production from our non-tertiary properties. See *Results of Operations – Production* for more information.

Our average realized oil price per barrel during the second quarter of 2014, excluding the impact of commodity derivative contracts, increased to $100.04 per Bbl compared to $98.92 per Bbl realized during the second quarter of 2013, and up from the $97.69 per Bbl average realized price in the first quarter of 2014. The actual oil price we realized relative to NYMEX oil prices (our NYMEX oil price differential) declined to $3.03 per Bbl below NYMEX prices in the second quarter of 2014, compared to a positive $4.78 per Bbl NYMEX differential in the second quarter of 2013, and a negative $0.91 NYMEX differential in the first quarter of 2014. This decline in our oil price differential was driven by a deterioration in the Light Louisiana Sweet index and Rocky Mountain region differentials relative to NYMEX oil prices. See *Results of Operations – Oil and Natural Gas Revenues* below for more information on our oil prices received and differentials to NYMEX prices.

To provide greater certainty to the range of our anticipated operating cash flows as we have transitioned to a dividend-paying entity, in late 2013 we entered into more fixed-price swaps in 2014 than we have historically. As a result of rising oil prices throughout the period, we paid $49.9 million on our fixed-price swap contracts that settled during the second quarter of 2014, lowering our realized oil price noted above by $7.72 per Bbl. Based on current futures prices as of August 4, 2014, and the fixed price swaps that we have in place for the remainder of 2014, we currently expect that we will continue to make payments on the settlements of these contracts, the amount of which is dependent upon fluctuations in future NYMEX prices in relation to the fixed prices of these swaps, which have a weighted average price of $92.52 per Bbl for the third and fourth quarters of 2014 (see Note

5, *Commodity Derivative Contracts*, to the Unaudited Condensed Consolidated Financial Statements for further details regarding the prices and volumes of our commodity derivative contracts and *Results of Operations – Commodity Derivative Contracts* for further discussion).

In recent years, and particularly during 2013, we have experienced gradually rising costs. As a result, one of our primary focuses in 2014 is to reduce costs throughout the organization, and we have a number of internal initiatives underway focused on this objective. Our cost reduction initiatives have identified many cost-saving opportunities that we expect will reduce expenses in future periods and some of which are starting to show up in our results. For example, on a sequential-quarterly basis, our production increased 2% organically and our lease operating expense per BOE decreased 7%. Our goal is to further reduce both capital project costs and per-barrel operating costs in 2014 and in the future.

April 2014 Debt Refinancing. On April 30, 2014, we issued $1.25 billion of 5½% Senior Subordinated Notes due 2022 (the "5½% Notes"). The net proceeds of $1.23 billion were used to repurchase and redeem our outstanding 8¼% Notes, which were issued in 2010, and to pay down approximately $150 million of outstanding borrowings on our bank credit facility. Also on April 30, 2014, we (1) completed a cash tender offer for our 8¼% Notes in which we purchased a total of $815.2 million principal amount of these notes; and (2) issued a notice of redemption and fully funded the redemption of all of the remaining outstanding 8¼% Notes ($181.1 million principal amount) at a price paid by the Trustee on the May 30, 2014 redemption date equal to 100% of their principal amount plus the required make-whole premium and accrued interest up to the redemption date. This refinancing reduces our interest on a principal balance equal to that of the 8¼% Notes by over $27 million per year; however, after factoring in the incremental subordinated debt we issued and the higher interest rate on subordinated debt versus bank debt, our net annual interest savings are estimated at approximately $17 million. Due to the refinancing, we recognized a loss on extinguishment of debt of $113.9 million (principally related to the tender or redemption premium on the 8¼% Notes repurchased) during the second quarter of 2014.

CAPITAL RESOURCES AND LIQUIDITY

Overview. Our primary sources of capital and liquidity are our cash flows from operations and borrowings under our bank credit facility. Our business is capital intensive, and it is common for oil and natural gas companies our size to reinvest most or all of their cash flow into developing new assets. We generally attempt to balance our capital expenditures and dividends with cash flows from operations. During the six months ended June 30, 2014, we spent a combined $541.2 million on capital expenditures and dividends while generating $544.7 million of cash flows from operations.

We project that we will have more than adequate capital resources and liquidity for the foreseeable future because (1) we have significant borrowing capacity on our bank line; (2) we have oil hedges in place for a significant portion of our forecasted proven oil production through the first quarter of 2016 (see Note 5, *Commodity Derivative Contracts*, to the Unaudited Condensed Consolidated Financial Statements for further details regarding the prices and volumes of our commodity derivative contracts); (3) we plan to fund both our projected capital expenditures and dividends with cash flow from operations, which means that our expected growth in production and cash flow will gradually reduce our leverage (assuming oil prices are relatively consistent with current levels); (4) we can significantly reduce our capital expenditures for extended periods of time if necessary, due to lower cash flows or share repurchases, and still maintain current production levels as a result of our unique EOR operations; and (5) the maturity dates of all but a minor amount of our senior subordinated notes extend eight years or more, including the new 5½% Notes issued in connection with the April 2014 debt refinancing (discussed above), and carry attractive fixed interest rates ranging between 4⅝% and 6⅜%.

2014 Capital Spending. We anticipate that our full-year 2014 capital budget, excluding any acquisitions, will be $1.0 billion, plus approximately $100 million in capitalized internal acquisition, exploration and development costs; capitalized interest; and pre-production startup costs associated with new tertiary floods. This combined 2014 capital expenditure amount of $1.1 billion, excluding acquisitions, is a reduction of $25 million from the previously disclosed amount of $1.125 billion due to a decrease in estimated capitalized interest and pre-production startup costs associated with new tertiary floods, and is comprised of the following:

- $680 million allocated for tertiary oil field expenditures;
- $220 million allocated for other areas, primarily non-tertiary oil field expenditures;
- $60 million for pipeline construction;

- $40 million to be spent on CO_2 sources; and
- $100 million for other capital items such as capitalized internal acquisition, exploration and development costs; capitalized interest; and pre-production startup costs associated with new tertiary floods.

During the six months ended June 30, 2014, we incurred capital expenditures of $497.7 million. See additional detail on our expenditures in the *Capital Expenditure Summary* below.

Based on oil and natural gas commodity futures prices in early August 2014, our current production forecast, and our fixed-price swaps covering a substantial portion of our anticipated 2014 production, we believe our anticipated 2014 cash flow from operations should be adequate to cover both our 2014 capital budget and planned 2014 dividend payments. If prices were to decrease or changes in operating results were to cause us to have a significant reduction in anticipated 2014 cash flows, we have ample availability on our bank credit facility to cover any potential shortfall, and we also have the ability to reduce our capital expenditures.

If we elect to reduce our capital spending due to lower cash flows or to fund share repurchases, any sizable reduction could lower our anticipated production levels in future years. For 2014 and some future years, we have contracted for certain capital expenditures; therefore, we cannot eliminate all of our capital commitments without penalties (refer to *Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Commitments and Obligations* in the Form 10-K).

Stock Repurchase Program. Our Board of Directors has approved a common share repurchase program for up to $1.162 billion of Denbury common stock. As of August 6, 2014, we had spent $940.0 million to repurchase 60.0 million shares of our common stock under this program (approximately 14.9% of our outstanding shares at September 30, 2011), leaving us with $221.9 million available for future purchases. Our most recent purchases under the plan occurred in February 2014, and during the first quarter of 2014, we repurchased $200.4 million of our common stock, primarily funded with incremental borrowings. Our share repurchases are based on various parameters including, but not limited to, the price of our common stock, oil prices, free cash flow, our leverage or other funding sources available to us. Therefore, future repurchases may be at a level less than the remaining approved balance under the program, for which there is no set expiration date. We anticipate that additional repurchases during 2014 will be primarily funded with excess cash flow from operations, with borrowings under our bank credit facility or a reduction in capital spending. See Note 4, *Stockholders' Equity*, to the Unaudited Condensed Consolidated Financial Statements for further discussion.

Dividends. In each of the first two quarters of 2014, we paid common stockholders a quarterly cash dividend of $0.0625 per common share, or aggregate dividends of $43.5 million. On July 29, 2014, our Board of Directors declared a dividend of $0.0625 per share on our common stock, a rate of $0.25 per share on an annualized basis, to stockholders of record at the close of business on August 26, 2014. We expect this dividend payment, which is to be paid on September 30, 2014, to be approximately $22 million. The declaration and payment of future dividends is at the discretion of our Board of Directors, and the amount thereof will depend on our results of operations, financial condition, capital requirements, level of indebtedness, and other factors deemed relevant by the Board of Directors. Based on our current financial projections and commodity price outlook, we expect to grow our annual dividend rate to between $0.50 per share and $0.60 per share in 2015 and at a sustainable rate thereafter.

Possible Insurance Recoveries to Cover Costs of 2013 Delhi Field Release. We completed our remediation efforts related to the release of well fluids at the Denbury-operated Delhi Field during the fourth quarter of 2013 and no additional remediation expense was recorded during the six months ended June 30, 2014. A few third-party property and commercial damage claims have been asserted recently in connection with the release; however, due to the current lack of quantifiable information relative to these claims, a range of potential costs associated with the asserted claims cannot be reasonably estimated at this time. Although we maintain insurance policies that we believe cover certain of the costs, damages and claims related to the release, and we currently estimate that one-third to two-thirds of our total estimated costs of $114 million may be recoverable under such insurance policies, we have not reached any agreement with our insurance carriers as to recoverable amounts, and accordingly have not recognized any insurance recoveries in our financial statements to date. Any future insurance recoveries will be recognized in our financial statements during the period received or at the time such receipt and the amount thereof is determined to be virtually certain. See Note 7, *Commitments and Contingencies* to the Unaudited Condensed Consolidated Financial Statements for further discussion.

Bank Credit Facility. We have a $1.6 billion bank credit facility that is secured by substantially all of our oil and natural gas properties. On April 15, 2014, we entered into a Twelfth Amendment to the underlying credit agreement to, among other modifications, increase the limit on the amount of Additional Permitted Subordinate Debt (as defined in the underlying bank credit agreement), as part of the April 2014 refinancing of our 8¼% Notes discussed above. As part of our semiannual bank review in May 2014, the borrowing base for our bank credit facility was reaffirmed at $1.6 billion. Our next borrowing base redetermination is scheduled on or around November 1, 2014. We currently do not anticipate any reduction in our borrowing base as part of that redetermination, and we believe, based on current commodity prices and our proved reserves, that we could obtain lender approval to significantly increase the borrowing base under our bank credit facility above the current $1.6 billion level if we desired to do so. As of June 30, 2014, we had availability of $1.1 billion with respect to such borrowing base, leaving us significant liquidity to fund capital expenditures and future dividends.

Capital Expenditure Summary. The following table of capital expenditures includes accrued capital for the six months ended June 30, 2014 and 2013:

	Six Months Ended June 30,	
In thousands	2014	2013
Capital expenditures by project		
Tertiary oil fields	$ 286,396	$ 307,133
Non-tertiary fields	122,981	100,229
Capitalized interest and internal costs (1)	45,702	57,525
Oil and natural gas capital expenditures	455,079	464,887
CO_2 pipelines	12,356	29,120
CO_2 sources (2)	28,237	67,144
CO_2 capitalized interest and other	2,052	24,726
Capital expenditures, before acquisitions	497,724	585,877
Property acquisitions (3)	—	1,067,559
Capital expenditures, total	$ 497,724	$ 1,653,436

(1) Includes capitalized internal acquisition, exploration and development costs; capitalized interest; and pre-production startup costs associated with new tertiary floods.
(2) Includes capital expenditures related to the Riley Ridge gas processing facility.
(3) Property acquisitions during the six months ended June 30, 2013 include capital expenditures of approximately $1.1 billion related to acquisitions during that period that are not reflected as an Investing Activity on our Unaudited Condensed Consolidated Statements of Cash Flows due to the movement of proceeds through a qualified intermediary to facilitate like-kind-exchange treatment under federal income tax rules.

For the first six months of 2014 and 2013, our capital expenditures, other than those for property acquisitions, were fully funded with cash flow from operations. For the first six months of 2013, property acquisitions were funded with proceeds from the 2012 Bakken exchange transaction.

Off-Balance Sheet Arrangements. Our off-balance sheet arrangements include operating leases for office space and various obligations for development and exploratory expenditures that arise from our normal capital expenditure program or from other transactions common to our industry, none of which are recorded on our balance sheet. In addition, in order to recover our undeveloped proved reserves, we must also fund the associated future development costs estimated in our proved reserve reports.

Our commitments and obligations consist of those detailed as of December 31, 2013 in our Form 10-K under *Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Commitments and Obligations*, together with those changes described in the *April 2014 Debt Refinancing* section above. See Note 7, *Commitments and Contingencies*, to the Unaudited Condensed Consolidated Financial Statements for further discussion.

RESULTS OF OPERATIONS

Our tertiary operations represent a significant portion of our overall operations and are our primary long-term strategic focus. The economics of a tertiary field and the related impact on our financial statements differ from a conventional oil and gas play, and we have outlined certain of these differences in our Form 10-K and other public disclosures. Our focus on these types of operations impacts certain trends in both current and long-term operating results. Please refer to *Management's Discussion and Analysis of Financial Condition and Results of Operations – Financial Overview of Tertiary Operations* in our Form 10-K for further information regarding these matters.

Operating Results Table

Certain of our operating results and statistics for the comparative three and six months ended June 30, 2014 and 2013 are included in the following table:

In thousands, except per share and unit data	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Operating results				
Net income (loss)	$ (55,200)	$ 129,980	$ 3,110	$ 217,551
Net income (loss) per common share – basic	(0.16)	0.35	0.01	0.59
Net income (loss) per common share – diluted	(0.16)	0.35	0.01	0.58
Net cash provided by operating activities	329,847	437,568	544,705	706,744
Average daily production volumes				
Bbls/d	71,051	69,895	70,446	64,764
Mcf/d	25,614	24,945	24,463	25,210
BOE/d [(1)]	75,320	74,052	74,523	68,966
Operating revenues				
Oil sales	$ 646,799	$ 629,189	$ 1,260,779	$ 1,195,332
Natural gas sales	10,230	8,999	20,096	16,509
Total oil and natural gas sales	$ 657,029	$ 638,188	$ 1,280,875	$ 1,211,841
Commodity derivative contracts [(2)]				
Payment on settlements of commodity derivatives	$ (50,172)	$ —	$ (77,341)	$ —
Noncash fair value adjustments on commodity derivatives [(3)]	(124,599)	45,501	(174,099)	33,572
Commodity derivatives income (expense)	$ (174,771)	$ 45,501	$ (251,440)	$ 33,572
Unit prices – excluding impact of derivative settlements				
Oil price per Bbl	$ 100.04	$ 98.92	$ 98.88	$ 101.97
Natural gas price per Mcf	4.39	3.96	4.54	3.62
Unit prices – including impact of derivative settlements [(2)]				
Oil price per Bbl	$ 92.32	$ 98.92	$ 92.88	$ 101.97
Natural gas price per Mcf	4.27	3.96	4.34	3.62
Oil and natural gas operating expenses				
Lease operating expenses [(4)]	$ 163,250	$ 220,558	$ 333,629	$ 361,100
Marketing expenses, net of third-party purchases, and plant operating expenses	13,524	10,444	25,787	18,525
Production and ad valorem taxes	47,520	41,049	89,934	76,469
Oil and natural gas operating revenues and expenses per BOE				
Oil and natural gas revenues	$ 95.86	$ 94.70	$ 94.96	$ 97.08
Lease operating expenses [(4)]	23.82	32.73	24.73	28.93
Marketing expenses, net of third-party purchases, and plant operating expenses	1.97	1.55	1.91	1.47
Production and ad valorem taxes	6.93	6.09	6.67	6.13
CO_2 sources and helium – revenues and expenses				
CO_2 and helium sales and transportation fees	$ 11,822	$ 6,562	$ 22,583	$ 13,120
CO_2 and helium discovery and operating expenses [(5)]	(5,590)	(3,419)	(10,795)	(7,141)
CO_2 and helium revenue and expenses, net	$ 6,232	$ 3,143	$ 11,788	$ 5,979

(1) Barrel of oil equivalent using the ratio of one barrel of oil to six Mcf of natural gas ("BOE").

(2) See also *Item 3. Quantitative and Qualitative Disclosures about Market Risk* below for information concerning our derivative transactions.

(3) Noncash fair value adjustments on commodity derivatives is a non-GAAP measure and is different from "Commodity derivatives expense (income)" in the Unaudited Condensed Consolidated Statements of Operations in that the noncash fair value adjustments on commodity derivatives represents only the net change between periods of the fair market values of commodity derivative positions, and excludes the impact of settlements on commodity derivatives during the period, which were payments on settlements of $50.2 million and $77.3 million for the three and six months ended June 30, 2014, respectively. There were no such receipts or payments on settlements for the three and six months ended June 30, 2013. We believe that noncash fair value adjustments on commodity derivatives is a useful supplemental disclosure to "Commodity derivatives expense (income)" in order to differentiate noncash fair market value adjustments from settlements on commodity derivatives during the period. This supplemental disclosure is widely used within the industry and by securities analysts, banks and credit rating agencies in calculating EBITDA and in adjusting net income to present those measures on a comparative basis across companies, as well as to assess compliance with certain debt covenants. Noncash fair value adjustments on commodity derivatives is not a measure of financial or operating performance under GAAP, nor should it be considered in isolation or as a substitute for "Commodity derivatives expense (income)" in the Unaudited Condensed Consolidated Statements of Operations.

(4) If lease operating expenses recorded to remediate an area of Delhi Field (see *Capital Resources and Liquidity – Possible Insurance Recoveries to Cover Costs of 2013 Delhi Field Release* above) were excluded, lease operating expenses would have totaled $150.6 million and $291.1 million for the three and six months ended June 30, 2013, respectively, and lease operating expense per BOE would have averaged $22.34 and $23.32 for the three and six months ended June 30, 2013, respectively.

(5) Includes $0.5 million of exploratory costs during the three and six months ended June 30, 2013. We incurred no exploratory costs during the three and six months ended June 30, 2014.

Production

Average daily production by area for each of the four quarters of 2013 and for the first and second quarters of 2014 is shown below:

	Average Daily Production (BOE/d)					
Operating Area	First Quarter 2013	Second Quarter 2013	Third Quarter 2013	Fourth Quarter 2013	First Quarter 2014	Second Quarter 2014
Tertiary oil production						
Gulf Coast region						
Mature properties:						
Brookhaven	2,305	2,339	2,224	2,026	1,877	1,818
Eucutta	2,636	2,642	2,504	2,280	2,181	2,150
Mallalieu	2,116	2,157	2,042	1,886	1,837	1,839
Other mature properties (1)	7,800	7,233	6,761	6,287	6,283	6,156
Total mature properties	14,857	14,371	13,531	12,479	12,178	11,963
Delhi	5,827	5,479	4,517	4,793	4,708	4,543
Hastings	3,956	4,010	3,699	4,270	4,618	4,759
Heidelberg	3,943	4,149	4,553	5,206	5,325	5,609
Oyster Bayou	2,252	2,518	3,213	3,869	4,055	4,415
Tinsley	8,222	8,225	7,951	7,809	8,430	8,518
Total Gulf Coast region	39,057	38,752	37,464	38,426	39,314	39,807
Rocky Mountain region						
Bell Creek	—	—	49	177	578	1,090
Total Rocky Mountain region	—	—	49	177	578	1,090
Total tertiary oil production	39,057	38,752	37,513	38,603	39,892	40,897
Non-tertiary oil and gas production						
Gulf Coast region						
Mississippi	3,013	2,367	2,692	2,711	2,513	2,319
Texas	6,692	6,932	6,548	5,994	6,444	6,508
Other	1,153	1,108	1,087	1,041	1,031	1,049
Total Gulf Coast region	10,858	10,407	10,327	9,746	9,988	9,876
Rocky Mountain region						
Cedar Creek Anticline (2)	8,745	19,935	18,872	18,601	19,007	19,155
Other	5,163	4,958	4,819	4,516	4,831	5,392
Total Rocky Mountain region	13,908	24,893	23,691	23,117	23,838	24,547
Total non-tertiary production	24,766	35,300	34,018	32,863	33,826	34,423
Total production	63,823	74,052	71,531	71,466	73,718	75,320

(1) Other mature properties include Cranfield, Little Creek, Lockhart Crossing, Martinville, McComb and Soso fields.
(2) Beginning March 27, 2013, amounts include production from our purchase of additional interests in CCA on that date.

Total Production

Total production during the second quarter of 2014 averaged 75,320 BOE/d, an increase of 1,268 BOE/d (2%) compared to the second quarter of 2013 production levels and an increase of 1,602 BOE/d (2%) compared to first quarter of 2014 production levels. The change between the comparative second quarters was primarily a result of production increases from our tertiary oil fields, partially offset by normal declines in our non-tertiary production, and the change comparing the sequential quarters of 2014 was a result of tertiary production increases, plus increases in non-tertiary production in our Rocky Mountain region. On a year-to-date basis, total production increased 5,557 BOE/d (8%) between the first six months of 2013 and 2014, due primarily to the timing of the purchase of additional interests in CCA which closed in late March 2013. Our production during the three and six months ended June 30, 2014 was 94% and 95% oil, respectively, consistent with oil production of 94% during the three and six months ended June 30, 2013.

Tertiary Production

We achieved record quarterly tertiary production during the second quarter of 2014, with average production of 40,897 Bbls/d. Second quarter of 2014 tertiary production increased 2,145 Bbls/d (6%) compared to tertiary production levels in the same period in 2013 and increased 1,005 Bbls/d (3%) when comparing tertiary production between the first and second quarters of 2014. These year-over-year and sequential-quarter increases were primarily due to production growth in response to continued field development and expansion of facilities in the tertiary floods at Hastings, Heidelberg, Oyster Bayou and Tinsley fields, partially offset by normal declines in our mature tertiary fields. In addition, tertiary production at Bell Creek Field has increased each quarter since its first tertiary oil production during the third quarter of 2013, and we currently expect production at Bell Creek Field to continue to increase during the remainder of 2014. The level of the year-over-year increase in tertiary production was also impacted by the mid-2013 incident at Delhi Field, which is the primary reason for a 936 Bbls/d decline in Delhi's production between the second quarters of 2013 and 2014. We currently expect production levels at Delhi Field to remain relatively steady prior to an approximate 25% reversionary interest to the seller, the timing of which is dependent upon, among other things, the amount and timing of any potential future insurance proceeds being received and their application to the calculation of "total net cash flow", as defined in the Delhi Field purchase agreements, upon which the reversionary date is based, and upon oil prices, production, and production costs. We currently estimate the reversionary date will occur in the fourth quarter of 2014, which date could be accelerated by our receipt of insurance proceeds or delayed by our incurrence of additional costs. Our mature tertiary properties are generally on decline with an average annual decline of approximately 12% during 2013. Between the first and second quarters of 2014, production from our mature tertiary properties declined just under 2%, a slightly lower decline rate than last year as a result of continued optimization work at these mature properties.

Non-Tertiary Production

Production from our non-tertiary operations averaged 34,423 BOE/d during the second quarter of 2014, a decrease of 877 BOE/d (2%) compared to second quarter 2013 levels, primarily due to lower production at CCA, as well as anticipated production declines at various non-tertiary properties in Texas. Sequentially, production in the most recent quarter from our non-tertiary operations increased 597 BOE/d (2%) compared to first quarter 2014 levels, due primarily to increased production at non-tertiary properties in the Rocky Mountain region as a result of recently completed wells and field optimization projects. Natural gas production from Riley Ridge averaged 2,200 Mcf/d (367 BOE/d) during the second quarter of 2014, which was lower than anticipated due to unplanned downtime as a result of, among other things, design, equipment, machinery and mechanical well failures. Production from our other non-tertiary properties is generally on decline, and in some instances the decline is pronounced when non-tertiary wells are shut in as part of an initiation or expansion of our tertiary floods in a field or an area of a field.

Oil and Natural Gas Revenues

Our oil and natural gas revenues during the three and six months ended June 30, 2014 increased 3% and 6%, respectively, compared to these revenues for the same periods in 2013. The increase during the comparative three-month periods is related to increases in production and commodity prices, and the increase during the comparative six-month periods is related to an increase in production, partially offset by a decrease in commodity prices. The changes in revenues due to these factors, excluding any impact of our commodity derivative contracts, are reflected in the following table:

	Three Months Ended June 30, 2014 vs. 2013		Six Months Ended June 30, 2014 vs. 2013	
In thousands	Increase in Revenues	Percentage Increase in Revenues	Increase (Decrease) in Revenues	Percentage Increase (Decrease) in Revenues
Change in oil and natural gas revenues due to:				
Increase in production	$ 10,927	2%	$ 97,652	8 %
Increase (decrease) in commodity prices	7,914	1%	(28,618)	(2)%
Total increase in oil and natural gas revenues	$ 18,841	3%	$ 69,034	6 %

Excluding any impact of our commodity derivative contracts, our net realized commodity prices and NYMEX differentials were as follows during the first quarters, second quarters, and six months ended June 30, 2014 and 2013:

	Three Months Ended March 31,		Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013	2014	2013
Net realized prices:						
Oil price per Bbl	$ 97.69	$ 105.59	$ 100.04	$ 98.92	$ 98.88	$ 101.97
Natural gas price per Mcf	4.71	3.28	4.39	3.96	4.54	3.62
Price per BOE	94.03	99.87	95.86	94.70	94.96	97.08
NYMEX differentials:						
Oil per Bbl	$ (0.91)	$ 11.17	$ (3.03)	$ 4.78	$ (1.97)	$ 7.69
Natural gas per Mcf	(0.02)	(0.21)	(0.19)	(0.05)	(0.11)	(0.14)

As reflected in the table above, our average net realized oil price, excluding the impact of commodity derivative contracts, increased 1% during the second quarter of 2014 from the average price received during the second quarter of 2013. Company-wide oil price differentials in the second quarter of 2014 were $3.03 below NYMEX, compared to an average differential of $4.78 above NYMEX in the second quarter of 2013. During the second quarter of 2014, we sold approximately 43% of our crude oil at prices based on the Light Louisiana Sweet ("LLS") index price, approximately 23% at prices partially tied to the LLS index price, and the balance at prices based on various other indexes tied to NYMEX prices, primarily in the Rocky Mountain region. These percentages compare to sales of approximately 44% of our crude oil at prices based on the LLS index price and approximately 22% at prices partially tied to the LLS index price during the second quarter of 2013. The net oil differential we received was primarily impacted by positive differentials in the Gulf Coast region, offset by negative differentials in the Rocky Mountain region, each of which is discussed in further detail below.

Our average NYMEX oil differential in the Gulf Coast region was a positive $0.73 per Bbl and $10.64 per Bbl during the three months ended June 30, 2014 and 2013, respectively, and a positive $3.05 per Bbl during the three months ended March 31, 2014. These differentials were impacted significantly by the changes in prices received for our crude oil sold under LLS index prices relative to the change in NYMEX prices. This LLS-to-NYMEX differential declined from a positive $15.07 per Bbl average differential on a trade-month basis in the second quarter of 2013 to a positive $6.06 per Bbl in the first quarter of 2014 and a positive $2.90 per Bbl in the second quarter of 2014.

NYMEX oil differentials in the Rocky Mountain region averaged $10.54 per Bbl and $6.77 per Bbl below NYMEX during the three months ended June 30, 2014 and 2013, respectively, and $9.06 per Bbl below NYMEX during the three months ended March 31, 2014. Differentials in the Rocky Mountain region can move significantly over short periods of time due to refinery and transportation issues.

Prices received in a regional market fluctuate frequently and can differ from NYMEX pricing due to a variety of reasons, including supply and/or demand factors and location differentials. Although we have seen the LLS and Rocky Mountain differentials improve somewhat in 2014 compared to the levels in the fourth quarter of 2013, we do not expect the LLS-to-NYMEX differential in the Gulf Coast region to return to the more favorable levels seen over the last few years due to the oil transportation capacity in that region that has been added, which allows more oil production access to the LLS market.

Our natural gas NYMEX differentials are generally caused by movement in the NYMEX natural gas prices during the month, as most of our natural gas is sold on an index price that is set near the first of each month. While the percentage change in NYMEX natural gas differentials can be quite large, these differentials are very seldom more than a dollar above or below NYMEX prices.

Commodity Derivative Contracts

The following tables summarize the impact our oil and natural gas derivative contracts had on our operating results for the three and six months ended June 30, 2014 and 2013:

	Three Months Ended June 30,					
	2014	2013	2014	2013	2014	2013
In thousands	Crude Oil Derivative Contracts		Natural Gas Derivative Contracts		Total Commodity Derivative Contracts	
Payment on settlements of commodity derivatives	$ (49,895)	$ —	$ (277)	$ —	$ (50,172)	$ —
Noncash fair value adjustments on commodity derivatives (1)	(124,865)	45,501	266	—	(124,599)	45,501
Total	$ (174,760)	$ 45,501	$ (11)	$ —	$ (174,771)	$ 45,501

	Six Months Ended June 30,					
	2014	2013	2014	2013	2014	2013
In thousands	Crude Oil Derivative Contracts		Natural Gas Derivative Contracts		Total Commodity Derivative Contracts	
Payment on settlements of commodity derivatives	$ (76,454)	$ —	$ (887)	$ —	$ (77,341)	$ —
Noncash fair value adjustments on commodity derivatives (1)	(173,719)	33,572	(380)	—	(174,099)	33,572
Total	$ (250,173)	$ 33,572	$ (1,267)	$ —	$ (251,440)	$ 33,572

(1) Noncash fair value adjustments on commodity derivatives is a non-GAAP measure. See *Operating Results Table* above for a discussion of the reconciliation between noncash fair value adjustments on commodity derivatives to "Commodity derivatives expense (income)" in the Unaudited Condensed Consolidated Statements of Operations.

To provide greater certainty to the range of our anticipated operating cash flows as we have transitioned to a dividend-paying entity, we have entered into more fixed-price swaps in 2014 than we have historically. Prior to 2014, most of our derivative contracts were collars that had a floor and ceiling price that provided price protection at a lower level, but also a wider range of variability in operating cash flows than if we had used fixed-price swap contracts. In early 2014, our fixed-price swaps looked to be at or better than the futures prices for 2014, but as a result of rising oil prices throughout the period, we paid out $49.9 million and $76.5 million during the three and six months ended June 30, 2014, respectively. These settlements lowered our net realized oil price by $7.72 per Bbl and $6.00 per Bbl during the three and six months ended June 30, 2014, respectively. Based on current futures prices as of August 4, 2014, which average roughly $97.00 per Bbl for the remainder of 2014, and the fixed price swaps that we have in place, we currently expect that we will continue to make payments on the settlements of these contracts, the amount of which is dependent upon fluctuations in future NYMEX prices in relation to the fixed prices of these swaps, which have a weighted average price of $92.52 per Bbl for the third and fourth quarters of 2014. The details of our derivative commodity contracts are included in Note 5, *Commodity Derivative Contracts*, to the Unaudited Condensed Consolidated Financial Statements. Also, see Item 3, *Quantitative and Qualitative Disclosures about Market Risk* below for additional discussion on our commodity derivative contracts.

Changes in the estimated fair value of our oil and natural gas derivative contracts are caused primarily by changes in commodity futures prices and the expiration of contracts. Because we do not utilize hedge accounting for our commodity derivative contracts, the period-to-period change in the estimated fair value of these contracts, as outlined above, is recognized in our statements of operations. The detail of our outstanding commodity derivative contracts as of June 30, 2014 is included in Note 5, *Commodity Derivative Contracts*, to the Unaudited Condensed Consolidated Financial Statements.

Production Expenses

Lease Operating Expense

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per-BOE data	2014	2013	2014	2013
Lease operating expense				
Tertiary – excluding Delhi remediation	$ 98,869	$ 82,941	$ 196,568	$ 169,749
Tertiary – Delhi remediation	—	70,000	—	70,000
Non-tertiary	64,381	67,617	137,061	121,351
Total lease operating expense	$ 163,250	$ 220,558	$ 333,629	$ 361,100
Lease operating expense per BOE				
Tertiary – excluding Delhi remediation	$ 26.57	$ 23.52	$ 26.88	$ 24.11
Tertiary – Delhi remediation	—	19.85	—	9.94
Non-tertiary	20.55	21.05	22.19	22.30
Total lease operating expense per BOE	23.82	32.73	24.73	28.93

Total lease operating expense during the three and six months ended June 30, 2014 decreased from the comparable 2013 periods on an absolute-dollar and per-BOE basis primarily due to the $70.0 million charge for Delhi remediation in the 2013 periods (see *Capital Resources and Liquidity – Possible Insurance Recoveries to Cover Costs of 2013 Delhi Field Release* above), whereas no such amounts were recorded in the comparable 2014 periods. Excluding Delhi remediation costs, total lease operating expense increased $12.7 million and $42.5 million on an absolute-dollar basis and $1.48 and $1.41 on a per-BOE basis during the three and six months ended June 30, 2014, respectively, compared to the same periods in 2013. The increase during both periods includes higher power and CO_2 costs and costs associated with the expansion of our CO_2 floods, including our newest tertiary flood at Bell Creek Field. The increase on an absolute-dollar basis during the six-month period is driven by our acquisition of additional interests in CCA, which were acquired in late March of 2013, resulting in only approximately three months of CCA expenses in the first half of 2013. Sequentially, lease operating expense declined 4% on an absolute-dollar and 7% on a per-BOE basis between the first and second quarters of 2014 as we have seen many of our costs decline, with the decrease in workover costs the primary component of lease operating expense cost reduction.

Tertiary lease operating expense decreased 35% on an absolute-dollar basis and 39% on a per-BOE basis during the second quarter of 2014 compared to the second quarter of 2013, primarily due to the $70.0 million charge for Delhi remediation in the 2013 periods (see *Capital Resources and Liquidity – Possible Insurance Recoveries to Cover Costs of 2013 Delhi Field Release* above), whereas no such amounts were recorded in the comparable 2014 periods. Excluding Delhi remediation costs, tertiary lease operating expense increased $15.9 million and $26.8 million on an absolute-dollar basis and $3.05 and $2.77 on a per-BOE basis during the three and six months ended June 30, 2014, respectively, compared to the same periods in 2013. The increases in both periods are primarily attributable to additional costs associated with our newest flood at Bell Creek Field which had initial production and operating expense in the third quarter of 2013, as well as its production being low relative to operating costs because production is still ramping up, resulting in high per-BOE operating costs, which is typical when we start up a new tertiary flood. The increase during the comparative six-month periods is further impacted by a higher number of well workovers to repair well failures during the first quarter of 2014, and higher power costs due to higher rates and usage during the first half of 2014. When comparing sequential quarters, tertiary lease operating expense increased slightly (1%) between the first and second quarters of 2014.

Currently, our CO_2 expense comprises approximately one-fourth of our typical tertiary operating expenses, and for the CO_2 reserves we already own, consists of CO_2 production expenses, and for the CO_2 reserves we do not own, consists of our purchase of CO_2 from royalty and working interest owners and anthropogenic (man-made) sources. During the second quarter of 2014, approximately 64% of the CO_2 utilized in our CO_2 floods consisted of CO_2 owned by us and the remaining portion we purchased from third-party owners (primarily royalty owners). The price we pay others for CO_2 varies by source and is generally indexed to oil prices. When combining the production cost of the CO_2 we own with what we pay third parties for CO_2, our average cost of CO_2 during the second quarter of 2014 was approximately$0.42 per Mcf, including taxes paid on CO_2 production but excluding depreciation and amortization of capital expended at our CO_2 source fields, anthropogenic sources and CO_2 pipelines. This rate during the second quarter of 2014 was higher than the $0.35 per Mcf comparable measure during the first quarter of 2014 and the $0.34 per Mcf spent during the second quarter of 2013, with these fluctuations primarily due to fluctuations in pricing of our Rocky Mountain region CO_2 and changes in the oil price index. Including the cost of depreciation and amortization of capital expended at our CO_2 source fields and anthropogenic sources, but excluding depreciation of our CO_2 pipelines, our cost of CO_2 was $0.53 per Mcf and $0.42 per Mcf during the second quarters of 2014 and 2013, respectively.

Non-tertiary lease operating expenses decreased 5% on an absolute-dollar basis and 2% on a per-BOE basis between the three months ended June 30, 2013 and 2014, primarily due to a general decrease in most operating costs in the current quarter. Non-tertiary lease operating expenses increased 13% on an absolute-dollar basis and decreased slightly on a per-BOE basis between the six months ended June 30, 2013 and 2014, primarily due to our late-March 2013 purchase of additional interests in CCA, which caused an increase in costs, but which properties generally have a lower operating cost on a per-BOE basis than our other non-tertiary properties. On a sequential-quarter basis, our non-tertiary lease operating expenses decreased $8.3 million (11%) on an absolute-dollar basis and $3.32 (14%) on a per-BOE basis during the second quarter of 2014, as we have seen many of our costs decline, with the decrease in workover costs the primary component of lease operating expense cost reductions.

Taxes Other Than Income

Taxes other than income includes ad valorem, production and franchise taxes. Taxes other than income increased $5.9 million and $13.8 million during the three and six months ended June 30, 2014, respectively, compared to the same periods in 2013. The change in each period is generally aligned with fluctuations in oil and natural gas revenues. The increase during the six-month period is further impacted by the change in the mix of properties subject to production and ad valorem taxes primarily as a result of the CCA acquisition.

General and Administrative Expenses ("G&A")

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per-BOE data and employees	2014	2013	2014	2013
Gross cash compensation and administrative costs	$ 86,048	$ 80,511	$ 178,045	$ 164,518
Gross stock-based compensation	11,131	9,996	22,357	20,759
Operator labor and overhead recovery charges	(42,933)	(43,398)	(86,073)	(81,792)
Capitalized exploration and development costs	(15,294)	(13,727)	(31,684)	(28,214)
Net G&A expense	$ 38,952	$ 33,382	$ 82,645	$ 75,271
G&A per BOE:				
Net administrative costs	$ 4.49	$ 3.89	$ 4.96	$ 4.88
Net stock-based compensation	1.19	1.06	1.17	1.15
Net G&A expense	$ 5.68	$ 4.95	$ 6.13	$ 6.03
Employees as of June 30	1,563	1,544		

Gross cash compensation and administrative costs on an absolute-dollar basis increased $5.5 million (7%) and $13.5 million (8%) during the three and six months ended June 30, 2014, respectively, compared to the same periods in 2013. These increases were primarily due to higher compensation-related costs and the prior-year period including a $1.9 million insurance reimbursement.

Net G&A expense on a per-BOE basis increased 15% and 2% during the three and six months ended June 30, 2014, respectively, compared to levels in the same periods in 2013. The increase between the comparative three- and six-month periods was primarily due to higher compensation-related costs and the prior-year period including a $1.9 million insurance reimbursement, partially offset by an increase in capitalized exploration and development costs and an increase in production during 2014.

Our well operating agreements allow us, when we are the operator, to charge a well with a specified overhead rate during the drilling phase and also to charge a monthly fixed overhead rate for each producing well. In addition, salaries associated with field personnel are initially recorded as gross cash compensation and administrative costs and subsequently reclassified to lease operating expenses or capitalized to field development costs to the extent those individuals are dedicated to oil and gas production, exploration, and development activities. As a result of additional operated wells, increased compensation expense and an increase in the COPAS overhead rate, the amount we recovered as operator labor and overhead charges increased by 5% during the six months ended June 30, 2014 compared to the amounts recovered in the same period in 2013. Capitalized exploration and development costs increased between both comparative periods, primarily due to increased compensation costs subject to capitalization.

Interest and Financing Expenses

In thousands, except per-BOE data and interest rates	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Cash interest expense	$ 48,886	$ 50,478	$ 99,957	$ 104,480
Noncash interest expense	3,459	3,403	6,978	7,140
Less: capitalized interest	(5,795)	(23,279)	(11,551)	(44,984)
Interest expense, net	$ 46,550	$ 30,602	$ 95,384	$ 66,636
Interest expense, net per BOE	$ 6.79	$ 4.54	$ 7.07	$ 5.34
Average debt outstanding	$ 3,709,263	$ 3,271,282	$ 3,615,898	$ 3,250,401
Average interest rate (1)	5.3%	6.2%	5.5%	6.4%

(1) Includes commitment fees but excludes debt issue costs and amortization of discount or premium.

As reflected in the table above, our average interest rate was lower in both the three and six months ended June 30, 2014 than in the same periods in 2013. The lower rates in 2014 include the impact of our April 2014 long-term debt refinancing, whereby we issued $1.25 billion of 5½% Notes to replace our $996.3 million of 8¼% Notes. The lower rates in the 2014 periods further reflect our refinancing in February 2013 of certain senior subordinated notes which had interest rates of 9½% and 9¾% with our 4⅝% Senior Subordinated Notes due 2023. In conjunction with these two refinancing transactions, we estimate that we will save approximately $60 million annually in cash interest expense on the principal amount of the refinanced notes; however, our savings will be partially offset by the incremental principal amount of the newly issued senior subordinated notes, some of which was used to repay lower rate bank debt. Although our cash interest costs are lower, as a result of completing major projects on which we had been previously capitalizing interest, specifically the Riley Ridge gas processing facility, Greencore Pipeline and the tertiary flood at Bell Creek, our capitalized interest in the 2014 periods decreased significantly, contributing to an increase in net interest expense of $15.9 million (52%) and $28.7 million (43%) between the three and six months ended June 30, 2014, respectively, compared to the same periods in 2013.

Depletion, Depreciation and Amortization ("DD&A")

In thousands, except per-BOE data	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Depletion and depreciation of oil and natural gas properties	$ 115,458	$ 99,927	$ 223,617	$ 185,106
Depletion and depreciation of CO_2 properties	7,342	6,932	15,300	14,269
Asset retirement obligations	2,197	2,116	4,398	4,220
Depreciation of pipelines, plants and other property and equipment	23,167	17,932	45,979	36,210
Total DD&A	$ 148,164	$ 126,907	$ 289,294	$ 239,805
DD&A per BOE:				
Oil and natural gas properties	$ 17.17	$ 15.14	$ 16.90	$ 15.16
CO_2, pipelines, plants and other property and equipment	4.45	3.68	4.55	4.04
Total DD&A cost per BOE	$ 21.62	$ 18.82	$ 21.45	$ 19.20

We adjust our DD&A rate each quarter for significant changes in our estimates of oil and natural gas reserves and costs. In addition, under full cost accounting rules, the divestiture of oil and gas properties generally does not result in gain or loss recognition; instead, the proceeds of the disposition reduce the full cost pool. As such, our DD&A rate has changed significantly over time, and it may continue to change in the future. Depletion and depreciation of oil and natural gas properties and asset retirement obligations increased 15% and 20% on an absolute-dollar basis for the three and six months ended June 30, 2014, respectively, compared to the same periods in 2013. The increase on an absolute-dollar basis was due to both higher production volumes and a higher depletion rate per BOE compared to the same periods in 2013. The DD&A rate per BOE for oil and natural gas properties increased 13% and 11% for the three and six months ended June 30, 2014, respectively, compared to levels in the same periods in 2013, primarily due to the recognition in late 2013 of proved reserves at Bell Creek Field and the related reclassification of costs from unevaluated to evaluated, and higher forecasted development costs.

Depletion and depreciation of our CO_2 properties, pipelines, plants, and other property and equipment increased 23% and 21% on an absolute-dollar and 21% and 13% on a per-BOE basis during the three and six months ended June 30, 2014, respectively, compared to the same periods in 2013, primarily due to the startup of the Riley Ridge gas processing facility in late 2013 and additional pipelines and CO_2 properties placed in service. The lower rate of increase on a per-BOE basis (compared to the absolute-dollar measure) was due to higher production volumes in the 2014 periods.

Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. We did not have a ceiling test write-down at June 30, 2014; however, if oil or natural gas prices were to decrease significantly in subsequent periods, we may be required to record write-downs under the full cost pool ceiling test in the future. The possibility and amount of any future write-down is difficult to predict, and will depend, in part, upon oil and natural gas prices, the incremental proved reserves that may be added each period, revisions to previous reserve estimates and future capital expenditures, as well as additional capital spent.

Income Taxes

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per-BOE amounts and tax rates	2014	2013	2014	2013
Current income tax expense (benefit)	$ (4,300)	$ (3,171)	$ 318	$ 7,348
Deferred income tax expense (benefit)	(28,564)	84,497	1,611	128,342
Total income tax expense (benefit)	$ (32,864)	$ 81,326	$ 1,929	$ 135,690
Average income tax expense (benefit) per BOE	$ (4.79)	$ 12.07	$ 0.14	$ 10.87
Effective tax rate	37.3%	38.5%	38.3%	38.4%

Our income taxes are based on estimated statutory rates of approximately 38% and 38.5% in 2014 and 2013, respectively. Our effective tax rate for the three months ended June 30, 2014 was slightly below our estimated statutory rate, primarily due to the utilization of the domestic production activities deduction. Our effective tax rate for the three months ended June 30, 2013 and the six months ended June 30, 2014 and 2013 was comparable to our estimated statutory rate. We recorded current income tax benefits for the three months ended June 30, 2014 and 2013 in recognition of an increase in our estimate of tax benefits expected to be received in both years. Current income taxes during the three months ended June 30, 2014 include tax benefits related to the loss on extinguishment of debt recognized during the period. During the six months ended June 30, 2014 and 2013, the amount recorded as current income tax expense represents our federal taxes reduced by enhanced oil recovery credits, plus our state income taxes.

As of June 30, 2014, we had an estimated $15.0 million of enhanced oil recovery credits to carry forward related to our tertiary operations, and $34.8 million of alternative minimum tax credits that can be utilized to reduce our current income taxes during 2014 or future years. These enhanced oil recovery credits do not begin to expire until 2025. Since the ability to earn additional enhanced oil recovery credits is based upon the level of oil prices, we would not currently expect to earn additional enhanced oil recovery credits unless oil prices were to significantly deteriorate.

Per-BOE Data

The following table summarizes our cash flow and results of operations on a per-BOE basis for the comparative periods. Each of the individual components is discussed above.

	Three Months Ended June 30,		Six Months Ended June 30,	
Per-BOE data	2014	2013	2014	2013
Oil and natural gas revenues	$ 95.86	$ 94.70	$ 94.96	$ 97.08
Payment on settlements of commodity derivatives	(7.32)	—	(5.73)	—
Lease operating expenses – excluding Delhi Field remediation	(23.82)	(22.34)	(24.73)	(23.32)
Lease operating expenses – Delhi Field remediation	—	(10.39)	—	(5.61)
Production and ad valorem taxes	(6.93)	(6.09)	(6.67)	(6.13)
Marketing expenses, net of third-party purchases, and plant operating expenses	(1.97)	(1.55)	(1.91)	(1.47)
Production netback	55.82	54.33	55.92	60.55
CO_2 and helium sales, net of operating and exploration expenses	0.90	0.46	0.87	0.48
General and administrative expenses	(5.68)	(4.95)	(6.13)	(6.03)
Interest expense, net	(6.79)	(4.54)	(7.07)	(5.34)
Other	1.58	0.54	1.10	0.39
Changes in assets and liabilities relating to operations	2.29	19.09	(4.31)	6.57
Cash flow from operations	48.12	64.93	40.38	56.62
DD&A	(21.62)	(18.82)	(21.45)	(19.20)
Deferred income taxes	4.17	(12.54)	(0.12)	(10.28)
Loss on early extinguishment of debt	(16.62)	(0.06)	(8.44)	(3.58)
Noncash fair value adjustments on commodity derivatives	(18.18)	6.75	(12.91)	2.69
Other noncash items	(3.92)	(20.97)	2.77	(8.82)
Net income (loss)	$ (8.05)	$ 19.29	$ 0.23	$ 17.43

CRITICAL ACCOUNTING POLICIES

For additional discussion of our critical accounting policies, which remain unchanged, see *Management's Discussion and Analysis of Financial Condition and Results of Operations* in our Form 10-K.

FORWARD-LOOKING INFORMATION

The statements contained in this Quarterly Report on Form 10-Q that are not historical facts, including, but not limited to, statements found in the section *Management's Discussion and Analysis of Financial Condition and Results of Operations*, are forward-looking statements, as that term is defined in Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), that involve a number of risks and uncertainties. Such forward-looking statements may be or may concern, among other things, forecasted production, cash flows and capital expenditures, levels of dividend payments in future periods, drilling activity or methods including the timing and location thereof, pending or planned acquisitions or dispositions, development activities, estimated timing of completion of pipeline construction and the cost thereof, timing of CO_2 injections and initial production responses thereto, cost savings, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO_2 reserves and their availability, helium reserves, potential reserves, percentages of recoverable original oil in place, hydrocarbon prices, pricing or cost assumptions based on current and projected oil and gas prices, cost and availability of equipment and services, liquidity, availability of capital, borrowing capacity, regulatory matters, prospective legislation affecting the oil and gas industry, mark-to-market values, competition, long-term forecasts of production, finding costs, rates of return, estimated costs, estimates of the range of potential insurance recoveries, estimates of costs of remedial activities, changes in costs, future capital expenditures and overall economics and other variables surrounding our operations and future plans. Such forward-looking statements generally are accompanied by words such as "plan," "estimate," "expect," "predict," "to our knowledge," "anticipate," "projected," "preliminary," "should," "assume," "believe," "may," or other words that convey, or are intended to convey, the uncertainty of future events or outcomes. Such forward-looking information is based upon management's current plans, expectations, estimates, and assumptions and is subject to a number of risks and uncertainties that could significantly and adversely affect current plans, anticipated actions, the timing of such actions and the Company's financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates or assumptions expressed in or implied by any forward-looking statements made by or on behalf of the Company. Among the factors that could cause actual results to differ materially are fluctuations in worldwide oil prices or in U.S. oil and/or natural gas prices and consequently in the prices received or demand for the Company's oil and natural gas; levels of future capital expenditures; effects of our indebtedness; success of our risk management techniques; inaccurate cost estimates; availability of and fluctuations in the prices of goods and services; the uncertainty of drilling results; operating hazards and remediation costs; disruption of operations and damages from well incidents, hurricanes, tropical storms, or forest fires; acquisition risks; requirements for capital or its availability; conditions in the worldwide financial and credit markets; general economic conditions; competition; government regulations, including tax and environmental; and unexpected delays, as well as the risks and uncertainties inherent in oil and gas drilling and production activities or that are otherwise discussed in this quarterly report, including, without limitation, the portions referenced above, and the uncertainties set forth from time to time in the Company's other public reports, filings and public statements including, without limitation, the Company's most recent Form 10-K.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Debt and Interest Rate Sensitivity

We finance some of our acquisitions and other expenditures with fixed and variable rate debt. These debt agreements expose us to market risk related to changes in interest rates. As of June 30, 2014, we had $445.0 million in outstanding borrowings on our bank credit facility. At this level of variable-rate debt, an increase or decrease of 10% in interest rates would have an immaterial effect on our interest expense. None of our existing debt has any triggers or covenants regarding our debt ratings with rating agencies, although under the NEJD financing lease, in the event of significant downgrades of our corporate credit rating by the rating agencies, certain credit enhancements can be required from us, and possibly other remedies made available under the lease.

The following table presents the principal balances of our debt, by maturity date, as of June 30, 2014:

In thousands	2014	2015	2016	2017	2021	2022	2023	Total
Variable rate debt:								
Bank Credit Facility (weighted average interest rate of 2.14% at June 30, 2014)	$ —	$ —	$ 445,000	$ —	$ —	$ —	$ —	$ 445,000
Fixed rate debt:								
6⅜% Senior Subordinated Notes due 2021	—	—	—	—	400,000	—	—	400,000
5½% Senior Subordinated Notes due 2022	—	—	—	—	—	1,250,000	—	1,250,000
4⅝% Senior Subordinated Notes due 2023	—	—	—	—	—	—	1,200,000	1,200,000
Other Subordinated Notes	—	484	—	2,250	—	—	—	2,734

See Note 3, *Long-Term Debt*, to the Unaudited Condensed Consolidated Financial Statements for details regarding our long-term debt, including information regarding our April 2014 debt issuance (at a lower interest rate and for a longer term) and repurchase or redemption of our outstanding 8¼% Senior Subordinated Notes due 2020.

Oil and Natural Gas Derivative Contracts

We have historically entered into oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production. We do not hold or issue derivative financial instruments for trading purposes. The production that we hedge has varied from year to year, depending on our levels of debt and financial strength and expectation of future commodity prices. To provide greater certainty to the range of our anticipated operating cash flows as we transitioned to a dividend-paying entity, in late 2013 we entered into more fixed-price swaps in 2014 than we have historically. Prior to 2014, most of our derivative contracts were collars that had a floor and ceiling price that provided price protection at a lower level, but also a wider range of variability in operating cash flows than if we had used fixed-price swap contracts. We anticipate that we may use more fixed-price swaps in the future or a combination of fixed-price swaps and collars as we look to provide more certainty around our cash flows in order to execute on our capital development plans, pay dividends and retain a healthy balance sheet. We may also look to hedge further out than the 18 months to two years than we have typically hedged, potentially up to three years, in order to provide greater certainty around oil and natural gas prices and projected cash flows for an extended period. See Notes 5 and 6 to the Unaudited Condensed Consolidated Financial Statements for additional information regarding our commodity derivative contracts.

All of the mark-to-market valuations used for our oil and natural gas derivatives are provided by external sources. We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures and diversification. All of our commodity derivative contracts are with parties that are lenders under our bank credit facility. We have included an estimate of nonperformance risk in the fair value measurement of our oil and natural gas derivative contracts, which we have measured for nonperformance risk based upon credit default swaps or credit spreads.

For accounting purposes, we do not apply hedge accounting to our oil and natural gas derivative contracts. This means that any changes in the fair value of these derivative contracts will be charged to earnings on a quarterly basis instead of charging the effective portion to other comprehensive income and the ineffective portion to earnings.

At June 30, 2014, our commodity derivative contracts were recorded at their fair value, which was a net liability of $221.4 million, a $174.1 million increase from the $47.3 million net liability recorded at December 31, 2013. This change is related to the expiration of commodity derivative contracts during 2014, new commodity derivative contracts we entered into during 2014 for future periods, and to the changes in oil and natural gas futures prices between December 31, 2013 and June 30, 2014.

Commodity Derivative Sensitivity Analysis

Based on NYMEX and LLS crude oil futures prices and natural gas futures prices as of June 30, 2014, and assuming both a 10% increase and decrease thereon, we would expect to make or receive payments on our crude oil and natural gas derivative contracts as shown in the following table:

	Receipt / (Payment)	
In thousands	Crude Oil Derivative Contracts	Natural Gas Derivative Contracts
Based on:		
Futures prices as of June 30, 2014	$ (217,095)	$ (230)
10% increase in prices	(575,954)	(1,955)
10% decrease in prices	68,895	152

Our commodity derivative contracts are used as an economic hedge of our exposure to commodity price risk associated with anticipated future production. As a result, changes in receipts or payments of our commodity derivative contracts due to changes in commodity prices as reflected in the above table would be mostly offset by a corresponding increase or decrease in the cash receipts on sales of our oil or natural gas production to which those commodity derivative contracts relate.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) was performed under the supervision and with the participation of the Company's management, including its Chief Executive Officer and Chief Financial Officer. Based on that evaluation, the Company's Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of June 30, 2014, to ensure that information required to be disclosed in the reports the Company files and submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that information that is required to be disclosed under the Exchange Act is accumulated and communicated to the Company's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

Evaluation of Changes in Internal Control over Financial Reporting. Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we have determined that, during the second quarter of fiscal 2014, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Information with respect to legal proceedings is incorporated by reference to the Form 10-K.

Item 1A. Risk Factors

Information with respect to the risk factors has been incorporated by reference to Item 1A of the Form 10-K. There have been no material changes to the risk factors since the filing of the Form 10-K.

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

Issuer Purchases of Equity Securities

The following table summarizes purchases of our common stock during the second quarter of 2014:

Month	Total Number of Shares Purchased [(1)]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (in millions) [(2)]
April 2014	7,937	$ 17.23	—	$ 221.9
May 2014	15,770	16.74	—	221.9
June 2014	29,942	17.95	—	221.9
Total	53,649		—	

(1) Stock repurchases during the second quarter of 2014 were made in connection with delivery by our employees of shares to us to satisfy their tax withholding requirements related to the vesting of restricted shares and the exercise of stock appreciation rights.

(2) In October 2011, our Board of Directors approved a common stock repurchase program for up to $500 million of Denbury's common stock, which was increased by an additional $271.2 million in November 2012, $140.7 million in November 2013, and $250.0 million in December 2013, for a total authorization under the program of $1.162 billion. The program has no pre-established ending date and may be suspended or discontinued at any time. We are not obligated to repurchase any dollar amount or specific number of shares of our common stock under the program.

Between early October 2011, when we announced the commencement of a common share repurchase program, and June 30, 2014, we repurchased 60.0 million shares of Denbury common stock (approximately 14.9% of our outstanding shares of common stock at September 30, 2011) for $940.0 million, or $15.68 per share.

Item 3. Defaults upon Senior Securities

None

Item 4. Mine Safety Disclosures

None

Item 5. Other Information

None

Item 6. Exhibits

Exhibit No.	Exhibit
4(a)	Indenture for 5½% Senior Subordinated Notes due 2022, dated as of April 30, 2014, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 of Form 8-K filed by the Company on May 1, 2014, File No. 001-12935).
4(b)	Third Supplemental Indenture for 8¼% Senior Subordinated Notes due 2020, dated as of April 30, 2014, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 of Form 8-K filed by the Company on May 1, 2014, File No. 001-12935).
31(a)*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b)*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101*	Interactive Data Files.

* Included herewith.

Denbury Resources Inc.

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.

	DENBURY RESOURCES INC.
August 7, 2014	/s/ Mark C. Allen
	Mark C. Allen Sr. Vice President and Chief Financial Officer
August 7, 2014	/s/ Alan Rhoades
	Alan Rhoades Vice President and Chief Accounting Officer

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INDEX TO EXHIBITS

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32	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101	Interactive Data Files.

Exhibit 31(a)

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Phil Rykhoek, certify that:

1. I have reviewed this report on Form 10-Q of Denbury Resources Inc. (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

August 7, 2014

/s/ Phil Rykhoek

Phil Rykhoek
President and Chief Executive Officer

Exhibit 31(b)

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark C. Allen, certify that:

1. I have reviewed this report on Form 10-Q of Denbury Resources Inc. (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

August 7, 2014

/s/ Mark Allen

Mark C. Allen

Senior Vice President, Chief Financial Officer,
Treasurer, and Assistant Secretary

Exhibit 32

Certification of Chief Executive Officer and Chief Financial Officer
Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the accompanying Annual Report on Form 10-Q for the quarter ended June 30, 2014 (the Report) of Denbury Resources Inc. (Denbury) as filed with the Securities and Exchange Commission, each of the undersigned, in his capacity as an officer of Denbury, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The Information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Denbury.

Dated: August 7, 2014	/s/ Phil Rykhoek
	Phil Rykhoek
	President and Chief Executive Officer
Dated: August 7, 2014	/s/ Mark C. Allen
	Mark C. Allen
	Senior Vice President, Chief Financial Officer, Treasurer, and Assistant Secretary