DENBURY RESOURCES INC
Form 10-Q
May 12, 2014

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

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

For the quarterly period ended March 31, 2014
OR

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

For the transition period from _______ to ________

Commission file number: 001-12935

DENBURY RESOURCES INC.
(Exact name of registrant as specified in its charter)

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

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

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

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

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

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 April 30, 2014
Common Stock, $.001 par value	351,684,797

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)

	March 31, 2014	December 31, 2013
Assets		
Current assets		
Cash and cash equivalents	$7,892	$12,187
Accrued production receivable	286,984	262,047
Trade and other receivables, net	72,664	78,295
Derivative assets	—	5
Deferred tax assets	45,264	52,754
Other current assets	10,780	9,271
Total current assets	423,584	414,559
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved properties	9,126,401	8,945,326
Unevaluated properties	801,314	780,481
CO_2 properties	1,126,579	1,117,167
Pipelines and plants	2,217,265	2,209,560
Other property and equipment	463,796	466,969
Less accumulated depletion, depreciation, amortization and impairment	(3,803,378)	(3,668,225)
Net property and equipment	9,931,977	9,851,278
Derivative assets	541	9,942
Goodwill	1,283,590	1,283,590
Other assets	228,266	229,368
Total assets	$11,867,958	$11,788,737
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$329,103	$410,543
Oil and gas production payable	178,593	174,677
Derivative liabilities	89,185	53,822
Current maturities of long-term debt	36,383	36,157
Total current liabilities	633,264	675,199
Long-term liabilities		
Long-term debt, net of current portion	3,512,041	3,260,625
Asset retirement obligations	116,524	119,888
Derivative liabilities	8,144	3,413
Deferred tax liabilities	2,422,004	2,399,294
Other liabilities	28,073	28,912
Total long-term liabilities	6,086,786	5,812,132
Commitments and contingencies (Note 7)		
Stockholders' equity		
Preferred stock, $.001 par value, 25,000,000 shares authorized, none issued and outstanding	—	—
	411	409

Common stock, $.001 par value, 600,000,000 shares authorized; 411,058,201 and 409,215,573 shares issued, respectively		
Paid-in capital in excess of par	3,199,379	3,186,714
Retained earnings	2,880,911	2,844,432
Accumulated other comprehensive loss	(261)	(276)
Treasury stock, at cost, 59,236,568 and 46,710,896 shares, respectively	(932,532)	(729,873)
Total stockholders' equity	5,147,908	5,301,406
Total liabilities and stockholders' equity	$11,867,958	$11,788,737

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Three Months Ended March 31,	
	2014	2013
Revenues and other income		
Oil, natural gas, and related product sales	$623,846	$573,653
CO_2 sales and transportation fees	10,761	6,558
Interest income and other income	7,137	2,875
Total revenues and other income	641,744	583,086
Expenses		
Lease operating expenses	170,379	140,542
Marketing and plant operating expenses	16,786	9,796
CO_2 discovery and operating expenses	5,205	3,722
Taxes other than income	45,945	38,011
General and administrative expenses	43,693	41,889
Interest, net of amounts capitalized of $5,756 and $21,705, respectively	48,834	36,034
Depletion, depreciation, and amortization	141,130	112,898
Commodity derivatives expense (income)	76,669	11,929
Loss on early extinguishment of debt	—	44,223
Other expenses	—	2,107
Total expenses	548,641	441,151
Income before income taxes	93,103	141,935
Income tax provision	34,793	54,364
Net income	$58,310	$87,571
Net income per common share		
Basic	$0.17	$0.24
Diluted	$0.17	$0.23
Dividends per common share	$0.0625	$—
Weighted average common shares outstanding		
Basic	350,747	369,396
Diluted	352,925	372,867

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Three Months Ended March 31,	
	2014	2013
Net income	$58,310	$87,571
Other comprehensive income, net of income tax:		
Interest rate lock derivative contracts reclassified to income, net of tax of $13, and $8, respectively	15	20
Total other comprehensive income	15	20
Comprehensive income	$58,325	$87,591

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Three Months Ended March 31,	
	2014	2013
Cash flow from operating activities		
Net income	$58,310	$87,571
Adjustments to reconcile net income to cash flow from operating activities		
Depletion, depreciation, and amortization	141,130	112,898
Deferred income taxes	30,175	43,845
Stock-based compensation	8,346	7,908
Commodity derivatives expense (income)	76,669	11,929
Settlements of commodity derivatives	(27,169)	—
Loss on early extinguishment of debt	—	44,223
Amortization of debt issuance costs and discounts	3,520	3,736
Other, net	(2,297)	3,636
Changes in assets and liabilities, net of effects from acquisitions:		
Accrued production receivable	(24,937)	344
Trade and other receivables	6,372	(13,815)
Other current and long-term assets	(5,459)	(4,756)
Accounts payable and accrued liabilities	(52,580)	(33,337)
Oil and natural gas production payable	3,916	12,424
Other liabilities	(1,138)	(7,430)
Net cash provided by operating activities	214,858	269,176
Cash flow used in investing activities		
Oil and natural gas capital expenditures	(198,237)	(226,917)
Acquisitions of oil and natural gas properties	—	(101)
CO_2 capital expenditures	(15,909)	(27,014)
Pipelines and plants capital expenditures	(22,597)	(50,416)
Purchases of other assets	(1,645)	(14,867)
Net proceeds from sales of oil and natural gas properties and equipment	457	663
Other	1,177	(1,994)
Net cash used in investing activities	(236,754)	(320,646)
Cash flow provided by financing activities		
Bank repayments	(815,000)	(820,000)
Bank borrowings	1,075,000	395,000
Repayment of senior subordinated notes	—	(613,064)
Premium paid on repayment of senior subordinated notes	—	(34,660)
Proceeds from issuance of senior subordinated notes	—	1,200,000
Costs of debt financing	—	(20,000)
Common stock repurchase program	(211,356)	(81,402)
Dividends paid	(21,727)	—
Other	(9,316)	(10,646)
Net cash provided by financing activities	17,601	15,228
Net decrease in cash and cash equivalents	(4,295)	(36,242)
Cash and cash equivalents at beginning of period	12,187	98,511
Cash and cash equivalents at end of period	$7,892	$62,269

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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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 March 31, 2014, our consolidated results of operations for the three months ended March 31, 2014 and 2013, and our consolidated cash flows for the three months ended March 31, 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 per Common Share

Basic net income per common share is computed by dividing the net income attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted net income 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 months ended March 31, 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

In thousands	March 31, 2014	2013
Basic weighted average common shares outstanding	350,747	369,396
Potentially dilutive securities:		
Restricted stock, stock options, SARs and performance-based equity awards	2,178	3,471
Diluted weighted average common shares outstanding	352,925	372,867

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, 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. Stock options and SARs of 4.3 million shares and 3.7 million shares were not included in the computation of diluted net income per share for the three months ended March 31, 2014 and 2013, respectively, as their effect would have been antidilutive.

Recent Accounting Pronouncements

Discontinued Operations. In April 2014, the Financial Accounting Standards Board issued Accounting Standards Update ("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 Financial Accounting Standards Board Codification and requires entities to disclose additional information about 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. In March 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 three months ended March 31, 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.

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	Three Months Ended March 31, 2013
Pro forma total revenues and other income	$665,260
Pro forma net income	117,775
Pro forma net income per common share	
Basic	$0.32
Diluted	0.32

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Note 3. Long-Term Debt

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

In thousands	March 31, 2014	December 31, 2013
Bank Credit Agreement	$600,000	$340,000
8¼% Senior Subordinated Notes due 2020	996,273	996,273
6 % Senior Subordinated Notes due 2021	400,000	400,000
4 % Senior Subordinated Notes due 2023	1,200,000	1,200,000
Other Subordinated Notes, including premium of $15 and $16, respectively	3,821	3,823
Pipeline financings	226,147	228,167
Capital lease obligations	122,183	128,519
Total	3,548,424	3,296,782
Less: current obligations	(36,383)	(36,157)
Long-term debt and capital lease obligations	$3,512,041	$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.

April 2014 Issuance of 5½% Senior Subordinated Notes due 2022 and Repurchase of 8¼% Senior Subordinated Notes due 2020

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 from the issuance of the 5½% Notes were used to repurchase or redeem our 8¼% Senior Subordinated Notes due 2020 (the "8¼% Notes") and to reduce borrowings under our Bank Credit Agreement (defined below). See Note 8, Subsequent Events, for more information.

$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. 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, with approval by all of the lenders. 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 March 31, 2014 under the Bank Credit Agreement was 1.91%. 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.

4 % Senior Subordinated Notes due 2023

In February 2013, we issued $1.2 billion of 4 % Senior Subordinated Notes due 2023 (the "4 % Notes"). The 4 % Notes, which carry a coupon rate of 4.625%, were sold at par. 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 Repurchase and Redemption of 9½% Notes and 9¾% Notes below) and to pay down a portion of outstanding borrowings under our Bank Credit Agreement.

Repurchase and Redemption of 9½% Notes and 9¾% Notes

Pursuant to cash tender offers, during the three months ended March 31, 2013, we repurchased $426.4 million principal amount of our 9¾% Notes and $186.7 million principal amount of our 9½% Notes. We recognized a loss associated with the debt repurchases of $44.2 million during the three months ended March 31, 2013, 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". We repurchased the remaining $38.2 million principal amount of our 9½% Notes in the second quarter of 2013.

Note 4. Stockholders' Equity

Dividends

On January 28, 2014, Denbury's Board of Directors declared a quarterly cash dividend of $0.0625 per common share to shareholders of record as of the close of business on February 25, 2014. The dividend in the amount of $21.7 million was paid on March 25, 2014. See Note 8, Subsequent Events, for dividends declared in the second 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 three months ended March 31, 2014. Since commencement of the share repurchase program in October 2011 through March 31, 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 March 31, 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, 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 March 31, 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.

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The following table summarizes our commodity derivative contracts, none of which are classified as hedging instruments:

Months	Pricing Index	Volume (2)	Contract Prices (1) Range (3)		Weighted Average Price Swap	Sold Put	Floor	Ceiling
Oil Contracts:								
2014 Fixed-Price Swaps								
Apr – June	NYMEX	58,000	$ 91.67	– 95.95	$93.53	$—	$—	$—
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	10,000	$ 90.00	– 90.30	$90.08	$65.30	$—	$—
Jan – Mar	LLS	16,000	93.20	– 94.00	93.63	68.00	—	—
Apr – June	NYMEX	4,000	90.00	– 90.00	90.00	66.50	—	—
Apr – June	LLS	16,000	93.20	– 94.00	93.65	68.00	—	—
July – Sept	NYMEX	4,000	90.00	– 90.10	90.05	65.75	—	—
July – Sept	LLS	16,000	93.20	– 94.00	93.65	68.00	—	—
2015 Collars								
Jan – Mar	NYMEX	28,000	$ 80.00	– 100.90	$—	$—	$80.00	$96.68
Jan – Mar	LLS	4,000	85.00	– 102.20	—	—	85.00	102.10
Apr – June	NYMEX	34,000	80.00	– 95.25	—	—	80.00	94.66
Apr – June	LLS	4,000	85.00	– 102.50	—	—	85.00	101.75
July – Sept	NYMEX	34,000	80.00	– 95.25	—	—	80.00	95.04
July – Sept	LLS	4,000	85.00	– 100.00	—	—	85.00	99.50
Natural Gas Contracts:								
2014 Collars								
Apr – 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 price of all open contracts for the period presented. For 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 received for 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.

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 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 March 31, 2014, instruments in this category include non-exchange-traded oil collars and enhanced oil swaps that are based on regional pricing other than NYMEX. The valuation models utilized for fixed-price swap, enhanced swap and costless 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. 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. 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 March 31, 2014.

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.

Denbury Resources Inc.
Notes to Unaudited Condensed Consolidated Financial Statements

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
March 31, 2014				
Assets:				
Oil and natural gas derivative contracts – current	$—	$—	$—	$—
Oil and natural gas derivative contracts – long-term	—	378	163	541
Total Assets	$—	$378	$163	$541
Liabilities:				
Oil and natural gas derivative contracts – current	$—	$(84,798)	$(4,387)	$(89,185)
Oil and natural gas derivative contracts – long-term	—	(6,271)	(1,873)	(8,144)
Total Liabilities	$—	$(91,069)	$(6,260)	$(97,329)
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.

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 March 31, 2014 and December 31, 2013, excluding pipeline financing and capital lease obligations, was $3,234.6 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

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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 during the fourth quarter of 2013; however, we continue to monitor the area to ensure the remediation efforts were successful. We have incurred $97.3 million of the total cost estimate of $114 million which was expensed in Lease Operating Expense in 2013. Due to the possibility of new claims being asserted in the future in connection with the release, as well as variability in the estimated cost to continue to monitor the area to ensure the remediation efforts were successful, we cannot reliably estimate at this time the full extent of the costs that may ultimately be incurred by the Company related to this release. Although the Company maintains insurance policies that we believe cover certain of the costs, damages and claims related to the release, and we currently and preliminarily estimate that one-third to two-thirds of our current cost estimate 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 receipt is determined to be virtually certain.

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Denbury Resources Inc.
Notes to Unaudited Condensed Consolidated Financial Statements

Note 8. Subsequent Events

New 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 of $1.23 billion were used to repurchase or redeem our outstanding 8¼% Notes and to reduce borrowings under our Bank Credit Agreement (see Tender Offer below).

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 4 % Notes and contains certain restrictions on our ability to: (1) incur additional debt; (2) pay dividends on our common stock or redeem, repurchase or retire such capital stock or subordinated debt unless certain leverage ratios are met; (3) make investments; (4) create liens on our assets; (5) create restrictions on the ability of our restricted subsidiaries to pay dividends or make other payments to the Company; (6) engage in transactions with our affiliates; (7) transfer or sell assets; and (8) consolidate, merge or transfer all or substantially all of our assets and the assets of our subsidiaries. All of our significant subsidiaries fully and unconditionally guarantee this debt.

Tender Offer and Repurchase 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 a price to be paid 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 but excluding the redemption date, resulting in a satisfaction and discharge of the indenture for the 8¼% Notes.

Dividend Declaration

On April 29, 2014, the Board of Directors declared a dividend of $0.0625 per share on our common stock, payable on June 24, 2014 to stockholders of record at the close of business on May 27, 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.

Comparison of First Quarter Year-to-Year Financial Results. At the end of the first quarter of 2013, we closed our acquisition of additional interests at Cedar Creek Anticline ("CCA"), increasing our production, oil and natural gas revenues and operating costs in subsequent periods, thus affecting most components of our comparisons of 2014 to 2013 first-quarter results. This acquisition was the primary reason for a 16% increase in quarterly production year over year. The higher production increased our oil and natural gas revenues, but lower realized oil and natural gas prices decreased oil and natural gas revenues by 7%, resulting in a net 9% increase in oil and natural gas revenues between the respective first quarters. Almost all of our costs increased during the first quarter of 2014 relative to the first quarter of 2013, with the most significant increases in lease operating expenses (21%), which primarily related to the acquisition of additional interests at CCA and costs of our newest tertiary flood at Bell Creek Field, and in depletion, depreciation and amortization (25%), which primarily related to increases in production from the CCA acquisition and increases late in 2013 to our depletable cost balance and higher finding and development costs resulting from the recognition of proved reserves at Bell Creek Field. Between the two quarters there were other factors that impacted net income, such as lower capitalized interest (which increased interest expense) and an increase in our commodity derivatives expenses, both in the first quarter of 2014, partially offset by the lack of debt extinguishment costs which we incurred in the first quarter of 2013. In summary, during the first quarter of 2014, our net income was $58.3 million, or $0.17 per diluted common share, less than net income of $87.6 million, or $0.23 per diluted common share, during the first quarter of 2013. These matters are further described throughout this Management's Discussion and Analysis of Financial Condition and Results of Operations.

In recent years, and particularly during 2013, the Company has 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. While almost all costs have increased on a year-over-year basis, 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. Our goal is to further reduce both capital project costs and per-barrel operating costs in 2014 and in the future.

Comparison of Sequential Quarterly Financial Results. On a sequential-quarterly basis, our production increased 3% organically and our lease operating expenses decreased 10%, but these gains were offset by a typical first quarter seasonal increase in general and administrative costs, lower capitalized interest resulting in higher interest expense, and a 37% effective tax rate compared to the unusually low 31% tax rate in the prior quarter results. Realized commodity prices increased between the two sequential periods, but the increase was almost totally offset by payments on our derivative contracts. Our cash interest costs were almost identical even though the expensed portion increased significantly (our capitalized interest decreased) as new projects came online. In general, our operating results improved slightly this quarter but net income was impacted significantly by a $49.5 million pre-tax noncash fair value adjustment on our derivatives. In summary, first quarter of 2014 net income of $58.3 million was less than fourth quarter of 2013 net income of $90.0 million. These matters are further described throughout this Management's Discussion and Analysis of Financial Condition and Results of Operations.

April 2014 Debt Refinancing. In April 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 or redeem our outstanding 8¼% Senior Subordinated Notes due 2020 (the "8¼% Notes"), and to pay down approximately $150 million of outstanding borrowings on our bank credit facility. On April 30, 2014, we (1) completed a cash tender offer for our 8¼% Notes; (2) purchased a total of $815.2 million principal amount of these notes; and (3) 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 to be 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 but excluding the redemption date. This refinancing reduces our interest on the principal balance 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 expect to recognize a loss on extinguishment of debt of approximately $115 million (principally related to the tender or redemption premium on the 8¼% Notes repurchased) during the second quarter of 2014. See Note 8, Subsequent Events, to the Unaudited Condensed Consolidated Financial Statements for additional details surrounding the 5½% Notes.

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 spending with cash flow from operations. We have repurchased 60.0 million shares of our common stock (approximately 14.9% of our outstanding shares at September 30, 2011) since commencement of our share repurchase program in October 2011 through May 6, 2014. During the three months ended March 31, 2014, we repurchased $200.4 million of our common stock, primarily funded with incremental borrowings. 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 third quarter of 2015, including fixed-price swap derivative contracts for 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); (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 notes issued in connection with the April 2014 notes refinancing (discussed above), and carry attractive fixed interest rates ranging between 4 % and 6 %.

2014 Capital Spending. We anticipate that our full-year 2014 capital budget, excluding any acquisitions, will be $1.0 billion, plus approximately $125 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 $1.125 billion, excluding acquisitions, 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
- $125 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 three months ended March 31, 2014, we incurred capital expenditures of approximately $220.6 million. See additional detail on our expenditures in the Capital Expenditure Summary below.

Based on oil and natural gas commodity futures prices in early May 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 May 6, 2014, we had spent $940.0 million to repurchase 60.0 million shares of our common stock under this program, leaving us with $221.9 million available for future purchases. 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.

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. 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 April 30, 2014, we had $450.0 million outstanding under our bank credit facility, leaving us significant liquidity to fund capital expenditures and future dividends.

Dividends. On March 25, 2014, we paid our first quarterly cash dividend of $0.0625 per common share ($21.7 million) to shareholders of record as of the close of business on February 25, 2014. On April 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 May 27, 2014. We expect this dividend payment to be approximately $22 million and to be paid on June 24, 2014. 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 Delhi Field during the fourth quarter of 2013 and no additional remediation expense has been recorded during the first quarter of 2014. Although the Company maintains insurance policies that we believe cover certain of the costs, damages and claims related to the release, and we currently and preliminarily estimate that one-third to two-thirds of our current estimate of incurred and projected remediation 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 receipt is determined to be virtually certain. See Note 7, Commitments and Contingencies to the Unaudited Condensed Consolidated Financial Statements for further discussion.

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Capital Expenditure Summary. The following table of capital expenditures includes accrued capital for the three months ended March 31, 2014 and 2013:

	Three Months Ended March 31,	
In thousands	2014	2013
Capital expenditures by project		
Tertiary oil fields	$123,901	$165,830
Non-tertiary fields	54,851	49,059
Capitalized interest and internal costs (1)	24,219	25,132
Oil and natural gas capital expenditures	202,971	240,021
CO_2 pipelines	3,244	11,688
CO_2 sources (2)	13,262	27,396
CO_2 capitalized interest and other	1,146	13,510
Capital expenditures, before acquisitions	220,623	292,615
Property acquisitions (3)	—	999,859
Capital expenditures, total	$220,623	$1,292,474

(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 three months ended March 31, 2013 include capital expenditures of approximately $1.0 billion related to our acquisition of additional interests in CCA 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 three months of 2014 and 2013, our capital expenditures, other than those for property acquisitions, were funded primarily with cash flow from operations. For the first three 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 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 have become 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.

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Operating Results Table

Certain of our operating results and statistics for the comparative first quarters of 2014 and 2013 are included in the following table:

	Three Months Ended March 31,	
In thousands, except per share and unit data	2014	2013
Operating results		
Net income	$58,310	$87,571
Net income per common share – basic	0.17	0.24
Net income per common share – diluted	0.17	0.23
Net cash provided by operating activities	214,858	269,176
Average daily production volumes		
Bbls/d	69,834	59,577
Mcf/d	23,299	25,477
BOE/d [(1)]	73,718	63,823
Operating revenues		
Oil sales	$613,980	$566,143
Natural gas sales	9,866	7,510
Total oil and natural gas sales	$623,846	$573,653
Commodity derivative contracts [(2)]		
Payment on settlements of commodity derivatives	$(27,169)	$—
Noncash fair value adjustments on commodity derivatives [(3)]	(49,500)	(11,929)
Commodity derivatives income (expense)	$(76,669)	$(11,929)
Unit prices – excluding impact of derivative settlements		
Oil price per Bbl	$97.69	$105.59
Natural gas price per Mcf	4.71	3.28
Unit prices – including impact of derivative settlements [(2)]		
Oil price per Bbl	$93.46	$105.59
Natural gas price per Mcf	4.41	3.28
Oil and natural gas operating expenses		
Lease operating expenses	$170,379	$140,542
Marketing expenses, net of third-party purchases, and plant operating expenses	12,263	8,081
Production and ad valorem taxes	42,414	35,420
Oil and natural gas operating revenues and expenses per BOE		
Oil and natural gas revenues	$94.03	$99.87
Lease operating expenses	25.68	24.47
Marketing expenses, net of third-party purchases, and plant operating expenses	1.84	1.41
Production and ad valorem taxes	6.39	6.17
CO_2 sources – revenues and expenses		
CO_2 sales and transportation fees	$10,761	$6,558
CO_2 discovery and operating expenses	(5,205)	(3,722)
CO_2 revenue and expenses, net	$5,556	$2,836

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

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(2) See also Item 3. Quantitative and Qualitative Disclosures about Market Risk below for information concerning the Company's 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 $27.2 million for the three months ended March 31, 2014. There were no such receipts or payments on settlements for the three months ended March 31, 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.

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Production

Average daily production by area for each of the four quarters of 2013 and for the first quarter 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
Tertiary oil production					
Gulf Coast region					
Mature properties:					
Brookhaven	2,305	2,339	2,224	2,026	1,877
Eucutta	2,636	2,642	2,504	2,280	2,181
Mallalieu	2,116	2,157	2,042	1,886	1,837
Other mature properties (1)	7,800	7,233	6,761	6,287	6,283
Total mature properties	14,857	14,371	13,531	12,479	12,178
Delhi	5,827	5,479	4,517	4,793	4,708
Hastings	3,956	4,010	3,699	4,270	4,618
Heidelberg	3,943	4,149	4,553	5,206	5,325
Oyster Bayou	2,252	2,518	3,213	3,869	4,055
Tinsley	8,222	8,225	7,951	7,809	8,430
Total Gulf Coast region	39,057	38,752	37,464	38,426	39,314
Rocky Mountain region					
Bell Creek	—	—	49	177	578
Total Rocky Mountain region	—	—	49	177	578
Total tertiary oil production	39,057	38,752	37,513	38,603	39,892
Non-tertiary oil and gas production					
Gulf Coast region					
Mississippi	3,013	2,367	2,692	2,711	2,513
Texas	6,692	6,932	6,548	5,994	6,444
Other	1,153	1,108	1,087	1,041	1,031
Total Gulf Coast region	10,858	10,407	10,327	9,746	9,988
Rocky Mountain region					
Cedar Creek Anticline (2)	8,745	19,935	18,872	18,601	19,007
Other	5,163	4,958	4,819	4,516	4,831
Total Rocky Mountain region	13,908	24,893	23,691	23,117	23,838
Total non-tertiary production	24,766	35,300	34,018	32,863	33,826
Total production	63,823	74,052	71,531	71,466	73,718

(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 the CCA on that date.

Total Production

Total production increased between the first quarters of 2013 and 2014 (9,895 BOE/d or 16%), primarily due to the purchase of additional interests in CCA at the end of the first quarter of 2013. On a sequential-quarter basis, total production increased 2,252 BOE/d (3%) between the fourth quarter of 2013 and the first quarter of 2014 as growth in our new tertiary floods offset declines in our mature tertiary floods, coupled with increased production in our non-tertiary properties. Our production during the three months ended March 31, 2014 was 95% oil, slightly higher than oil production of 93% during the three months ended March 31, 2013.

Tertiary Production

We achieved record quarterly tertiary production during the first quarter of 2014, with average production of 39,892 Bbls/d. First quarter of 2014 tertiary production increased 835 Bbls/d (2%) compared to tertiary production levels in the same period in 2013 and increased 1,289 Bbls/d (3%) when comparing the first quarter of 2014 to the fourth quarter of 2013. 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 year-over-year increase in tertiary production was also impacted by the mid-2013 incident at Delhi Field, which has caused a 1,119 Bbls/d decline in Delhi's production between the first quarters of 2013 and 2014, roughly 3% of the Company's tertiary production in the prior period. 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 received and their application to the calculation of "total net cash flow" which determines the reversionary date, as well as oil prices, production, and production costs. We currently estimate that the reversionary date could occur as late as the fourth quarter of 2014, presuming no insurance proceeds are received before the reversion occurs. Our mature properties are generally on decline with an average annual decline of approximately 12% during 2013. Between the fourth quarter of 2013 and the first quarter of 2014, production from our mature tertiary properties declined just over 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 increased to 33,826 BOE/d during the first quarter of 2014, an increase of 9,060 BOE/d (37%) compared to first quarter 2013 levels, primarily due to production from the purchase of additional interests in the CCA in late March 2013. Sequentially, production from our non-tertiary operations increased 963 BOE/d (3%) compared to fourth quarter 2013 levels, due primarily to increased production at CCA and in Texas at Conroe Field as a result of wells completed late in the fourth quarter of 2013, well upgrades contributing to increased production, as well as downtime in the fourth quarter of 2013 for several workovers. 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 months ended March 31, 2014 increased 9% compared to these revenues for the same period in 2013. The increase was the result of increased production, partially offset by decreases in oil prices. The changes in revenues due to these factors, excluding any impact of our commodity derivative contracts, are reflected in the following table:

In thousands	Three Months Ended March 31, 2014 vs. 2013 Increase (Decrease) in Revenues	Percentage Increase (Decrease) in Revenues
Change in oil and natural gas revenues due to:		
Increase in production	$88,934	16%
Decrease in commodity prices	(38,741)	(7)%
Total increase in oil and natural gas revenues	$50,193	9%

Excluding any impact of our commodity derivative contracts, our net realized commodity prices and NYMEX differentials were as follows during the three months ended March 31, 2014 and 2013:

	Three Months Ended March 31, 2014	2013
Net realized prices:		
Oil price per Bbl	$97.69	$105.59
Natural gas price per Mcf	4.71	3.28
Price per BOE	94.03	99.87
NYMEX differentials:		
Oil per Bbl	$(0.91)	$11.17
Natural gas per Mcf	(0.02)	(0.21)

As reflected in the table above, our average net realized oil price, excluding the impact of commodity derivative contracts, declined 7% from the average price received during the first quarter of 2013. When comparing sequential quarters, the average net realized oil price received during the first quarter of 2014 increased 5% when compared to the $93.00 per Bbl oil price received in the fourth quarter of 2013, due primarily to an improvement in our average realized oil price differential from $4.57 per Bbl below NYMEX in the fourth quarter of 2013 to $0.91 per Bbl below NYMEX in the current quarter. During the first quarter of 2014, we sold approximately 43% of our crude oil at prices based on the 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 53% of our crude oil at prices based on the LLS index price and approximately 26% at prices partially tied to the LLS index price during the first quarter of 2013. The net oil differential we received was primarily impacted by positive differentials in the Gulf Coast region, offset by unfavorable 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 $3.05 per Bbl and $15.31 per Bbl during the three months ended March 31, 2014 and 2013, respectively, and a negative $0.06 per Bbl during the three months ended December 31, 2013. These differentials were impacted significantly by the changes in prices received for our crude oil sold under Light Louisiana Sweet ("LLS") index prices relative to the change in NYMEX prices. This LLS-to-NYMEX differential declined from a positive \$20.15 per Bbl average differential on a trade-month basis in the first quarter of 2013 to a positive \$2.58 per Bbl in the fourth quarter of 2013 and then increased to a positive \$6.06 per Bbl in the first quarter of 2014.

NYMEX oil differentials in the Rocky Mountain region during the first quarter of 2014 were \$9.06 per Bbl below NYMEX, compared to an average differential of \$4.49 per Bbl below NYMEX in the first quarter of 2013 and \$14.00 per Bbl below NYMEX in the fourth quarter of 2013. Differentials in the Rocky Mountain region can move significantly over short periods of time due to refinery and transportation issues. Our Rocky Mountain region differentials were exceptionally strong in the first quarter of 2013 and deteriorated significantly in the fourth quarter of 2013 due to refinery outages. In the first quarter of 2014, we saw improvement in our Rocky Mountain differentials and we consider them to be at a normal level.

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 fourth quarter of 2013, we do not expect the LLS-to-NYMEX differential to return to the more favorable levels seen over the last few years due to the oil transportation capacity 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 table summarizes the impact our oil and natural gas derivative contracts had on our operating results for the three months ended March 31, 2014 and 2013:

In thousands	Three Months Ended March 31, 2014	2013	2014	2013	2014	2013
	Crude Oil Derivative Contracts		Natural Gas Derivative Contracts		Total Commodity Derivative Contracts	
Payment on settlements of commodity derivatives	\$(26,559)	\$—	\$(610)	\$—	\$(27,169)	\$—
Noncash fair value adjustments on commodity derivatives [1]	(48,854)	(11,929)	(646)	—	(49,500)	(11,929)
Total	\$(75,413)	\$(11,929)	\$(1,256)	\$—	\$(76,669)	\$(11,929)

(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 transition 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. Earlier in the first quarter 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 \$26.6 million on our fixed-price swap contracts that settled during the first quarter of 2014, lowering our net realized oil price by $4.23 per Bbl. Based on current futures prices as of May 8, 2014, which average roughly $97.50 per Bbl for the remainder of 2014, and the fixed price swaps that we have in place, which have a weighted average of approximately $93.00 per Bbl for the second through fourth quarters of 2014, we currently expect that we will continue to make payments on the settlements of these contracts. 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.

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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 at March 31, 2014 is included in Note 5, Commodity Derivative Contracts, to the Unaudited Condensed Consolidated Financial Statements.

Production Expenses

Lease Operating Expense

	Three Months Ended March 31,	
In thousands, except per-BOE data	2014	2013
Lease operating expense		
Tertiary	$97,698	$86,808
Non-tertiary	72,681	53,734
Total lease operating expense	$170,379	$140,542
Lease operating expense per BOE		
Tertiary	$27.21	$24.70
Non-tertiary	23.87	24.11
Total lease operating expense per BOE	25.68	24.47

Lease operating expense increased on an absolute-dollar basis during the first quarter of 2014 when compared to the same period in 2013 primarily due to the inclusion in 2014 of a full quarter of lease operating expense from our acquisition of additional interests in CCA, which were acquired in late March of 2013. Also contributing to the higher expense, plus increasing lease operating expense on a per-BOE basis, were increased workover costs; higher power costs; and costs associated with the expansion of our CO_2 floods, including our newest tertiary flood at Bell Creek Field. When comparing the first quarter of 2014 to the fourth quarter of 2013, lease operating expense declined 10% on both an absolute-dollar and per-BOE basis from $188.5 million and $28.67 per BOE in the fourth quarter of 2013, primarily due to the absence in the first quarter of 2014 of Delhi Field remediation costs, as well as lower CO_2 and workover costs in the current quarter. While workover costs were lower in the first quarter of 2014 than the fourth quarter of 2013, they remained high on trend.

Tertiary lease operating expense increased 13% on an absolute-dollar basis and 10% on a per-BOE basis during the first quarter of 2014 compared to the first quarter of 2013, primarily due to the 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 it is in the start-up phase, resulting in high per-BOE operating cost, which is typical when we start up a new tertiary flood. In addition, during the first quarter of 2014 we conducted a higher number of well workovers to repair well failures and incurred higher power costs due to higher rates and usage. When comparing sequential quarters, tertiary lease operating expense decreased $20.3 million (17%) from the fourth quarter of 2013 to the first quarter of 2014, primarily due to $16 million of Delhi remediation costs incurred during the fourth quarter of 2013. Excluding Delhi remediation costs, tertiary lease operating expense decreased $4.3 million (4%) on an absolute-dollar basis and $1.51 (5%) on a per-barrel basis between the fourth quarter of 2013 and the first quarter of 2014, primarily due to lower workover and CO_2 costs during the first quarter 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 first quarter of 2014, approximately 65% 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 first quarter of 2014 was approximately \$0.35 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 first quarter of 2014 was lower than the \$0.39 per Mcf spent during the fourth quarter of 2014 and slightly higher than the \$0.34 per Mcf spent during the first quarter of 2013, both fluctuations of which are primarily due to fluctuations in pricing of our Rocky Mountain region CO_2. 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 \$0.46 per Mcf and \$0.43 per Mcf during the first quarters of 2014 and 2013, respectively.

Non-tertiary lease operating expenses increased 35% on an absolute-dollar basis and decreased 1% on a per-BOE basis between the first quarter of 2013 and the first quarter of 2014, primarily due to our late-March 2013 purchase of additional interests in CCA, which generally have a lower operating cost on a per-BOE basis than our other non-tertiary properties. Non-tertiary lease operating expense was further impacted by increased workover cost during the first quarter of 2014. On a sequential-quarter basis, our non-tertiary lease operating expenses increased \$2.2 million or 3% during the first quarter of 2014 compared to the fourth quarter of 2013 primarily due to higher workover costs, but increased only 2% on a per-BOE basis as higher production partially offset the higher costs.

Taxes Other Than Income

Taxes other than income includes ad valorem, production and franchise taxes. Taxes other than income increased \$7.9 million during the first quarter of 2014 compared to the same period in 2013. The change is generally aligned with fluctuations in oil and natural gas revenues. The increase during the comparative periods 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 March 31,	
In thousands, except per-BOE data and employees	2014	2013
Gross cash compensation and administrative costs	$91,997	$84,006
Gross stock-based compensation	11,226	10,764
Operator labor and overhead recovery charges	(43,140)	(38,394)
Capitalized exploration and development costs	(16,390)	(14,487)
Net G&A expense	$43,693	$41,889
G&A per BOE:		
Net administrative costs	$5.46	$6.05
Net stock-based compensation	1.13	1.24
Net G&A expense	$6.59	$7.29
Employees as of March 31	1,498	1,475

Net G&A expense decreased 10% on a per-BOE basis between the three months ended March 31, 2013 and 2014 due to increased production during the first quarter of 2014. Gross cash compensation and administrative costs increased 10% on an absolute-dollar basis during the three months ended March 31, 2014 compared to the same period in 2013, primarily due to higher compensation-related costs driven by annual merit increases and a 2% increase in the number of employees.

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 12% during the three months ended March 31, 2014 compared to the amounts recovered in the same period in 2013. Capitalized exploration and development costs increased between the periods, primarily due to increased compensation costs subject to capitalization.

Interest and Financing Expenses

	Three Months Ended March 31,	
In thousands, except per-BOE data and interest rates	2014	2013
Cash interest expense	$51,071	$54,002
Noncash interest expense	3,519	3,737
Less: capitalized interest	(5,756)	(21,705)
Interest expense, net	$48,834	$36,034
Interest expense, net per BOE	$7.36	$6.27
Average debt outstanding	$3,521,495	$3,229,289
Average interest rate (1)	5.8%	6.7%

(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 declined between the first quarter of 2013 and 2014 due to our refinancing certain senior subordinated notes which had an interest rate of 9½% and 9¾% in February 2013 with our 4 % Senior Subordinated Notes due 2023. We expect this average interest rate to decline further in future periods as a result of our April 2014 refinancing whereby we issued $1.25 billion in 5½% Notes to replace our $996.3 million in 8¼% Notes and to pay down amounts borrowed on our bank credit facility. 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 borrowings 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 the Company had been previously capitalizing interest, specifically the Riley Ridge gas processing facility, Greencore Pipeline and the tertiary flood at Bell Creek, our capitalized interest decreased significantly, resulting in a 36% increase in net interest expense between the three months ended March 31, 2013 and the three months ended March 31, 2014.

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

	Three Months Ended March 31,	
In thousands, except per-BOE data	2014	2013
Depletion and depreciation of oil and natural gas properties	$108,159	$85,179
Depletion and depreciation of CO_2 properties	7,958	7,337
Asset retirement obligations	2,201	2,104
Depreciation of pipelines, plants and other property and equipment	22,812	18,278
Total DD&A	$141,130	$112,898
DD&A per BOE:		
Oil and natural gas properties	$16.63	$15.20
CO_2, pipelines, plants and other property and equipment	4.64	4.45
Total DD&A cost per BOE	$21.27	$19.65

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 26% on an absolute-dollar basis between the first quarter of 2013 and 2014. The increase on an absolute-dollar basis was due to both higher production volumes and a higher depletion rate per BOE in the first quarter of 2014 compared to the same period in 2013. The DD&A rate per BOE for oil and natural gas properties increased 9% from the first quarter of 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. When comparing the first quarter of 2014 to the fourth quarter of 2013, depletion and depreciation of oil and natural gas properties and asset retirement obligations decreased only slightly, as there were minimal changes to our estimates of proved reserves between the two most recent periods.

Depletion and depreciation of our CO_2 properties, pipelines, plants, and other property and equipment increased 20% on an absolute-dollar and 4% on a per-BOE basis during the three months ended March 31, 2014 compared to the same period 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 increase on a per-BOE basis was lower due to the higher production volumes in the 2014 period.

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 March 31, 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 March 31,	
In thousands, except per-BOE amounts and tax rates	2014	2013
Current income tax expense	$4,618	$10,519

Deferred income tax expense	30,175	43,845
Total income tax expense	$34,793	$54,364
Average income tax expense per BOE	$5.24	$9.46
Effective tax rate	37.4 %	38.3 %

Our income taxes are based on estimated statutory rates of approximately 38% and 38.5% in the first quarters of 2014 and 2013, respectively. Our effective tax rate for the first quarter of 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 first quarter of 2013 was comparable to our estimated statutory rate. The amount recorded as current income tax expense represents our federal taxes reduced by enhanced oil recovery credits, plus our state income taxes, during the three months ended March 31, 2014 and 2013.

As of March 31, 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 March 31,	
Per-BOE data	2014	2013
Oil and natural gas revenues	$94.03	$99.87
Payment on settlements of commodity derivatives	(4.10)	—
Lease operating expenses	(25.68)	(24.47)
Production and ad valorem taxes	(6.39)	(6.17)
Marketing expenses, net of third-party purchases, and plant operating expenses	(1.84)	(1.41)
Production netback	56.02	67.82
CO_2 sales, net of operating and exploration expenses	0.84	0.49
General and administrative expenses	(6.59)	(7.29)
Interest expense, net	(7.36)	(6.27)
Other	0.60	0.22
Changes in assets and liabilities relating to operations	(11.13)	(8.11)
Cash flow from operations	32.38	46.86
DD&A	(21.27)	(19.65)
Deferred income taxes	(4.55)	(7.63)
Loss on early extinguishment of debt	—	(7.70)
Noncash fair value adjustments on commodity derivatives	(7.46)	(2.08)
Other noncash items	9.69	5.45
Net income	$8.79	$15.25

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.

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Management’s Discussion and Analysis of Financial Condition and Results of Operations

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, 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.

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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 April 30, 2014, we had $450.0 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 March 31, 2014:

In thousands	2014	2015	2016	2017	2020	2021	2023	Total
Variable rate debt:								
Bank Credit Facility (weighted average interest rate of 1.9% at March 31, 2014)	$—	$—	$600,000	$—	$—	$—	$—	$600,000
Fixed rate debt:								
8¼% Senior Subordinated Notes due 2020	—	—	—	—	996,273	—	—	996,273
6 % Senior Subordinated Notes due 2021	—	—	—	—	—	400,000	—	400,000
4 % Senior Subordinated Notes due 2023							1,200,000	1,200,000
Other Subordinated Notes	1,072	484	—	2,250	—	—	—	3,806

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 and tender offer to refinance our outstanding 8¼% Senior Subordinated Notes due 2020 at a lower interest rate and for a longer term.

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, 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. 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 that 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 March 31, 2014, our commodity derivative contracts were recorded at their fair value, which was a net liability of approximately $96.8 million, a $49.5 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 March 31, 2014.

Commodity Derivative Sensitivity Analysis

Based on NYMEX and LLS crude oil futures prices and natural gas futures prices as of March 31, 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 March 31, 2014	$(100,536)	$(390)
10% increase in prices	(372,514)	(2,569)
10% decrease in prices	131,010	835

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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 March 31, 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 first 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.

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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 first 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)
January 2014	8,204,548	$16.30	7,905,925	$293.4
February 2014	4,503,552	15.93	4,492,092	221.9
March 2014	73,855	16.40	—	221.9
Total	12,781,955		12,398,017	

(1) Stock repurchases during the first quarter of 2014 other than those under our common stock repurchase program 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, the Company's 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 March 31, 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

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Denbury Resources Inc.

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).
10(a)*	Form of 2014 Performance Cash Award under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.
10(b)*	Form of 2014 TSR Performance Award under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.
10(c)*	Form of 2014 Performance Capital Efficiency Share Award under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.
10(d)*	Form of 2014 Growth and Income Performance Share Award under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.
10(e)*	Form of Restricted Share Award Cliff Vesting Awards under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.
10(f)	Twelfth Amendment to Credit Agreement, dated as of April 15, 2014, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on April 17, 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.

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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.
May 12, 2014	/s/ Mark C. Allen Mark C. Allen Sr. Vice President and Chief Financial Officer
May 12, 2014	/s/ Alan Rhoades Alan Rhoades Vice President and Chief Accounting Officer

INDEX TO EXHIBITS

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101	Interactive Data Files.