DENBURY RESOURCES INC
Form 10-Q
November 06, 2007

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

(Mark One)

þ **Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
*For the quarterly period ended September 30, 2007*

o **Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
**Commission file number 1-12935**

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

| | |
|---|---|
| **Delaware** | **20-0467835** |
| *(State or other jurisdictions of incorporation or organization)* | *(I.R.S. Employer Identification No.)* |
| **5100 Tennyson Parkway**<br>**Suite 1200**<br>**Plano, TX** | **75024** |
| *(Address of principal executive offices)* | *(Zip code)* |

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

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 is a large accelerated filer, an accelerated filer, or a non-accelerated filer. (See definition of accelerated filer and large accelerated filer in Rule 12-b2 of the Exchange Act). (Check one):

Large accelerated filer þ Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Exchange Act Rule 12b-2).
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 October 31, 2007 |
|---|---|
| Common Stock, $.001 par value | 122,134,981 |

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**DENBURY RESOURCES INC.**
**UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS**
(In thousands, except shares)

| | September 30, 2007 | December 31, 2006 |
|---|---|---|
| **Assets** | | |
| **Current assets** | | |
| Cash and cash equivalents | $ 39,414 | $ 53,873 |
| Accrued production receivable | 102,015 | 72,279 |
| Related party receivable Genesis | 777 | 119 |
| Trade and other receivables, net of allowance of $354 and $315 | 47,587 | 24,260 |
| Deferred tax asset | 3,556 | 5,855 |
| Derivative assets | 7,940 | 26,883 |
| Total current assets | 201,289 | 183,269 |
| **Property and equipment** | | |
| Oil and natural gas properties (using full cost accounting) | | |
| Proved | 2,675,463 | 2,226,942 |
| Unevaluated | 358,962 | 293,657 |
| $CO_2$ properties and equipment | 370,102 | 267,483 |
| Other | 47,515 | 43,133 |
| Less accumulated depletion and depreciation | (1,088,782) | (951,447) |
| Net property and equipment | 2,363,260 | 1,879,768 |
| Deposits on property under option or contract | 49,068 | 49,002 |
| Other assets | 60,747 | 27,798 |
| **Total assets** | $ 2,674,364 | $ 2,139,837 |
| **Liabilities and Stockholders Equity** | | |
| **Current liabilities** | | |
| Accounts payable and accrued liabilities | $ 138,500 | $ 139,111 |
| Oil and gas production payable | 65,531 | 52,244 |
| Derivative liabilities | 15,294 | 4,302 |
| Deferred revenue Genesis | 4,070 | 4,070 |
| Short-term capital lease obligations | 719 | 671 |
| Total current liabilities | 224,114 | 200,398 |
| **Long-term liabilities** | | |
| Capital lease obligations | 5,853 | 6,387 |

| | | |
|---|---|---|
| Long-term debt, net of discount or premium | 754,638 | 507,786 |
| Asset retirement obligations | 45,073 | 39,331 |
| Derivative liabilities | 5,198 | 6,834 |
| Deferred revenue Genesis | 25,591 | 28,843 |
| Deferred tax liability | 308,735 | 235,780 |
| Other | 14,682 | 8,419 |
| Total long-term liabilities | 1,159,770 | 833,380 |
| **Stockholders equity** | | |
| Preferred stock, $.001 par value, 25,000,000 shares authorized, none issued and outstanding | | |
| Common stock, $.001 par value, 250,000,000 shares authorized; 122,441,644 and 120,506,815 shares issued at September 30, 2007 and December 31, 2006, respectively | 122 | 121 |
| Paid-in capital in excess of par | 654,488 | 616,046 |
| Retained earnings | 645,203 | 498,032 |
| Accumulated other comprehensive loss | (659) | |
| Treasury stock, at cost, 340,806 and 370,327 shares at September 30, 2007 and December 31, 2006, respectively | (8,674) | (8,140) |
| Total stockholders equity | 1,290,480 | 1,106,059 |
| **Total liabilities and stockholders equity** | $ 2,674,364 | $ 2,139,837 |

(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 September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| **Revenues and other income** | | | | |
| Oil, natural gas and related product sales | | | | |
| Unrelated parties | $ 248,155 | $ 187,786 | $ 634,757 | $ 551,249 |
| Related party Genesis | 58 | 12 | 69 | 1,496 |
| $CO_2$ sales and transportation fees | 3,594 | 2,687 | 10,079 | 7,049 |
| Interest income and other | 1,702 | 1,716 | 5,269 | 5,119 |
| Total revenues | 253,509 | 192,201 | 650,174 | 564,913 |
| **Expenses** | | | | |
| Lease operating expenses | 59,323 | 42,225 | 167,087 | 120,148 |
| Production taxes and marketing expenses | 10,956 | 8,611 | 28,819 | 23,997 |
| Transportation expense Genesis | 1,720 | 1,138 | 4,447 | 3,275 |
| $CO_2$ operating expenses | 1,304 | 842 | 3,211 | 2,272 |
| General and administrative | 11,541 | 10,599 | 34,669 | 35,040 |
| Interest, net of amounts capitalized of $5,431, $3,731, $13,785 and $6,740, respectively | 8,628 | 5,009 | 23,059 | 19,014 |
| Depletion, depreciation and amortization | 52,797 | 41,188 | 140,059 | 110,083 |
| Commodity derivative expense (income) | (3,973) | (12,375) | 7,885 | 10,784 |
| Total expenses | 142,296 | 97,237 | 409,236 | 324,613 |
| Income before income taxes | 111,213 | 94,964 | 240,938 | 240,300 |
| Income tax provision | | | | |
| Current income taxes | 5,197 | 5,419 | 14,158 | 12,856 |
| Deferred income taxes | 38,028 | 30,251 | 79,609 | 80,110 |
| **Net income** | $ 67,988 | $ 59,294 | $ 147,171 | $ 147,334 |
| **Net income per common share basic** | $ 0.56 | $ 0.50 | $ 1.23 | $ 1.27 |
| **Net income per common share diluted** | $ 0.54 | $ 0.48 | $ 1.17 | $ 1.20 |
| **Weighted average common shares outstanding** | | | | |
| Basic | 120,434 | 117,917 | 119,745 | 115,864 |
| Diluted | 125,225 | 123,966 | 125,405 | 123,055 |

(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 September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| **Cash flow from operating activities:** | | | | |
| Net income | $ 67,988 | $ 59,294 | $ 147,171 | $ 147,334 |
| Adjustments needed to reconcile to net cash flow provided by operations: | | | | |
| Depreciation, depletion and amortization | 52,797 | 41,188 | 140,059 | 110,083 |
| Non-cash fair value derivative adjustments | 5,496 | (14,582) | 27,217 | 5,597 |
| Deferred income taxes | 38,028 | 30,251 | 79,609 | 80,110 |
| Deferred revenue Genesis | (1,230) | (1,178) | (3,252) | (3,183) |
| Stock based compensation | 2,820 | 3,440 | 8,270 | 14,697 |
| Amortization of debt issue costs and other | 877 | 570 | 2,422 | 987 |
| Changes in assets and liabilities related to operations: | | | | |
| Accrued production receivables | (8,325) | 3,697 | (30,395) | (463) |
| Trade and other receivables | (11,351) | (6,805) | (23,136) | (12,745) |
| Other assets | (259) | 1,400 | (405) | (1,232) |
| Accounts payable and accrued liabilities | 16,864 | 17,280 | 1,363 | (6,488) |
| Oil and gas production payable | 4,077 | 1,003 | 13,288 | 9,309 |
| Other liabilities | 1,432 | (193) | 2,600 | 288 |
| **Net cash provided by operating activities** | 169,214 | 135,365 | 364,811 | 344,294 |
| **Cash flow used for investing activities:** | | | | |
| Oil and natural gas expenditures | (170,812) | (126,887) | (470,121) | (376,988) |
| Acquisitions of oil and gas properties | 1,959 | (1,315) | (44,701) | (315,650) |
| Change in accrual for capital expenditures | 4,908 | (1,617) | (3,861) | 12,995 |
| Acquisitions of $CO_2$ assets and $CO_2$ capital expenditures | (33,981) | (14,450) | (102,408) | (42,617) |
| Investment in Genesis | (28,563) | | (28,563) | |
| Purchases of other assets | (3,853) | (4,230) | (8,276) | (7,912) |
| Dispositions of other assets | 57 | | 1,746 | 222 |
| Proceeds from sales of oil and gas property and equipment | 127 | 5,893 | 5,967 | 7,931 |
| Deposits on properties under option or contract | (12) | 126 | (66) | 26,425 |
| Increase in restricted cash | (875) | (869) | (1,781) | (934) |
| **Net cash used for investing activities** | (231,045) | (143,349) | (652,064) | (696,528) |

| | | | | |
|---|---|---|---|---|
| **Cash flow from financing activities:** | | | | |
| Bank repayments | | (10,000) | (140,000) | (140,000) |
| Bank borrowings | 60,000 | 10,000 | 236,000 | 210,000 |
| Payments on capital lease obligations | (170) | (145) | (497) | (425) |
| Issuance of subordinated debt | | | 150,750 | |
| Issuance of common stock | 4,371 | 4,952 | 15,058 | 137,263 |
| Income tax benefit from equity awards | 7,504 | 5,041 | 16,344 | 15,193 |
| Purchase of treasury stock | (2,853) | (3,423) | (2,872) | (5,545) |
| Costs of debt financing | (184) | (329) | (1,989) | (417) |
| **Net cash provided by financing activities** | 68,668 | 6,096 | 272,794 | 216,069 |
| **Net increase (decrease) in cash and cash equivalents** | 6,837 | (1,888) | (14,459) | (136,165) |
| Cash and cash equivalents at beginning of period | 32,577 | 30,812 | 53,873 | 165,089 |
| **Cash and cash equivalents at end of period** | $ 39,414 | $ 28,924 | $ 39,414 | $ 28,924 |
| **Supplemental disclosure of cash flow information:** | | | | |
| Cash paid during the period for interest | $ 2,980 | $ 1,519 | $ 24,329 | $ 17,416 |
| Cash paid during the period for income taxes | 1,431 | 4 | 8,801 | 4,210 |
| Interest capitalized | 5,431 | 3,731 | 13,785 | 6,740 |

(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 September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |

(See accompanying Notes to Unaudited Condensed Consolidated Financial Statements)

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**DENBURY RESOURCES INC.**

***Notes to Unaudited Condensed Consolidated Financial Statements***

## Note 1. Basis of Presentation

*Interim Financial Statements*

The accompanying unaudited condensed consolidated financial statements of Denbury Resources Inc. and its subsidiaries have been prepared in accordance with the instructions to Form 10-Q and do not include all of the information and footnotes required by accounting principles generally accepted in the United States for complete financial statements. Unless indicated otherwise or the context requires, the terms we, our, us, Denbury or Compa refer to Denbury Resources Inc. and its subsidiaries. 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, 2006. Any capitalized terms used but not defined in these Notes to Unaudited Condensed Consolidated Financial Statements have the same meaning given to them in the Form 10-K.

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 fiscal year. In management s opinion, the accompanying unaudited condensed consolidated financial statements include all adjustments (of a normal recurring nature) necessary to present fairly the consolidated financial position of Denbury as of September 30, 2007 and the consolidated results of its operations and cash flows for the three and nine month periods ended September 30, 2007 and 2006. Certain prior period items have been reclassified to make the classification consistent with the classification in the most recent quarter.

*Net Income Per Common Share*

Basic net income per common share is computed by dividing net income 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 also considers the impact on net income and common shares for the potential dilution from stock options, stock appreciation rights ( SARs ), non-vested restricted stock and any other convertible securities outstanding. For the three and nine month periods ended September 30, 2007 and 2006, there were no adjustments to net income for purposes of calculating diluted net income per common share. In April 2006, we issued 3,492,595 shares of common stock in a public offering. The following is a reconciliation of the weighted average common shares used in the basic and diluted net income per common share calculations for the three and nine month periods ended September 30, 2007 and 2006.

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| *Share amounts in thousands* | 2007 | 2006 | 2007 | 2006 |
| Weighted average common shares basic | 120,434 | 117,917 | 119,745 | 115,864 |
| Potentially dilutive securities: | | | | |
| Stock options and SARs | 4,010 | 5,183 | 4,939 | 6,172 |
| Restricted stock | 781 | 866 | 721 | 1,019 |
| Weighted average common shares diluted | 125,225 | 123,966 | 125,405 | 123,055 |

The weighted average common shares basic amount excludes 1,351,370 shares at September 30, 2007 and 1,422,229 shares at September 30, 2006, of non-vested restricted stock that is subject to future vesting over time. 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 weighted average common shares diluted, the non-vested restricted stock is included in the computation using the treasury stock method, with the proceeds equal to the average unrecognized compensation during the period, adjusted for any estimated future tax consequences recognized directly in equity. The dilution impact of these shares on our earnings per share calculation may increase in future periods, depending on the market price of our common stock during those periods.

**DENBURY RESOURCES INC.**

***Notes to Unaudited Condensed Consolidated Financial Statements***

For the three months ended September 30, 2007 and 2006, stock options and SARs to purchase approximately 8,000 and 111,000 shares of common stock, and for the nine months ended September 30, 2007 and 2006, stock options and SARs to purchase approximately 87,000 and 117,000 shares of common stock, respectively, were outstanding but excluded from the diluted net income per common share calculations, as the exercise prices of the options exceeded the average market price of the Company s common stock during these periods and would be anti-dilutive to the calculations.

**Recently Adopted Accounting Pronouncement**

*Uncertain Tax Positions*

In June 2006, the Financial Accounting Standards Board ( FASB ) issued Interpretation 48 ( FIN 48 ), *Accounting for Uncertainties in Income Taxes* an interpretation of FASB Statement No. 109, *Accounting for Income Taxes*. This interpretation addresses how tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under FIN 48, the Company may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties on income taxes, accounting in interim periods and required increased disclosures.

We adopted the provisions of FIN 48 as of January 1, 2007. As a result of the implementation, we determined that approximately $4.0 million of tax benefits previously recognized were considered uncertain tax positions, as the timing of these deductions may not be sustained upon examination by taxing authorities. As such, upon adoption of FIN 48, we recorded income taxes payable of $4.3 million (including $0.3 million in estimated interest) which was offset by a corresponding reduction of the deferred tax liability of $4.1 million for the tax position that we believe will ultimately be sustained. At January 1, 2007, the total amount of unrecognized tax benefits was $4.5 million, exclusive of interest.

There was no cumulative adjustment made to the opening balance of retained earnings at January 1, 2007. Our uncertain tax positions relate primarily to timing differences and we do not believe any of such uncertain tax positions will materially impact our effective tax rate in future periods. The amount of unrecognized tax benefits are expected to change over the next 12 months; however, such change is not expected to have a significant impact on our results of operations or financial position.

We file consolidated and separate income tax returns in the U.S. federal jurisdiction and in many state jurisdictions. We are currently under examination by the Internal Revenue Service and different state authorities. The Internal Revenue Service concluded its examination of our 2004 tax year during the third quarter of 2007 and is expected to begin an examination of our 2005 tax year during the fourth quarter of 2007. The state of Mississippi concluded its audit of tax years 1998 through 2000 during the third quarter of 2007 and is currently examining years 2001 through 2004. Neither of the concluded examinations by the Internal Revenue Service and the state of Mississippi resulted in any material assessments. As a result of the examinations concluded during the third quarter, we decreased our total amount of unrecognized tax benefits from $4.5 million to $3.5 million. These adjustments all related to temporary timing differences and did not have any impact on our effective tax rate. We are also under examination by the state of Louisiana for years 2002 through 2004.

We have not paid any significant interest or penalties associated with our income taxes, but classify both interest expense and penalties as part of our income tax expense.

**Recently Issued Accounting Pronouncement**

*Fair Value Option for Financial Assets and Liabilities*

In February 2007, the FASB issued FASB Statement No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities ( FAS 159 ).* FAS 159 permits entities to choose to measure many financial

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***Notes to Unaudited Condensed Consolidated Financial Statements***

instruments and certain other items at fair value, with the objective of improving financial reporting by giving entities the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. The provisions of FAS 159 are effective for us beginning January 1, 2008. We have not yet determined what impact, if any, this pronouncement will have on our financial position or results of operations.

**Note 2. Acquisitions**

*2007 Acquisition*

On March 30, 2007, Denbury completed the acquisition of the Seabreeze Complex, which is composed of two significant fields and four smaller fields, in the general area of Houston, Texas. At the time of acquisition these fields were producing approximately 400 BOE/d and had estimated current conventional proved reserves of approximately 525 MBOE. Two of these fields are future potential $CO_2$ tertiary flood candidates. Tertiary flooding at these fields is not expected to begin until 2010 or 2011, following completion of the proposed $CO_2$ pipeline from Louisiana to Hastings Field, near Houston, Texas.

The adjusted purchase price is approximately $39.4 million, after adjusting for interim net cash flow between the effective date and closing date of the acquisition, and minor purchase price adjustments. The purchase price was allocated between proved and unevaluated oil and natural gas properties based on a risk adjusted analysis of the total estimated value of the proved and probable reserves acquired. Based on this analysis, $5.5 million was assigned to proved properties and $33.9 million was assigned to unevaluated properties. The unevaluated costs are currently excluded from the amortization base and will be transferred to the amortization base as we develop and test the tertiary recovery projects planned in these fields.

*2006 Acquisitions*

On January 31, 2006, we completed an acquisition of three producing oil properties that are future potential $CO_2$ tertiary oil flood candidates: Tinsley Field approximately 40 miles northwest of Jackson, Mississippi; Citronelle Field in Southwest Alabama, and the smaller South Cypress Creek Field near the Company s Eucutta Field in Eastern Mississippi. The adjusted purchase price was approximately $250 million (including the $25 million deposited as earnest money as of December 31, 2005), of which $124 million was assigned to unevaluated properties.

During May 2006, we purchased the Delhi Holt-Bryant Unit ( Delhi ) in northern Louisiana for $50 million, plus a 25% reversionary interest to the seller after we have achieved $200 million in net operating revenue, as defined. Delhi is also a future potential $CO_2$ tertiary oil flood candidate. Approximately $49 million of the purchase price was assigned to unevaluated properties.

We have not presented any pro forma information for the acquired properties as the pro forma effect was not material to our results of operations for the nine month periods ended September 30, 2007 or 2006.

**Note 3. Asset Retirement Obligations**

In general, our future asset retirement obligations relate to future costs associated with plugging and abandonment of our oil, natural gas and $CO_2$ wells, removal of equipment and facilities from leased acreage and land restoration. The fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred, discounted to its present value using our credit adjusted risk-free interest rate, and a corresponding amount capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted each period, and the capitalized cost is depreciated over the useful life of the related asset.

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***Notes to Unaudited Condensed Consolidated Financial Statements***

The following table summarizes the changes in our asset retirement obligations for the nine months ended September 30, 2007.

| *Amounts in thousands* | | Nine Months Ended September 30, 2007 |
|---|---|---|
| Balance, beginning of period | $ | 41,107 |
| Liabilities incurred and assumed during period | | 3,540 |
| Revisions in estimated retirement obligations | | 798 |
| Liabilities settled during period | | (964) |
| Accretion expense | | 2,232 |
| Balance, end of period | $ | 46,713 |

At September 30, 2007, $1.6 million of our asset retirement obligation was classified in Accounts payable and accrued liabilities under current liabilities in our Condensed Consolidated Balance Sheets. Liabilities incurred and assumed during the period are primarily for properties acquired during 2007. We hold cash and liquid investments in escrow accounts that are legally restricted for certain of our asset retirement obligations. The balance of these escrow accounts was $9.4 million at September 30, 2007 and $7.6 million at December 31, 2006 and is included in Other assets in our Condensed Consolidated Balance Sheets.

**Note 4. Notes Payable and Long-Term Indebtedness**

| *Amounts in thousands* | | September 30, 2007 | | December 31, 2006 |
|---|---|---|---|---|
| 7.5% Senior Subordinated Notes due 2015 | $ | 300,000 | $ | 150,000 |
| Premium on Senior Subordinated Notes due 2015 | | 707 | | |
| 7.5% Senior Subordinated Notes due 2013 | | 225,000 | | 225,000 |
| Discount on Senior Subordinated Notes due 2013 | | (1,069) | | (1,214) |
| Senior bank loan | | 230,000 | | 134,000 |
| Capital lease obligations Genesis | | 5,402 | | 5,869 |
| Capital lease obligations | | 1,170 | | 1,189 |
| Total | | 761,210 | | 514,844 |
| Less current obligations | | 719 | | 671 |
| Long-term debt and capital lease obligations | $ | 760,491 | $ | 514,173 |

On March 31, 2007, we amended our Sixth Amended and Restated Credit Agreement, the instrument governing our senior bank loan. The amendment (i) increased the commitment amount that the banks are committed to fund from $250 million to $350 million, (ii) reconfirmed the borrowing base of $500 million, (iii) authorized the $150 million subordinated debt offering , and (iv) authorized us to enter into a sale-leaseback type transaction for our $CO_2$ pipelines, not to exceed $300 million, with Genesis Energy, L.P.

On April 3, 2007, we issued $150 million of Senior Subordinated Notes due 2015 as an additional issuance under our existing indenture governing our December 2005 sale of $150 million of 7.5% Senior Subordinated Notes due 2015. The notes, which carry a coupon rate of 7.5%, were sold at 100.5% of par, which equates to an effective yield to maturity of approximately 7.4%. Net proceeds from the sale were approximately $149.2 million. The net proceeds were used to repay a portion of the outstanding borrowings under our bank credit facility.

**DENBURY RESOURCES INC.**

***Notes to Unaudited Condensed Consolidated Financial Statements***

**5. Related Party Transactions Genesis Energy**

*Interest in and Transactions with Genesis*

Denbury is the general partner and owns an aggregate 9.25% interest in Genesis Energy, L.P. ( Genesis ), a publicly traded master limited partnership. We account for our 9.25% ownership in Genesis under the equity method of accounting as we have significant influence over the limited partnership; however, our control is limited under the limited partnership agreement and therefore we do not consolidate Genesis. Denbury received pro-rata distributions from Genesis of $0.9 million and $0.7 million for the nine months ended September 30, 2007 and 2006, respectively. We also received $0.1 million in each of these periods in directors fees for certain officers of Denbury that are board members of Genesis. There are no guarantees by Denbury or any of its other subsidiaries of the debt of Genesis or of Genesis Energy, Inc.

On July 25, 2007, Genesis closed on a previously announced acquisition wherein they acquired several energy related businesses from the Davison family of Ruston, Louisiana for total consideration of approximately $623 million (net of cash acquired at closing and subject to final purchase price adjustments). The acquisition agreement with the Davison s provided that Genesis deliver to them $560 million of consideration, half in common units at an agreed value of $20.8036 per unit (as compared to a value of $24.52 per unit for accounting purposes) and half in cash, subject to specified purchase price adjustments. These businesses include a trucking operation for petroleum products and other bulk commodities, terminal storage of refined petroleum products, a refinery service operation which processes sour gas streams at several refining operations, and a wholesale petroleum products marketing business. Approximately one-half of the acquisition was funded by debt from Genesis bank credit facility and approximately one-half through the issuance of Genesis common units to the seller. In conjunction with that acquisition, we exercised our right to maintain our pro rata (7.4%) ownership of common units, acquiring 1,074,882 additional common units for approximately $22.4 million, in addition to our capital contribution of an additional $6.2 million as general partner to maintain our 2% general partner s capital interest.

*Oil Sales and Transportation Services*

We utilize Genesis trucking services and common carrier pipeline in Mississippi to transport certain of our crude oil production to sales points where it is sold to third party purchasers. In the first nine months of 2007 and 2006, we expensed $4.4 million and $3.3 million, respectively, for these transportation services.

*Transportation Leases*

In late 2004 and early 2005, we entered into pipeline transportation agreements with Genesis to transport our crude oil from certain of our fields in Southwest Mississippi and to transport $CO_2$ from our main $CO_2$ pipeline to Brookhaven Field for our tertiary operations. We have accounted for these agreements as capital leases. The pipelines held under these capital leases are classified as property and equipment and are amortized using the straight-line method over the lease terms. Lease amortization is included in depreciation expense. The related obligations are recorded as debt. At September 30, 2007, we had $5.4 million of capital lease obligations with Genesis recorded as liabilities in our Condensed Consolidated Balance Sheet, of which $0.7 million was current. At December 31, 2006, we had $5.9 million of capital lease obligations with Genesis recorded as liabilities in our Condensed Consolidated Balance Sheet, of which $0.6 million was current.

*$CO_2$ Volumetric Production Payments*

During 2003 through 2005, we sold 280.5 Bcf of $CO_2$ to Genesis under three separate volumetric production payment agreements. We have recorded the net proceeds of these volumetric production payment sales as deferred revenue and recognize such revenue as $CO_2$ is delivered under the volumetric production payments. At September 30, 2007 and December 31, 2006, $29.7 million and $32.9 million, respectively, were recorded as deferred revenue of which $4.1 million was included in current liabilities at September 30, 2007 and December 31, 2006. We recognized deferred revenue for deliveries under these volumetric production payments of $1.2 million during each of the three month periods ended September 30, 2007 and 2006 and $3.3 million and $3.2 million for the nine month

**DENBURY RESOURCES INC.**

***Notes to Unaudited Condensed Consolidated Financial Statements***

periods ended September 30, 2007 and 2006, respectively. We provide Genesis with certain processing and transportation services in connection with these agreements for a fee of approximately $0.17 per Mcf of $CO_2$. For these services, we recognized revenues of $1.5 million and $1.3 million for the three month periods ended September 30, 2007 and 2006, respectively, and $3.8 million and $3.5 million for the nine months ended September 30, 2007 and 2006, respectively.

We had a net receivable from Genesis of $0.8 million at September 30, 2007 and $0.1 million at December 31, 2006 in current assets and a long-term payable to Genesis of $0.5 million at September 30, 2007.

**Note 6. Derivative Instruments and Hedging Activities**

*Oil and Gas Derivative Contracts*

We do not apply hedge accounting treatment to our oil and gas derivative contracts and 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 derivative income and expense in our Condensed Consolidated Statements of Operations.

The following is a summary of commodity derivative income and expense included in our Condensed Consolidated Statements of Operations:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| *Amounts in thousands* | 2007 | 2006 | 2007 | 2006 |
| Receipt (payment) on settlements of derivative contracts Oil | $ (3,018) | $ (2,207) | $ (3,999) | $ (5,187) |
| Receipt (payment) of settlements of derivative contracts Gas | 12,432 | | 23,383 | |
| Fair value adjustments to derivative contracts income (expense) | (5,441) | 14,582 | (27,269) | (5,597) |
| Commodity derivative income (expense) | $ 3,973 | $ 12,375 | $ (7,885) | $ (10,784) |

*Oil and Natural Gas Commodity Derivative Contracts at September 30, 2007:*

*Crude Oil Contracts at September 30, 2007:*

| | NYMEX Contract Prices Per Bbl | | Estimated fair value asset (liability) at September 30, 2007 |
|---|---|---|---|
| Type of Contract and Period | Bbls/d | Swap Price | (in thousands) |
| Swap Contracts | | | |
| Oct. 2007 Dec. 2007 | 2,000 | $ 58.93 | $ (3,883) |
| Jan. 2008 Dec. 2008 | 2,000 | 57.34 | (13,442) |

*Natural Gas Contracts at September 30, 2007:*

Estimated
fair value

| Type of Contract and Period | NYMEX Contract Prices Per MMBtu | | asset (liability) at September 30, 2007 (in thousands) |
|---|---|---|---|
| | MMBtu/d | Swap Price | |
| Swap Contracts | | | |
| Oct. 2007 Dec. 2007 | 20,000 | $ 7.99 | $ 1,815 |
| Oct. 2007 Dec. 2007 | 40,000 | 7.96 | 3,521 |
| Oct. 2007 Dec. 2007 | 15,000 | 7.95 | 1,306 |
| Jan. 2008 Dec. 2008 | 20,000 | 7.89 | (445) |
| Jan. 2008 Dec. 2008 | 20,000 | 7.91 | (304) |
| Jan. 2008 Dec. 2008 | 20,000 | 7.94 | (91) |

**DENBURY RESOURCES INC.**

***Notes to Unaudited Condensed Consolidated Financial Statements***

At September 30, 2007, our oil and natural gas derivative contracts were recorded at their fair value, which was a net liability of $11.5 million.

*Interest Rate Lock Derivative Contracts*

In January 2007, we entered into interest rate lock contracts to remove our exposure to possible interest rate fluctuations related to our commitment to the sale-leaseback financing of certain equipment for $CO_2$ recycling facilities at our tertiary oil fields. The interest rate lock contracts cover two groups of equipment currently being constructed that we have committed to finance with Bank of America Leasing & Capital LLC. This equipment has estimated completion dates during the fourth quarter of 2007 and in mid-year 2008, with total estimated costs of approximately $15 million and $24 million, respectively. We are applying hedge accounting to these contracts as provided under SFAS No. 133. For these instruments designated as interest rate hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income (loss) until the hedged item is recognized in earnings. Amounts representing hedge ineffectiveness are recorded in earnings. Hedge effectiveness is assessed quarterly based on the total change in the contract s fair value.

At September 30, 2007, the interest rate lock contracts had a fair value liability of approximately $1.0 million that was recorded in our September 30, 2007 Condensed Consolidating Balance Sheet. We recorded $0.7 million (net of taxes of $0.4 million) in accumulated other comprehensive income in our September 30, 2007 Condensed Consolidating Balance Sheet and the ineffectiveness totaling $0.1 million was recognized as income in our Condensed Consolidating Statement of Operations for the nine months ended September 30, 2007.

**Note 7. Condensed Consolidating Financial Information**

Our subordinated debt is fully and unconditionally guaranteed jointly and severally by all of Denbury Resources Inc. s subsidiaries other than minor subsidiaries, except that with respect to our $225 million of 7.5% Senior Subordinated Notes due 2013, Denbury Resources Inc. and Denbury Onshore, LLC are co-obligors. Except as noted in the foregoing sentence, Denbury Resources Inc. is the sole issuer and Denbury Onshore, LLC is a subsidiary guarantor. The results of our equity interest in Genesis are reflected through the equity method by one of our subsidiaries, Denbury Gathering & Marketing. Each subsidiary guarantor and the subsidiary co-obligor are 100% owned, directly or indirectly, by Denbury Resources Inc. The following is condensed consolidating financial information for Denbury Resources Inc., Denbury Onshore, LLC, and subsidiary guarantors:

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**DENBURY RESOURCES INC.**

***Notes to Unaudited Condensed Consolidated Financial Statements***

*Condensed Consolidating Balance Sheets*

| | September 30, 2007 | | | | |
|---|---|---|---|---|---|
| *Amounts in thousands* | Denbury Resources Inc. | Denbury Onshore, LLC | Other Guarantor Subsidiaries | Eliminations | Denbury Resources Inc. Consolidated |
| Assets | | | | | |
| Current assets | $ 422,178 | $ 197,032 | $ 8,012 | $ (425,933) | $ 201,289 |
| Property and equipment | | 2,363,247 | 13 | | 2,363,260 |
| Investment in subsidiaries (equity method) | 856,836 | | 818,723 | (1,675,559) | |
| Other assets | 312,173 | 67,963 | 38,699 | (309,020) | 109,815 |
| Total assets | $ 1,591,187 | $ 2,628,242 | $ 865,447 | $ (2,410,512) | $ 2,674,364 |
| Liabilities and Stockholders Equity | | | | | |
| Current liabilities | $ | $ 641,727 | $ 8,320 | $ (425,933) | $ 224,114 |
| Long-term liabilities | 300,707 | 1,167,792 | 291 | (309,020) | 1,159,770 |
| Stockholders equity | 1,290,480 | 818,723 | 856,836 | (1,675,559) | 1,290,480 |
| Total liabilities and stockholders equity | $ 1,591,187 | $ 2,628,242 | $ 865,447 | $ (2,410,512) | $ 2,674,364 |

| | December 31, 2006 | | | | |
|---|---|---|---|---|---|
| *Amounts in thousands* | Denbury Resources Inc. | Denbury Onshore, LLC | Other Guarantor Subsidiaries | Eliminations | Denbury Resources Inc. Consolidated |
| Assets | | | | | |
| Current assets | $ 392,372 | $ 180,476 | $ 3,662 | $ (393,241) | $ 183,269 |
| Property and equipment | | 1,879,742 | 26 | | 1,879,768 |
| Investment in subsidiaries (equity method) | 709,611 | | 698,380 | (1,407,991) | |
| Other assets | 154,076 | 64,391 | 10,794 | (152,461) | 76,800 |
| Total assets | $ 1,256,059 | $ 2,124,609 | $ 712,862 | $ (1,953,693) | $ 2,139,837 |

| | | | | | |
|---|---|---|---|---|---|
| Liabilities and Stockholders Equity | | | | | |
| Current liabilities | $ | $ 590,602 | $ 3,037 | $ (393,241) | $ 200,398 |
| Long-term liabilities | 150,000 | 835,627 | 214 | (152,461) | 833,380 |
| Stockholders equity | 1,106,059 | 698,380 | 709,611 | (1,407,991) | 1,106,059 |
| Total liabilities and stockholders equity | $ 1,256,059 | $ 2,124,609 | $ 712,862 | $ (1,953,693) | $ 2,139,837 |

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**DENBURY RESOURCES INC.**

***Notes to Unaudited Condensed Consolidated Financial Statements***

*Condensed Consolidating Statements of Operations*

| | Three Months Ended September 30, 2007 | | | | |
|---|---|---|---|---|---|
| *Amounts in thousands* | Denbury Resources Inc. | Denbury Onshore, LLC | Other Guarantor Subsidiaries | Eliminations | Denbury Resources Inc. Consolidated |
| Revenues | $ 5,625 | $ 253,316 | $ 193 | $ (5,625) | $ 253,509 |
| Expenses | 5,750 | 141,539 | 632 | (5,625) | 142,296 |
| Income (loss) before the following: | (125) | 111,777 | (439) | | 111,213 |
| Equity in net earnings of subsidiaries | 68,505 | | 68,996 | (137,501) | |
| Income before income taxes | 68,380 | 111,777 | 68,557 | (137,501) | 111,213 |
| Income tax provision | 392 | 42,781 | 52 | | 43,225 |
| Net income | $ 67,988 | $ 68,996 | $ 68,505 | $ (137,501) | $ 67,988 |

| | Three Months Ended September 30, 2006 | | | | |
|---|---|---|---|---|---|
| *Amounts in thousands* | Denbury Resources Inc. | Denbury Onshore, LLC | Other Guarantor Subsidiaries | Eliminations | Denbury Resources Inc. Consolidated |
| Revenues | $ 2,812 | $ 189,226 | $ 163 | $ | $ 192,201 |
| Expenses | 2,917 | 93,751 | 569 | | 97,237 |
| Income (loss) before the following: | (105) | 95,475 | (406) | | 94,964 |
| Equity in net earnings of subsidiaries | 59,393 | | 59,847 | (119,240) | |
| Income before income taxes | 59,288 | 95,475 | 59,441 | (119,240) | 94,964 |
| Income tax provision (benefit) | (6) | 35,628 | 48 | | 35,670 |
| Net income | $ 59,294 | $ 59,847 | $ 59,393 | $ (119,240) | $ 59,294 |

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**DENBURY RESOURCES INC.**

***Notes to Unaudited Condensed Consolidated Financial Statements***

*Condensed Consolidating Statements of Operations (continued)*

| | Nine Months Ended September 30, 2007 | | | | |
|---|---|---|---|---|---|
| | Denbury Resources Inc. | Denbury Onshore, LLC | Other Guarantor Subsidiaries | Eliminations | Denbury Resources Inc. Consolidated |
| *Amounts in thousands* | | | | | |
| Revenues | $ 13,969 | $ 649,927 | $ 247 | $ (13,969) | $ 650,174 |
| Expenses | 14,300 | 406,985 | 1,920 | (13,969) | 409,236 |
| Income (loss) before the following: | (331) | 242,942 | (1,673) | | 240,938 |
| Equity in net earnings of subsidiaries | 147,884 | | 149,566 | (297,450) | |
| Income before income taxes | 147,553 | 242,942 | 147,893 | (297,450) | 240,938 |
| Income tax provision | 382 | 93,376 | 9 | | 93,767 |
| Net income | $ 147,171 | $ 149,566 | $ 147,884 | $ (297,450) | $ 147,171 |

| | Nine Months Ended September 30, 2006 | | | | |
|---|---|---|---|---|---|
| | Denbury Resources Inc. | Denbury Onshore, LLC | Other Guarantor Subsidiaries | Eliminations | Denbury Resources Inc. Consolidated |
| *Amounts in thousands* | | | | | |
| Revenues | $ 8,406 | $ 555,785 | $ 722 | $ | $ 564,913 |
| Expenses | 8,678 | 314,606 | 1,329 | | 324,613 |
| Income (loss) before the following: | (272) | 241,179 | (607) | | 240,300 |
| Equity in net earnings of subsidiaries | 147,594 | | 148,440 | (296,034) | |
| Income before income taxes | 147,322 | 241,179 | 147,833 | (296,034) | 240,300 |
| Income tax provision (benefit) | (12) | 92,739 | 239 | | 92,966 |
| Net income | $ 147,334 | $ 148,440 | $ 147,594 | $ (296,034) | $ 147,334 |

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**DENBURY RESOURCES INC.**

***Notes to Unaudited Condensed Consolidated Financial Statements***

*Condensed Consolidating Statements of Cash Flows*

| | Nine Months Ended September 30, 2007 | | | | |
|---|---|---|---|---|---|
| *Amounts in thousands* | Denbury Resources Inc. | Denbury Onshore, LLC | Other Guarantor Subsidiaries | Eliminations | Denbury Resources Inc. Consolidated |
| Cash flow from operations | $ 33 | $ 364,108 | $ 670 | $ | $ 364,811 |
| Cash flow from investing activities | (177,291) | (652,064) | | 177,291 | (652,064) |
| Cash flow from financing activities | 177,291 | 272,794 | | (177,291) | 272,794 |
| Net increase (decrease) in cash | 33 | (15,162) | 670 | | (14,459) |
| Cash, beginning of period | 1 | 52,225 | 1,647 | | 53,873 |
| Cash, end of period | $ 34 | $ 37,063 | $ 2,317 | $ | $ 39,414 |

| | Nine Months Ended September 30, 2006 | | | | |
|---|---|---|---|---|---|
| *Amounts in thousands* | Denbury Resources Inc. | Denbury Onshore, LLC | Other Guarantor Subsidiaries | Eliminations | Denbury Resources Inc. Consolidated |
| Cash flow from operations | $ | $ 343,593 | $ 701 | $ | $ 344,294 |
| Cash flow from investing activities | (146,911) | (696,528) | | 146,911 | (696,528) |
| Cash flow from financing activities | 146,911 | 216,069 | | (146,911) | 216,069 |
| Net increase (decrease) in cash | | (136,866) | 701 | | (136,165) |
| Cash, beginning of period | 1 | 164,408 | 680 | | 165,089 |
| Cash, end of period | $ 1 | $ 27,542 | $ 1,381 | $ | $ 28,924 |

**Note 8. Subsequent Events**

In October 2007, we announced that we had entered into an agreement with a privately held company to sell our Louisiana natural gas assets for approximately $180 million plus any amounts received from a net profits interest (before closing adjustments). The sale is expected to close in early December 2007 and is subject to satisfactory completion of customary due diligence and closing conditions. The agreement contemplates an effective date of August 1, 2007, and consequently operating net revenue after August 1, net of capital expenditures, along with any other purchase price adjustments, will be accounted for as an adjustment to the ultimate sales price. The potential net profits interest relates to a sharing of production from a well in South Chauvin field if operating income from that well exceeds certain levels, which we believe could potentially increase the ultimate sales price by up to 10%. We do not expect to record any gain or loss on the sale in accordance with the full cost method of accounting.

Our Board of Directors have unanimously approved , subject to shareholder approval, an amendment to our Restated Certificate of Incorporation to increase the number of shares of common stock we are authorized to issue from 250,000,000 shares to 600,000,000 shares and to effect a 2-for-1 stock split of Denbury s common stock to holders of record on December 5, 2007. Stockholders of record, as of October 8, 2007, are scheduled to vote at a special meeting of stockholders on November 19, 2007 to approve the increase in authorized shares and the 2-for-1 stock split.

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**DENBURY RESOURCES INC.**

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

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

You should read the following in conjunction with our financial statements contained herein and our Form 10-K for the year ended December 31, 2006, along with Management s Discussion and Analysis of Financial Condition and Results of Operations contained in such Form 10-K. Any terms used but not defined in the following discussion have the same meaning given to them in the Form 10-K.

We are a growing independent oil and gas company engaged in acquisition, development and exploration activities in the U.S. Gulf Coast region. We are the largest oil and natural gas producer in Mississippi; own the largest carbon dioxide ( $CO_2$ ) reserves east of the Mississippi River used for tertiary oil recovery, and hold significant operating acreage in the Barnett Shale play near Fort Worth, Texas, onshore Louisiana and Alabama, and properties in Southeast Texas. Our goal is to increase the value of acquired properties through a combination of exploitation, drilling, and proven engineering extraction processes, including secondary and tertiary recovery operations. Our corporate headquarters are in Plano, Texas (a suburb of Dallas), and we have five primary field offices located in Laurel, Mississippi; McComb, Mississippi; Brandon, Mississippi; Cleburne, Texas; and Houma, Louisiana.

### Overview

**Operating results.** In the third quarter of 2007, we set a corporate record for quarterly cash flow from operations, recognizing $169.2 million, a 25% increase over the $135.4 million cash flow from operations during the third quarter of 2006. Our third quarter 2007 net income of $68.0 million was 15% higher than our $59.3 million of net income during third quarter of 2006, less of a percentage increase than the increase in cash flow from operations primarily due to a $20.0 million decrease in pre-tax income between the respective periods from non-cash fair value adjustments associated with our commodity derivative contracts. Record high production levels, higher oil prices, and $11.6 million of incremental net cash receipts on our derivative contracts contributed to the positive results, partially offset by higher overall expenses, lower natural gas prices, and the effect of the $20.0 million differential in non-cash fair value adjustments associated with our commodity derivative contracts.

Our average production levels were 22% higher in the third quarter of 2007 than during the third quarter of 2006 and 14% higher in the first nine months of 2007 than during the first nine months of 2006, with significant increases in our tertiary oil and Barnett Shale production, partially offset by production declines in our Louisiana onshore properties. Our third quarter average production rate of 45,720 BOE/d was a Company quarterly record and 9% higher than our second quarter 2007 average production rate of 41,916 BOE/d. Higher oil prices further improved 2007 third quarter results as our average realized per BOE commodity price during that period was 9% higher than during the third quarter of 2006, resulting in 32% higher revenues in the 2007 third quarter period. The change in commodity prices on a per BOE basis was not a significant factor when comparing the respective first nine months, as our net per BOE average price increased only 1% as higher oil prices were almost entirely offset by lower natural gas prices. Revenues increased 15% in the 2007 first nine month period over the prior 2006 first nine month period.

Excluding any impact of our commodity derivative income and expense items discussed below, our aggregate expenses increased 33% during the third quarter of 2007 as compared to expenses during the third quarter of 2006 due to (i) higher overall industry costs, (ii) a higher percentage of operations related to tertiary operations (which generally have higher operating costs per BOE), (iii) the timing impact of the continued expansion of our tertiary operations in which we expense the cost of our $CO_2$ injections and other operating costs even though production response to the injections will lag behind (see Results of Operations $CO_2$ Operations for a more thorough discussion), (iv) significantly higher average debt levels to finance our $42 million acquisition on March 31, 2007 (see Recent Acquisition below) and continued spending in excess of cash flow from operations (see Capital Resources and Liquidity ), and (v) higher compensation expense resulting from additional employees and increased salaries which we consider necessary in order to remain competitive in the industry, partially offset by non-recurring charges to earnings in the third quarter of 2006 related to the retirement of our former Vice President of Marketing.

On a nine month basis, net income was $147.2 million during the first nine months of 2007, almost the same as the $147.3 million of net income earned during the first nine months of 2006. The higher production levels and $24.6 million of incremental net cash receipts on our derivative contracts in the 2007 period were offset by higher overall expenses and

**DENBURY RESOURCES INC.**

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

the effect of a $21.7 million differential in non-cash fair value adjustments primarily related to the 2007 natural gas derivative contracts.

During the first nine months of 2007, aggregate expenses (excluding commodity derivative income and expense) increased 28% overall with similar variances in all categories except for interest expense. Our interest expense increased significantly less on a nine month basis as compared to the third quarter variance because debt levels have steadily risen during 2007, reducing the percentage increase in debt levels on a nine month basis as compared to the third quarter percentage increase. Also, general and administrative expenses decreased slightly in the 2007 nine month period as the general increase in compensation costs during 2007 was more than offset by approximately $6.0 million in non-recurring charges to earnings in the first nine months of 2006 related to the departure and retirement of two vice presidents.

In addition to affecting our revenues, fluctuations in oil and natural gas prices also affected the market value of our derivative contracts. We recorded a $5.4 million (pre-tax) non-cash charge to income in the third quarter of 2007 for the fair value adjustment to our commodity derivative contracts, of which $3.0 million related to our natural gas swaps and $2.4 million to our oil swaps. During the third quarter of 2006, we recognized $14.6 million of income associated with these same fair value changes on our oil swaps as a result of the decline in oil prices late in the period. The impact of these non-cash fair value adjustments was a net decrease of $20.0 million in pre-tax income for the third quarter of 2007 as compared to 2006.

While overall costs were higher in the 2007 periods than in the comparable 2006 periods, during 2007 the rate of inflation in our industry appears to have moderated, and in some cases, we are beginning to see modest cost reductions. Likewise, although goods and services are still in tight supply, there have been signs of improvement in overall availability; but some supply issues persist, including long lead times for certain items, such as compressors used in our tertiary recycle facilities and construction services for pipelines. It is difficult to forecast price trends and supply and service availability, which if adverse, can significantly impact both operating costs and capital expenditures, as well as cause delays in achieving our anticipated production targets.

**Overview of tertiary operations.** Since we acquired our first carbon dioxide tertiary flood in Mississippi in 1999, we have gradually increased our emphasis on these types of operations. We particularly like this play because of its risk profile, rate of return and lack of competition in our operating area. Generally, from East Texas to Florida, there are no known significant natural sources of carbon dioxide except our own, and these large volumes of $CO_2$ that we own drive the play. Please refer to the section entitled $CO_2$ Operations below and contained in Management s Discussion and Analysis of Financial Condition and Results of Operations in our 2006 Form 10-K for further information regarding these operations, their potential, and the ramifications of this focus.

Oil production from our tertiary operations increased to an average of 16,101 BOE/d in the third quarter of 2007, a 59% increase over the third quarter 2006 tertiary production level of 10,114 BOE/d and an 18% increase over the second quarter 2007 tertiary production level. Production from our Phase II operations in eastern Mississippi (Soso, Eucutta and Martinville Fields) contributed 3,962 BOE/d (approximately two-thirds) to the increase over the prior year s third quarter production, with the balance of the increase coming from our Phase I fields, except Little Creek Field which is on a gradual decline.

**Agreement to sell Louisiana natural gas assets.** In October 2007, we announced that we had entered into an agreement to sell our Louisiana natural gas assets to a privately held company for approximately $180 million (before closing adjustments) plus any amounts received from a net profits interest. The sale is expected to close in early December 2007 and is subject to satisfactory completion of customary due diligence and closing conditions. The agreement contemplates an effective date of August 1, 2007, and consequently operating net revenue after August 1, net of capital expenditures, along with any other purchase price adjustments, will be accounted for as an adjustment to the ultimate sales price. The potential net profits interest relates to a sharing of production from a well in South Chauvin field if operating income from that well exceeds certain levels, which we believe could potentially increase the ultimate sales price by up to 10%.

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

Production attributable to the properties being sold averaged approximately 30.2 MMcfe/d (85% natural gas) during the third quarter of 2007, representing approximately 11% of our total third quarter production and approximately 4% of our total proved reserve quantities as of December 31, 2006.

**Recent Acquisition by Genesis Energy.** On July 25, 2007, Genesis Energy, L.P. ( Genesis ), a master limited partnership of which Denbury is the general partner, closed on a previously announced acquisition in which they acquired several energy related businesses from the Davison family of Ruston, Louisiana for total consideration of approximately $623 million (net of cash acquired at closing and subject to final purchase price adjustments). The acquisition agreement with the Davison s provided that Genesis deliver to them $560 million of consideration, half in common units at an agreed value of $20.8036 per unit (as compared to a value of $24.52 per unit for accounting purposes) and half in cash, subject to specified purchase price adjustments. These businesses include a trucking operation for petroleum products and other bulk commodities, terminal storage of refined petroleum products, a refinery service operation which processes sour gas streams at several refining operations, and a wholesale petroleum products marketing business. In conjunction with that acquisition, we exercised our right to maintain our pro rata (7.4%) ownership of common units, acquiring 1,074,882 additional common units for approximately $22.4 million, in addition to our capital contribution of an additional $6.2 million as general partner to maintain our 2% general partner s capital interest.

We have previously discussed with Genesis that upon Genesis achieving certain goals, primarily the acquisition of other economic projects that are not related to Denbury, that we would undertake to drop-down certain Denbury assets to Genesis based upon acquisition by Genesis of $1.50 of non-Denbury-related acquisitions for every $1.00 of asset sales from Denbury. These drop-down transactions are currently thought most likely to consist of pipeline property sales combined with associated transportation or service arrangements or direct financing leases, or a combination of these approaches. As a result of the recent Genesis acquisition, we currently anticipate that during the fourth quarter of 2007, we will enter into drop-down transactions with Genesis involving our existing $CO_2$ pipelines, with a total currently estimated value of between $200 million and $250 million. These drop-down transactions would be subject to, among other things, negotiation of specific terms, the approval of the board of directors of both entities, and the receipt of fairness opinions by both companies. Currently, we also anticipate similar transactions with Genesis for the new Delta $CO_2$ pipeline we are constructing from Jackson Dome to Tinsley and Delhi Fields once that pipeline is completed, forecasted at this time to be completed by the end of 2008. If in future periods Genesis is able to complete additional acquisitions of sufficient size with acceptable economic returns, and subject to the same types of conditions, we could possibly enter into similar transactions with Genesis with our proposed 300 mile $CO_2$ pipeline from Southern Louisiana to Hastings Field, located near Houston, Texas, probably during 2010.

**First Quarter 2007 Acquisition.** On March 30, 2007, we completed an acquisition of six producing oil and natural gas fields, two of which are future potential $CO_2$ tertiary oil flood candidates, collectively called the Seabreeze Complex, located near Houston, Texas, at a cost of approximately $39.4 million. Tertiary operations are not expected to commence at these fields until 2010 or 2011, following anticipated completion of the 300 mile $CO_2$ pipeline from Louisiana to Hastings Field (also near Houston). The acquisition was funded with bank financing under our existing credit facility. At the time of acquisition, these fields had estimated proved conventional reserves of approximately 525 MBOE and produced an average of 632 BOE/d during the third quarter of 2007. We operate all of these fields and own the majority of the working interests.

**April 2007 Debt Issuance.** On April 3, 2007, we issued $150 million of 7.5% Senior Subordinated Notes due 2015 as an additional issuance under our existing indenture governing our December 2005 sale of $150 million of 7.5% Senior Subordinated Notes due 2015. The notes were issued at 100.5% of par, which equates to an effective yield to maturity of 7.4%. The net proceeds from the issuance were approximately $149.2 million, which we used to repay a portion of the outstanding borrowings under our bank credit facility.

**Capital Resources and Liquidity**

Our current 2007 capital exploration and development budget is approximately $700 million, excluding any acquisitions we have made. In addition, through September 30, 2007, we had incurred approximately $44.7 million in oil and gas property acquisitions, primarily related to the Seabreeze acquisition (see Overview First Quarter 2007 Acquisition above), $9.4 million in $CO_2$ property acquisitions, and expended $28.6 million for additional Genesis LP and

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GP units (see Overview Recent Acquisition by Genesis Energy ), for total estimated capital expenditures of approximately $783 million. Based on oil and natural gas commodity futures prices as of the end of October 2007, our capital spending will be $225 million to $250 million greater than our anticipated cash flow from operations, a much greater shortfall than we have had in recent years. We plan to fund most, if not all, of this shortfall through a combination of (i) transactions with Genesis whereby we would drop-down our two existing significant $CO_2$ pipelines to them (see Overview Recent Acquisition by Genesis Energy ) and (ii) the sale of our Louisiana natural gas assets, if consummated (see Overview Agreement to sell Louisiana natural gas assets ), which should provide us with preliminary estimated after-tax net proceeds of approximately $160 million. If these transactions are all consummated before year-end, they could potentially leave us with no bank debt as of year-end and $125 million to $175 million of incremental cash.

As of October 31, 2007, we had $240 million of bank debt outstanding on a $500 million borrowing base, leaving us significant incremental borrowing capacity, more than we currently plan or desire to use, particularly considering the potential for significant cash proceeds later this year from the above contemplated transactions. Further, we believe that we could significantly increase our bank borrowing base if desired.

We have not finalized our 2008 capital budget, but preliminarily expect it to be approximately $900 million, excluding any potential acquisitions. The 2008 budget will be reviewed and finalized by our Board of Directors at our next regularly scheduled board meeting in December 2007. This preliminary 2008 program includes an estimated $245 million to acquire pipe and right-of-ways for our proposed $CO_2$ pipeline from Louisiana to Texas ( Green Pipeline ) and another $80 million for the $CO_2$ pipeline from Tinsley to Delhi Fields. The proposed Green Pipeline is expected to be constructed during 2009 at a preliminarily estimated additional cost of approximately $450 million. Preliminarily, over 50% of the remaining portion of our 2008 budget is expected to be spent on other tertiary related operations, over 25% in the Barnett Shale area, and the balance in other areas. Based on oil and natural gas commodity futures prices as of the end of October 2007 and preliminary 2008 production forecasts, our 2008 capital budget is forecasted to be $125 million to $175 million greater than our anticipated cash flow from operations. We currently plan to fund approximately $150 million of that shortfall through transactions with Genesis whereby we would drop-down our Delta $CO_2$ pipeline to them (see Overview Recent Acquisition by Genesis Energy ) and to fund most of the remaining balance with anticipated cash on hand at year-end 2007. Any shortfall in excess of these two sources would likely be funded with bank debt, which we expect to be zero at December 31, 2007. In addition, if commodity prices were to significantly decrease from current levels, we could also reduce our capital spending during 2008 in addition to using bank debt to fund the deficit.

We monitor our capital expenditures on a regular basis, adjusting them up or down depending on commodity prices and the resultant cash flow. Therefore, during the last few years as commodity prices have increased, we have increased our capital budget throughout the year. As a result of the recent cost inflation in our industry, many of our recent budget increases have related to escalating costs rather than additional projects. Even though there are signs that the rate of this inflationary trend is subsiding, if costs do rise or we spend more than our estimated or forecasted amounts, we will either have to increase our capital budget or consider deferring a portion of our planned projects.

We continue to pursue additional acquisitions of mature oil fields that we believe have potential as future tertiary flood candidates. These possible acquisitions are difficult to forecast and the purchase price can vary widely depending on the levels of existing production and conventional proved reserves and commodity prices. Any additional acquisitions would be funded, at least temporarily, with bank or other debt, although if significant, the acquisition would likely be ultimately funded with more permanent capital such as subordinated debt and/or additional equity.

**Amendment to our bank credit facility.** On March 31, 2007, we amended our Sixth Amended and Restated Credit Agreement with our nine banks, led by JPMorgan Chase Bank, N.A., as administrative agent. The amendment (i) increased the commitment amount that the banks are committed to fund from $250 million to $350 million, (ii) reconfirmed the borrowing base of $500 million, (iii) authorized the $150 million subordinated debt offering (see Overview April 2007 Debt Issuance ), and (iv) authorized us to enter into a sale-leaseback type transaction for our

$CO_2$ pipelines, not to exceed $300 million, with Genesis, in the type of transaction contemplated and discussed above (see Overview Recent Acquisition by Genesis Energy ). With regard to our bank credit facility, the borrowing base represents the amount that can be borrowed from a credit standpoint based on our assets, as confirmed by the banks, while

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the commitment amount is the amount the banks have committed to fund pursuant to the terms of the credit agreement. The banks have the option to participate in any borrowing request by us in excess of the commitment amount ($350 million), up to the borrowing base limit ($500 million), although the banks are not obligated to fund any amount in excess of the commitment amount. At October 31, 2007, we had outstanding $525 million (principal amount) of 7.5% subordinated notes and $240 million of bank debt.

*Sources and Uses of Capital Resources*

Capital Expenditure Summary

| | Nine Months Ended September 30, | |
|---|---|---|
| Amounts in thousands | 2007 | 2006 |
| Oil and gas exploration and development | | |
| Drilling | $ 248,718 | $ 164,598 |
| Geological, geophysical and acreage | 16,624 | 22,712 |
| Pipelines and facilities | 89,372 | 83,131 |
| Recompletions | 102,490 | 100,081 |
| Capitalized interest | 12,917 | 6,466 |
| Total oil and gas exploration and development expenditures | 470,121 | 376,988 |
| Oil and gas property acquisitions | 44,701 | 315,650 |
| Total oil and natural gas capital expenditures | 514,822 | 692,638 |
| $CO_2$ capital expenditures, including capitalized interest | 102,408 | 42,617 |
| Total | $ 617,230 | $ 735,255 |

Our 2007 capital expenditures have been funded with $364.8 million of cash flow from operations, $150.0 million from our issuance of subordinated debt in April, $96.0 million of net bank borrowings, and the balance funded with working capital. Adjusted cash flow from operations (a non-GAAP measure defined as cash flow from operations before changes in assets and liabilities as discussed below under Results of Operations Operating Results ) was $401.5 million for the first nine months of 2007, while cash flow from operations for the same period, the GAAP measure, was $364.8 million.

Our 2006 expenditures were funded with $344.3 million of cash flow from operations, $125 million of equity issued and $70 million of net bank borrowings and a $13 million increase in our accrued capital expenditures, with the balance funded with working capital, predominately cash from the December 2005 issuance of $150 million of subordinated debt.

**Off-Balance Sheet Arrangements**

*Commitments and Obligations*

Our obligations that are not currently recorded on our balance sheet consist of our operating leases and various obligations for development and exploratory expenditures arising from purchase agreements, our capital expenditure program, or other transactions common to our industry. In addition, in order to recover our proved undeveloped reserves, we must also fund the associated future development costs as forecasted in the proved reserve reports. Our derivative contracts, which are recorded at fair value in our balance sheets, are discussed in Note 6 to the Unaudited Condensed Consolidated Financial Statements. Neither the amounts nor the terms of these commitments or contingent obligations have changed significantly from the year-end 2006 amounts reflected in our Form 10-K filed on March 1, 2007, except for (i) a commitment to a new building lease expected to commence in mid-2008 representing future payments of approximately $20 million over 136 months, (ii) additional commitments discussed below to purchase anthropogenic (manufactured) $CO_2$ from proposed gasification plants, if they are built, and (iii) new commodity derivative natural gas swaps for 2008 (see Note 6).

We currently have long-term commitments to purchase manufactured $CO_2$ from three proposed gasification plants, if these plants are built, two proposed by the developers of Faustina Hydrogen Products LLC and another by Rentech Inc. If

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all three plants are built, these synthetic sources are currently anticipated to provide us with an aggregate of 750 MMcf/d to 850 MMcf/d of $CO_2$ by 2012. The base price of $CO_2$ per Mcf from these synthetic sources is currently expected to be 1.5 to 2.0 times higher than our most recent all-in cost of $CO_2$ from our natural sources (Jackson Dome) using current oil prices and assuming comparable compression levels. These predicted synthetic $CO_2$ prices are expected to be competitive with the cost of our natural $CO_2$ after adjusting for our share of potential carbon emissions credits using estimated current prices of $CO_2$ carbon credit futures. If all three plants are built, the aggregate purchase obligation for this $CO_2$ would be around $150 million per year, assuming a $60 per barrel oil price and comparable compression levels, before any potential savings from our share of carbon emissions credits. All of the contracts have price adjustments that fluctuate based on the price of oil. Construction has not yet commenced on any of these plants and their construction is contingent on the satisfactory resolution of various issues, including financing, although the initial Faustina plant (based upon their public disclosures to date) is currently scheduled to begin construction in late 2007 or early 2008, with completion scheduled in late 2010.

Please refer to Management s Discussion and Analysis of Financial Condition and Results of Operations Off-Balance Sheet Arrangements Commitments and Obligations contained in our 2006 Form 10-K for further information regarding our commitments and obligations.

**Results of Operations**

*$CO_2$ Operations*

Our focus on $CO_2$ operations is becoming an ever-increasing part of our business and operations. We believe that there are significant additional oil reserves and production that can be obtained through the use of $CO_2$, and we have outlined certain of this potential in our annual report and other public disclosures. In addition to its long-term effect, our focus on these types of operations impacts certain trends in our current and near-term operating results. Please refer to Management s Discussion and Analysis of Financial Condition and Results of Operations and the section entitled $CO_2$ Operations contained in our 2006 Form 10-K for further information regarding these matters.

During the remainder of 2007 and 2008 we plan to drill additional $CO_2$ source wells to further increase our production capacity and reserves. We estimate that we are currently capable of producing between 650 MMcf/d and 700 MMcf/d of $CO_2$. During the third quarter of 2007, our $CO_2$ production averaged 515 MMcf/d, as compared to an average of approximately 477 MMcf/d during the second quarter of 2007, and average production of 480 MMcf/d during the first nine months of 2007. We used 81% of this production, or 416 MMcf/d, in our tertiary operations during the third quarter of 2007, and sold the balance to our industrial customers or to Genesis pursuant to our volumetric production payments.

Oil production from our tertiary operations increased to an average of 16,101 BOE/d in the third quarter of 2007, a 59% increase over the third quarter 2006 tertiary production level of 10,114 BOE/d and an 18% increase over the second quarter 2007 tertiary production level of 13,683 BOE/d. The table below shows our tertiary oil production by field for the 2007 first three quarters and all four quarters of 2006. We saw continued improved response from our newer Phase II floods at Martinville, Eucutta and Soso Fields, most of which were initiated during 2006. In addition, we continue to see improved response at most of our other floods, except for Little Creek Field, which is a mature flood and is expected to continue to decline over the next several years.

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| Tertiary Oil Field | Average Daily Production (BOE/d) First Quarter 2006 | Second Quarter 2006 | Third Quarter 2006 | Fourth Quarter 2006 | First Quarter 2007 | Second Quarter 2007 | Third Quarter 2007 |
|---|---|---|---|---|---|---|---|
| Phase I: | | | | | | | |
| Brookhaven | 547 | 798 | 965 | 1,014 | 1,422 | 1,794 | 2,452 |
| Little Creek area | 3,006 | 3,056 | 2,623 | 2,279 | 2,117 | 1,974 | 2,011 |
| Mallalieu area | 5,219 | 5,385 | 5,243 | 4,994 | 5,470 | 5,802 | 5,823 |
| McComb area | 986 | 1,136 | 1,283 | 1,530 | 1,811 | 1,884 | 1,853 |
| Phase II: | | | | | | | |
| Martinville | | | | 24 | 320 | 521 | 1,101 |
| Eucutta | | | | 187 | 614 | 1,338 | 2,035 |
| Soso | | | | | 25 | 370 | 826 |
| Total tertiary oil production | 9,758 | 10,375 | 10,114 | 10,028 | 11,779 | 13,683 | 16,101 |

We spent approximately $0.21 per Mcf to produce our $CO_2$ during the first nine months of 2007, about the same as our average for the first nine months of 2006 of $0.20 per Mcf. Our estimated total cost per thousand cubic feet of $CO_2$ during the first nine months of 2007 was approximately $0.29, after inclusion of depreciation and amortization expense, the same as the 2006 nine month average. On a quarterly basis, we spent approximately $0.23 per Mcf to produce our $CO_2$ during the third quarter of 2007 and $0.20 per Mcf in the third quarter of 2006, with the higher cost in the 2007 period due to higher operating costs and higher oil costs which impacts the amount we pay royalty owners for the $CO_2$. Our estimated total cost per thousand cubic feet of $CO_2$ during the third quarter of 2007 was approximately $0.31, after inclusion of depreciation and amortization expense.

For the first nine months of 2007, our operating costs for our tertiary properties averaged $19.71 per BOE, higher than the prior year first nine months average of $16.73 per BOE, but slightly lower than our previous three quarters (fourth quarter 2006 through the second quarter of 2007) which all exceeded $20.00 per BOE, as the higher production more than offset the higher costs. Operating costs for our tertiary properties during the third quarter of 2007 were $18.65 per BOE. The higher costs are primarily due to general cost inflation in the industry, incremental $CO_2$ usage, higher fuel and energy costs and higher rental payments on leased equipment. Our single biggest expense, the cost of $CO_2$, almost doubled from $4.8 million in the third quarter of 2006 to $9.3 million during the third quarter of 2007 as a result of the 60% increase in $CO_2$ quantities utilized in our floods and the higher per unit cost of $CO_2$.

Since we expense all lease operating costs, including $CO_2$ injection costs, associated with starting a new flood, we expect the lease operating expense per BOE for tertiary operations to initially be high, until production increases significantly. For example, for the third quarter of 2007, operating costs per BOE for our Phase I properties, which are generally more developed than our Phase II properties, were $16.47 per BOE, as compared to tertiary operating costs of $23.40 per BOE for Phase II, an area which first responded in late 2006 and where response has increased significantly throughout 2007. In comparison, our operating costs for Mallalieu Field, currently our highest volume tertiary producer, was $9.84 per BOE during the same period. We expect our operating costs to average between $15.00 and $17.50 per BOE over the life of a tertiary flood, even though certain of our recent average tertiary operating costs have been higher. We have increased the upper end of the anticipated operating costs primarily to account for higher oil prices, which directly impact the cost of $CO_2$.

*Operating Results*

As summarized in the Overview section above and discussed in more detail below, for the third quarter of 2007, higher production and higher commodity prices, partially offset by non-cash expense associated with fair value adjustments for commodity derivative contracts and overall higher expenses, resulted in near-record quarterly earnings and a quarterly record cash flow from operations. On a nine month basis, higher production in the 2007 period was more than offset by a $21.7 million decrease between the respective periods in pre-tax income from non-cash fair value adjustments to derivative commodity contracts and overall higher expenses than in the first nine months of 2006.

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| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| Amounts in thousands, except per share amounts | 2007 | 2006 | 2007 | 2006 |
| Net income | $ 67,988 | $ 59,294 | $ 147,171 | $ 147,334 |
| Net income per common share basic | 0.56 | 0.50 | 1.23 | 1.27 |
| Net income per common share diluted | 0.54 | 0.48 | 1.17 | 1.20 |
| | | | | |
| Adjusted cash flow from operations (see below) | $ 166,776 | $ 118,983 | $ 401,496 | $ 355,625 |
| Net change in assets and liabilities relating to operations | 2,438 | 16,382 | (36,685) | (11,331) |
| | | | | |
| Cash flow from operations (1) | $ 169,214 | $ 135,365 | $ 364,811 | $ 344,294 |

(1) Net cash flow provided by operations as per the Unaudited Condensed Consolidated Statements of Cash Flows.

Adjusted cash flow from operations is a non-GAAP measure that represents cash flow provided by operations before changes in assets and liabilities, as calculated from our Unaudited Condensed Consolidated Statements of Cash Flows. Cash flow from operations is the GAAP measure as presented in our Unaudited Condensed Consolidated Statements of Cash Flows. In our discussion herein, we have elected to discuss these two components of cash flow provided by operations separately.

Adjusted cash flow from operations, a non-GAAP measure, is the cash flow earned or incurred from operating activities without regard to the collection or payment of associated receivables or payables. We believe it is important to consider adjusted cash flow from operations separately, as we believe it can often be a better way to discuss changes in operating trends in our business caused by changes in production, prices, operating costs, and related operational factors, without regard to whether the earned or incurred item was collected or paid during that year. We also use this measure because the collection of our receivables or payment of our obligations has not been a significant issue for our business, but merely a timing issue from one period to the next, with fluctuations generally caused by significant changes in commodity prices or significant changes in drilling activity. Adjusted cash flow from operations is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operations, investing, or financing activities, nor as a liquidity measure or indicator of cash flows.

The net change in assets and liabilities relating to operations is also important as it does require or provide additional cash for use in our business; however, we prefer to discuss its effect separately. For instance, as noted above, during the first nine months of 2007 and 2006, we used cash to fund a net increase in our other working capital items. During both periods this was caused by a larger increase in accrued production and trade and other receivables than the increase in our accounts payable and accrued liabilities. For the third quarters of 2007 and 2006, our net change in assets and liabilities generated cash flow for us as our accounts payable and accrued liabilities increased more than our accrued production and trade and other receivables.

Certain of our operating results and statistics for the comparative third quarters and first nine months of 2007 and 2006 are included in the following table:

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| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| **Average daily production volumes** | | | | |
| Bbls/d | 28,680 | 23,468 | 26,319 | 23,018 |
| Mcf/d | 102,239 | 84,557 | 94,129 | 82,912 |
| BOE/d [1] | 45,720 | 37,561 | 42,007 | 36,837 |
| **Operating revenues (in thousands)** | | | | |
| Oil sales | $ 190,685 | $ 138,172 | $ 459,995 | $ 387,731 |
| Natural gas sales | 57,528 | 49,626 | 174,831 | 165,014 |
| Total oil and natural gas sales | $ 248,213 | $ 187,798 | $ 634,826 | $ 552,745 |
| **Oil and gas derivative contracts [2] (in thousands)** | | | | |
| Cash receipt (payment) on settlements of derivative contracts | $ 9,414 | $ (2,207) | $ 19,384 | $ (5,187) |
| Non-cash fair value adjustment income (expense) | (5,441) | 14,582 | (27,269) | (5,597) |
| Total income (expense) from oil and gas derivative contracts | $ 3,973 | $ 12,375 | $ (7,885) | $ (10,784) |
| **Operating expenses (in thousands)** | | | | |
| Lease operating expenses | $ 59,323 | $ 42,225 | $ 167,087 | $ 120,148 |
| Production taxes and marketing expenses | 12,676 | 9,749 | 33,266 | 27,272 |
| Total production expenses [3] | $ 71,999 | $ 51,974 | $ 200,353 | $ 147,420 |
| **Non-tertiary $CO_2$ operating margin (in thousands)** | | | | |
| $CO_2$ sales and transportation fees [4] | $ 3,594 | $ 2,687 | $ 10,079 | $ 7,049 |
| $CO_2$ operating expenses | 1,304 | 842 | 3,211 | 2,272 |
| $CO_2$ operating margin | $ 2,290 | $ 1,845 | $ 6,868 | $ 4,777 |
| **Unit prices including impact of derivative settlements [2]** | | | | |
| Oil price per Bbl | $ 71.12 | $ 62.97 | $ 63.46 | $ 60.88 |
| Gas price per Mcf | 7.44 | 6.38 | 7.71 | 7.29 |
| **Unit prices excluding impact of derivative settlements [2]** | | | | |
| Oil price per Bbl | $ 72.27 | $ 64.00 | $ 64.02 | $ 61.70 |

| | | | | |
|---|---|---|---|---|
| Gas price per Mcf | 6.12 | 6.38 | 6.80 | 7.29 |
| **Oil and gas operating revenues and expenses per BOE (1)** | | | | |
| Oil and natural gas revenues | $ 59.01 | $ 54.35 | $ 55.36 | $ 54.96 |
| Oil and gas lease operating expenses | $ 14.10 | $ 12.22 | $ 14.57 | $ 11.95 |
| Oil and gas production taxes and marketing expense | 3.01 | 2.82 | 2.90 | 2.71 |
| Total oil and gas production expenses | $ 17.11 | $ 15.04 | $ 17.47 | $ 14.66 |

(1) Barrel of oil equivalent using the ratio of one barrel of oil to 6 Mcf of natural gas ( BOE ).

(2) See also Market Risk Management below for information concerning the Company s derivative transactions.

(3) Includes Transportation expense Genesis.

(4) Includes deferred revenue of $1.2 million for each of the three months ended September 30, 2007 and 2006, and $ 3.3 million and $3.2 million for the nine months ended September 30, 2007 and 2006, respectively, associated with a volumetric

production payment with Genesis. Includes transportation income from Genesis of $1.5 million and $1.3 million for the three months ended September 30, 2007 and 2006, respectively, and $3.8 million and $3.5 million for the nine months ended September 30, 2007 and 2006, respectively.

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**Production:** Production by area for each of the quarters of 2006 and the first, second, and third quarters of 2007 is listed in the following table.

| | Average Daily Production (BOE/d) | | | | | | |
|---|---|---|---|---|---|---|---|
| Operating Area | First Quarter 2006 | Second Quarter 2006 | Third Quarter 2006 | Fourth Quarter 2006 | First Quarter 2007 | Second Quarter 2007 | Third Quarter 2007 |
| Mississippi non-$CO_2$ floods | 12,455 | 12,633 | 13,069 | 12,808 | 12,738 | 12,525 | 12,131 |
| Mississippi $CO_2$ floods | 9,758 | 10,375 | 10,114 | 10,028 | 11,779 | 13,683 | 16,101 |
| Onshore Louisiana | 8,349 | 8,623 | 8,221 | 6,572 | 5,591 | 5,391 | 5,546 |
| Texas | 3,953 | 4,621 | 4,952 | 5,925 | 6,989 | 9,048 | 10,695 |
| Alabama and other | 939 | 1,222 | 1,205 | 1,286 | 1,208 | 1,269 | 1,247 |
| Total Company | 35,454 | 37,474 | 37,561 | 36,619 | 38,305 | 41,916 | 45,720 |

As outlined in the above table, production in the third quarter of 2007 increased 22% (8,159 BOE/d) over third quarter of 2006 levels, 9% over the second quarter 2007 levels, with production in the first nine months of 2007 increasing 14% over production in the first nine months of 2006. These increases from the 2006 periods are primarily due to increased production from our tertiary operations and the Barnett Shale, offset in part by decreases in our onshore Louisiana wells. The increase in our tertiary operations is discussed above under Results of Operations $CO_2$ Operations .

Production in the Mississippi non-$CO_2$ floods area decreased 7% from the prior year s third quarter and is down slightly from the second quarter of 2007 level, as this area is on a gradual decline from normal depletion, partially offset by drilling activity developing the Selma Chalk natural gas reservoir in the Heidelberg area.

The decrease in onshore Louisiana production in 2007 is due primarily to the expected relatively rapid depletion of wells in this area, although we had a slight production increase in this area between the second and third quarters of 2007 as a result of modest recent drilling success. Since 2005 we have focused less of our spending in this area and therefore drilled fewer wells than we have historically. We expect to close on the divesture of these assets, excluding any oil fields that could have tertiary oil potential, in December 2007 (See Overview Agreement to sell Louisiana natural gas assets ).

Our third quarter 2007 Texas Barnett Shale production increased approximately 103%, to 10,063 BOE/d, from third quarter of 2006 levels due to our successful drilling activity over the last year. During 2006, we drilled 46 horizontal wells and we drilled and completed 31 wells in the first nine months of 2007. We had four rigs working in the area during most of the first quarter of 2007, but in the second quarter reduced our rig count in this area to three, which we plan to retain for the remainder of 2007 and most likely during 2008. We believe that the third quarter of 2007 production has peaked, or is near its peak, from this area, based on the anticipated level of future drilling activity. The Texas property acquisition we made late in the first quarter of 2007 (see Overview Recent Acquisition ) contributed approximately 632 BOE/d to the third quarter 2007 production.

Our production for the third quarter of 2007 was weighted toward oil (63%), about the same as our proportion of oil production during the third quarter of 2006, as the recent increases in natural gas production in the Barnett Shale area, offset by declines in natural gas production in Louisiana, generally have been matched by increases in our tertiary oil production.

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**Oil and Natural Gas Revenues:** Oil and natural gas revenues for the third quarter of 2007 increased $60.4 million, or 32%, from revenues in the comparable quarter of 2006, as both commodity prices and production were higher. The increase in production in the third quarter of 2007 increased oil and natural gas revenues by $40.8 million, or 22%, while the increase in overall commodity prices in the third quarter of 2007 increased revenues by $19.6 million, or 10%, over the prior year s third quarter levels. When comparing the respective nine month periods, revenues increased $82.1 million, or 15%, primarily from higher production, as higher oil prices were almost offset by lower natural gas prices. The increase in production during the first nine months of 2007 increased revenues by $77.6 million, or 14%, while the slight increase in overall commodity prices during the first nine months of 2007 increased oil and natural gas revenues by $4.5 million, or 1% over the prior year s first nine months levels.

Excluding any impact of our derivative contracts, our net realized commodity prices and NYMEX differentials were as follows during the first, second and third quarters and first nine months periods of 2006 and 2007:

| | Three Months Ended March 31, | | Three Months Ended June 30, | | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 | 2007 | 2006 | 2007 | 2006 |
| **Net Realized Prices:** | | | | | | | | |
| Oil price per Bbl | $ 54.57 | $ 56.75 | $ 63.48 | $ 64.03 | $ 72.27 | $ 64.00 | $ 64.02 | $ 61.70 |
| Gas price per Mcf | 6.63 | 8.68 | 7.71 | 6.92 | 6.12 | 6.38 | 6.80 | 7.29 |
| Price per BOE | 49.06 | 55.01 | 57.02 | 55.54 | 59.01 | 54.35 | 55.36 | 54.96 |
| **NYMEX differentials:** | | | | | | | | |
| Oil per Bbl | $ (3.73) | $ (6.71) | $ (1.61) | $ (6.64) | $ (2.91) | $ (6.69) | $ (2.22) | $ (6.60) |
| Natural Gas per Mcf | (0.51) | 0.78 | 0.07 | 0.25 | (0.10) | 0.24 | (0.19) | 0.40 |

Our oil NYMEX differential during the second quarter of 2007 was the lowest in our corporate history. The improved NYMEX differential during 2007 was related to higher prices received for both our light sweet barrels and our sour barrels primarily as a result of NYMEX (WTI) prices being depressed due to lack of available storage capacity in the mid-continent area, an oversupply of crude from Canada, capacity/transportation issues in moving crude oil out of the Cushing, Oklahoma area and unanticipated refinery outages. This trend reversed itself by the end of the third quarter, for the most part, although the full impact of this reversal will not be demonstrated until the fourth quarter of 2007.

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

**Oil and Natural Gas Derivative Contracts:** During the first nine months of 2007, although we had significant fluctuations in our pre-tax income related to non-cash fair value adjustments in our oil and natural gas derivative contracts (expense of $35.2 million in the first quarter, income of $13.3 million in the second quarter and expense of $5.4 million in the third quarter) (see also Overview Results of Operations and Market Risk Management ), we had net positive cash receipts during each quarter in 2007 on the settlements of our commodity derivative contracts. We received approximately $8.3 million in net cash settlements during the first quarter of 2007, approximately $1.7 million during the second quarter, and approximately $9.4 million during the third quarter of 2007, all primarily related to our 2007 natural gas swaps, partially offset by payments on our oil swaps. In comparison, we paid out approximately $0.8 million during the first quarter of 2006, $2.2 million during the second quarter of 2006 and $2.2 million during the third quarter of 2006 related to our oil swaps in existence at that time.

**Production Expenses:** Our lease operating expenses increased between the comparable first nine months and third quarters on both a per BOE basis and in absolute dollars, primarily as a result of (i) our increasing emphasis on tertiary operations (see discussion of those expenses under $CO_2$ Operations above), (ii) higher overall industry costs, (iii) increased personnel and related costs, (iv) higher fuel and energy costs to operate our tertiary properties, (v) increasing

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lease payments for certain of our tertiary operating facilities, and (vi) higher workover costs. While absolute production expenses increased between the second and third quarters of 2007, our net cost per BOE decreased approximately 6% as the higher production more than offset the higher costs.

During the third quarter of 2007, operating costs averaged $14.10 per BOE, up from $12.22 per BOE in the third quarter of 2006. Operating expenses on our tertiary operations increased from $17.61 per BOE in the third quarter of 2006 to $18.65 per BOE during the third quarter of 2007, as a result of the higher cost of $CO_2$ and the increased number of tertiary floods in their initial stages (see $CO_2$ Operations above). Our emphasis on tertiary operations is expected to continue, which could further increase our cost per BOE as tertiary production becomes a more significant portion of our total production and operations. The trends were similar when comparing the respective first nine months of 2007 and 2006.

Production taxes and marketing expenses generally change in proportion to commodity prices and production volumes and therefore were higher in the third quarter of 2007 than in the comparable quarter of 2006. Transportation and plant processing fees were approximately $1.6 million higher in the third quarter of 2007 than in the third quarter of 2006 and approximately $4.8 million higher for the first nine months of 2007 than in the first nine months of 2006.

*General and Administrative Expenses*

General and administrative ( G&A ) expenses increased 9% between the respective third quarters and decreased 1% between the respective first nine months, as set forth below:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| Net G&A expense (thousands) | | | | |
| Gross G&A expenses | $ 28,412 | $ 23,910 | $ 83,554 | $ 72,505 |
| State franchise taxes | 705 | 662 | 2,163 | 1,355 |
| Operator labor and overhead recovery charges | (15,041) | (12,098) | (43,741) | (33,182) |
| Capitalized exploration and development costs | (2,535) | (1,875) | (7,307) | (5,638) |
| Net G&A expense | $ 11,541 | $ 10,599 | $ 34,669 | $ 35,040 |
| Average G&A cost per BOE | $ 2.74 | $ 3.07 | $ 3.02 | $ 3.48 |
| Employees as of September 30 | 668 | 558 | 668 | 558 |

Gross G&A expenses increased $4.5 million, or 19%, between the respective third quarters and $11.0 million and 15% between the respective first nine months. The increases are primarily due to higher compensation and personnel related costs caused by an increase in the number of employees, higher wages resulting from the 5% mid-year pay increase for all employees in mid-2006, and 2006 year-end pay increases which averaged 4.4%. During 2006, we increased our employee count by 30% and we further increased our employee count 12% in the first nine months of 2007. Partially offsetting these overall compensation increases was a $750,000 charge to earnings in the third quarter of 2006 related to the retirement of our former Vice President of Marketing and a $5.3 million charge to earnings in the second quarter of 2006 related to the modification of the vesting terms of certain restricted stock and stock options previously granted to our former Senior Vice President of Operations, associated with his departure from the Company. Stock compensation expense reflected in gross G&A expenses was approximately $3.2 million in the third quarter of 2007 and $9.3 million for the nine months ended September 30, 2007. Stock compensation expense, excluding the $6.0 million of non-recurring charges discussed above, was $3.1 million for the third quarter of 2006 and $9.9 million for the nine months ended September 30, 2006. Due to increased competitive pressures in the industry, our wages are increasing at a rate higher than general inflation and we expect this trend to continue. As such, we granted a 2% pay raise to all employees effective July 1, 2007.

The increase in gross G&A was offset in part by an increase in operator overhead recovery charges in the third quarter and first nine months of 2007. 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

**DENBURY RESOURCES INC.**

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

producing well. As a result of additional operated wells from acquisitions, additional tertiary operations, drilling activity during the past year and increased compensation expense, the amount we recovered as operator overhead charges increased by 24% between the third quarters of 2006 and 2007 and increased by 32% between the first nine months of 2006 and 2007. Capitalized exploration and development costs also increased by 35% between the third quarters of 2006 and 2007 and increased by 30% between the first nine months of 2006 and 2007, primarily as a result of increases in personnel and compensation costs.

The net effect was a 9% increase in net G&A expense between the respective third quarters and a 1% decrease between the first nine months of 2007 and 2006. On a per BOE basis, G&A costs decreased 11% in the third quarter of 2007 as compared to levels in the third quarter of 2006, and decreased 13% between the comparative first nine months of 2007 and 2006.

*Interest and Financing Expenses*

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| Amounts in thousands, except per BOE amounts | 2007 | 2006 | 2007 | 2006 |
| Cash interest expense | $ 13,743 | $ 8,456 | $ 35,954 | $ 24,902 |
| Non-cash interest expense | 316 | 284 | 890 | 852 |
| Less: Capitalized interest | (5,431) | (3,731) | (13,785) | (6,740) |
| Interest expense | $ 8,628 | $ 5,009 | $ 23,059 | $ 19,014 |
| Interest and other income | $ 1,702 | $ 1,716 | $ 5,269 | $ 5,119 |
| Average net cash interest expense per BOE (1) | $ 1.61 | $ 0.92 | $ 1.49 | $ 1.38 |
| Average interest rate (2) | 7.5% | 7.5% | 7.5% | 7.4% |
| Average debt outstanding | $ 736,596 | $ 452,638 | $ 640,916 | $ 447,813 |

(1) Cash interest expense, less capitalized interest, less interest and other income on a BOE basis.

(2) Includes commitment fees but excludes amortization of discount and debt issue costs.

Interest expense increased $3.6 million, or 72%, when comparing the third quarters of 2007 and 2006, and increased 21% for the nine months ended September 30, 2007 as compared to the prior year nine month period. Our average debt levels were significantly higher in the 2007 periods as our debt increased to fund acquisitions of properties in 2006 and 2007 and to fund our budgeted capital spending, which in 2007 is significantly in excess of our cash flow from operations (see also Capital Resources and Liquidity ). The increase in cash interest expense was partially offset by higher capitalized interest in the 2007 periods as indicated in the above table, due primarily to interest capitalized on our significant unevaluated properties acquired during 2006 and 2007.

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*Depletion, Depreciation and Amortization*

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| Amounts in thousands, except per BOE amounts | 2007 | 2006 | 2007 | 2006 |
| Depletion and depreciation of oil and natural gas properties | $ 47,347 | $ 36,681 | $ 124,290 | $ 98,197 |
| Depletion and depreciation of $CO_2$ assets | 2,966 | 2,371 | 8,408 | 6,051 |
| Asset retirement obligations | 746 | 677 | 2,232 | 1,863 |
| Depreciation of other fixed assets | 1,738 | 1,459 | 5,129 | 3,972 |
| Total DD&A | $ 52,797 | $ 41,188 | $ 140,059 | $ 110,083 |
| DD&A per BOE: | | | | |
| Oil and natural gas properties | $ 11.43 | $ 10.81 | $ 11.03 | $ 9.95 |
| $CO_2$ assets and other fixed assets | 1.12 | 1.11 | 1.18 | 1.00 |
| Total DD&A cost per BOE | $ 12.55 | $ 11.92 | $ 12.21 | $ 10.95 |

Our depletion, depreciation and amortization ( DD&A ) rate for oil and natural gas properties on a per BOE basis increased 6% between the respective third quarters and increased 11% between the respective first nine months, primarily due to capital spending and increased costs. We review our oil and natural gas reserves each quarter and adjust for significant increases or decreases in proved reserves. Our incremental reserve bookings in the third quarter of 2007 were not as significant as in the second quarter when we booked approximately 7.2 million barrels of incremental oil reserves related to our tertiary operations in Soso and Martinville Fields and 10.7 million BOEs of incremental reserves in our Barnett Shale area; however, because of the future capital costs associated with these additions, along with other capital spending and reclassification of costs into our full cost pool, the DD&A rate has not decreased. Our DD&A rate for our oil and natural gas properties has generally increased throughout 2007, averaging $11.43 per BOE in the third quarter of 2007, $10.94 per BOE in the second quarter of 2007 and $10.64 per BOE in the first quarter of 2007.

We allocated approximately $33.9 million of the $39.4 million adjusted purchase price of our March 30, 2007 Seabreeze acquisition to unevaluated properties to reflect the significant probable reserves from future tertiary flooding that we considered to be part of the acquisition. As a result, that acquisition did not materially affect our overall DD&A rate, as the amount included in our full cost pool was at a cost per BOE relatively consistent with our overall DD&A rate. We continually evaluate the performance of our other tertiary projects and if performance indicates that we are reasonably certain of recovering additional reserves from these floods, we recognize those incremental reserves in that quarter. Since we adjust our DD&A rate based on any changes in our estimates of oil and natural gas reserves and costs, our DD&A rate could change significantly in the future.

Our DD&A rate for our $CO_2$ and other general corporate fixed assets increased in the first nine months of 2007 as compared to the rate for the first nine months in 2006 as a result of costs incurred drilling $CO_2$ wells during the past year, putting the Free State $CO_2$ pipeline into service late in the first quarter of 2006, and higher future development costs, partially offset by an increase in $CO_2$ reserves from 4.6 Tcf as of December 31, 2005, to 5.5 Tcf as of December 31, 2006 (100% working interest basis before amounts attributable to Genesis volumetric production payments).

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*Income Taxes*

| Amounts in thousands, except per BOE amounts and tax rates | Three Months Ended September 30, 2007 | Three Months Ended September 30, 2006 | Nine Months Ended September 30, 2007 | Nine Months Ended September 30, 2006 |
|---|---|---|---|---|
| Current income tax expense | $ 5,197 | $ 5,419 | $ 14,158 | $ 12,856 |
| Deferred income tax expense | 38,028 | 30,251 | 79,609 | 80,110 |
| Total income tax expense | $ 43,225 | $ 35,670 | $ 93,767 | $ 92,966 |
| Average income tax expense per BOE | $ 10.28 | $ 10.32 | $ 8.18 | $ 9.24 |
| Effective tax rate | 38.9% | 37.6% | 38.9% | 38.7% |

Our income tax provision for the third quarter and first nine months of 2007 and 2006 was based on an estimated statutory tax rate of approximately 39%, adjusted for the impacts of certain items such as compensation arising from incentive stock options that cannot be deducted for tax purposes in the same manner as the book expense. In both periods, the current income tax expense represents our anticipated alternative minimum cash taxes that we cannot offset with enhanced oil recovery credits. As of December 31, 2006, we had an estimated $41.9 million of enhanced oil recovery credits to carry forward that we can utilize to reduce our current income taxes during 2007. We have not earned any additional credits since 2005 due to the high oil prices, which completely phased out our ability to earn any additional credits.

*Per BOE Data*

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

| Per BOE data | Three Months Ended September 30, 2007 | Three Months Ended September 30, 2006 | Nine Months Ended September 30, 2007 | Nine Months Ended September 30, 2006 |
|---|---|---|---|---|
| Oil and natural gas revenues | $ 59.01 | $ 54.35 | $ 55.36 | $ 54.96 |
| Gain (loss) on settlements of derivative contracts | 2.24 | (0.64) | 1.69 | (0.52) |
| Lease operating expenses | (14.10) | (12.22) | (14.57) | (11.95) |
| Production taxes and marketing expenses | (3.01) | (2.82) | (2.90) | (2.71) |
| Production netback | 44.14 | 38.67 | 39.58 | 39.78 |
| Non-tertiary $CO_2$ operating margin | 0.54 | 0.53 | 0.60 | 0.48 |
| General and administrative expenses | (2.74) | (3.07) | (3.02) | (3.48) |
| Net cash interest expense | (1.61) | (0.92) | (1.49) | (1.38) |
| Current income taxes and other | (0.68) | (0.78) | (0.66) | (0.04) |
| Changes in assets and liabilities relating to operations | 0.58 | 4.74 | (3.20) | (1.12) |
| Cash flow from operations | 40.23 | 39.17 | 31.81 | 34.24 |
| DD&A | (12.55) | (11.92) | (12.21) | (10.95) |
| Deferred income taxes | (9.04) | (8.75) | (6.94) | (7.97) |
| Non-cash commodity derivative adjustments | (1.29) | 4.22 | (2.38) | (0.56) |
| Changes in assets and liabilities and other non-cash items | (1.19) | (5.56) | 2.55 | (0.11) |
| Net income | $ 16.16 | $ 17.16 | $ 12.83 | $ 14.65 |

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

**Market Risk Management**

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. The following table presents the carrying and fair values of our debt, along with average interest rates. We had $230 million of bank debt outstanding as of September 30, 2007 and $134 million at December 31, 2006. The fair value of the subordinated debt is based on quoted market prices. None of our debt has any triggers or covenants regarding our debt ratings with rating agencies.

| | Expected Maturity Dates | | | Carrying | Fair |
|---|---|---|---|---|---|
| Amounts in thousands | 2009 | 2013 | 2015 | Value | Value |
| **Variable rate debt:** | | | | | |
| Bank debt | $ 230,000 | $ | $ | $ 230,000 | $ 230,000 |
| (The weighted-average interest rate on the bank debt at September 30, 2006 is 6.7%) | | | | | |
| **Fixed rate debt:** | | | | | |
| 7.5% subordinated debt due 2013 | $ | $ 225,000 | $ | $ 223,931 | $ 230,625 |
| (The interest rate on the subordinated debt is a fixed rate of 7.5%) | | | | | |
| 7.5% subordinated debt due 2015 | $ | $ | $ 300,000 | $ 300,707 | $ 307,500 |
| (The interest rate on the subordinated debt is a fixed rate of 7.5%) | | | | | |

From time to time, we enter into various oil and 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 and fixed price swaps. Historically, we hedged up to 75% of our anticipated production each year to provide us with a reasonably certain amount of cash flow to cover most of our budgeted exploration and development expenditures without incurring significant debt. Since 2005 and beyond, we have entered into fewer derivative contracts, primarily because of our strong financial position resulting from our lower levels of debt relative to our cash flow from operations. We did enter into natural gas derivative contracts in late 2006 and September 2007 as we believed that there is more risk with regard to natural gas prices and the fact that we planned to spend significantly more than we make during the ensuing year (see Capital Resources and Liquidity ). In late 2006 we swapped 80% to 90% of our forecasted 2007 natural gas production at a weighted average price of $7.96 per Mcf and in September of 2007, we swapped 70% to 80% of our remaining forecasted 2008 natural gas production (after the proposed sale of our Louisiana natural gas properties see Overview Agreement to sell Louisiana natural gas properties ) at a weighted average price of $7.91 per Mcf.

When we make a significant acquisition, we generally attempt to hedge a large percentage, up to 100%, of the forecasted proved production for the subsequent one to three years following the acquisition in order to help provide us with a minimum return on our investment. As of September 30, 2007, we had derivative contracts in place related to our $250 million acquisition that closed on January 31, 2006, on which we entered into contracts to cover 100% of the first three years of estimated proved producing production at the time we signed the purchase and sale agreement. While these derivative contracts related to the acquisition represent approximately 7% of our estimated 2007 production, they are intended to help protect our acquisition economics related to the first three years of production of the proved producing reserves that we acquired. These swaps cover 2,000 Bbls/d for 2007 at a price of $58.93 per Bbl; and 2,000 Bbls/d for 2008 at a price of $57.34 per Bbl.

At September 30, 2007, our derivative contracts were recorded at their fair value, which was a net liability of approximately $11.5 million, a decrease in value of approximately $27.2 million from the $15.7 million fair value asset recorded as of December 31, 2006. This change is the result of both the expiration of contracts during the first nine months of 2007 and the increases in both oil and natural gas commodity futures prices between December 31, 2006 and September 30, 2007.

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Based on NYMEX crude oil futures prices at September 30, 2007, oil prices were considerably higher than the swap prices of our outstanding derivative contracts so we would expect to make future cash payments of $18.0 million on our oil commodity hedges. If oil futures prices were to decline by 10%, the amount we would expect to pay under our oil commodity hedges would decrease to $10.9 million, and if futures prices were to increase by 10% we would expect to pay $25.1 million. Based on NYMEX natural gas futures prices at September 30, 2007, we would expect to receive cash payments of $4.7 million on our natural gas commodity hedges. If natural gas prices futures prices were to decline by 10%, we would expect to receive future cash payments of $27.2 million, and if futures prices were to increase by 10% we would expect to pay $17.7 million.

*Interest Rate Lock Contracts*

In January 2007, we entered into interest rate lock contracts to remove our exposure to possible interest rate fluctuations related to our commitment to the sale-leaseback financing of certain equipment for $CO_2$ recycling facilities at our tertiary oil fields. The interest rate lock contracts cover equipment currently being constructed that we have committed to finance with Bank of America Leasing & Capital LLC. This equipment has two estimated completion dates, one during the fourth quarter of 2007 and one during mid-year 2008, with a total estimated cost of approximately $15 million and $24 million, respectively. We are applying hedge accounting to these contracts as provided under SFAS No. 133.

At September 30, 2007, the interest rate locks were recorded at their fair value, which was a net liability of approximately $1.0 million. If the 5-year Semi-Annual Swap Rate were to increase or decrease 50-basis points, we would expect the fair value liability to change by approximately $0.9 million, with the increase in rates being a benefit to us and a decrease in rates being a liability to us.

**Critical Accounting Policies**

For a discussion of our critical accounting policies, which are related to property, plant and equipment, depletion and depreciation, oil and natural gas reserves, accounting for tertiary injection costs, asset retirement obligations, income taxes, stock compensation plans and hedging activities, and which remain unchanged, see Management s Discussion and Analysis of Financial Condition and Results of Operations in our annual report on Form 10-K for the year ended December 31, 2006.

**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 this 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 and Exchange Act of 1934, as amended, that involve a number of risks and uncertainties. Such forward-looking statements may be or may concern, among other things, forecasted capital expenditures, drilling activity or methods, acquisition plans and proposals and dispositions, development activities, cost savings, production rates and volumes or forecasts thereof, hydrocarbon reserves, hydrocarbon or expected reserve quantities and values, potential reserves from tertiary operations, hydrocarbon prices, pricing assumptions based upon current and projected oil and gas prices, liquidity, regulatory matters, mark-to-market values, competition, long-term forecasts of production, finding costs, rates of return, estimated costs, or changes in costs, future capital expenditures and overall economics and other variables surrounding our tertiary operations and future plans. Such forward-looking statements generally are accompanied by words such as plan, estimate, expect, predict, anticipate, projected, should, assume, believe, target 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 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 of the prices received or demand for the Company s oil and natural gas, inaccurate cost estimates, fluctuations in the prices of goods and services, the uncertainty of drilling results and reserve estimates, operating hazards, acquisition risks, requirements for capital or its availability, general economic conditions, competition and government regulations, unexpected delays, as well as the risks and uncertainties inherent in oil and gas drilling and production activities or which are otherwise discussed in this annual 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.

**Item 3. Quantitative and Qualitative Disclosures about Market Risk**

The information required by Item 3 is set forth under Market Risk Management in Management s Discussion and Analysis of Financial Condition and Results of Operations.

**Item 4. Controls and Procedures**

We maintain disclosure controls and procedures and internal controls designed to ensure that information required to be disclosed in our filings under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms. Our chief executive officer and chief financial officer have evaluated our disclosure controls and procedures as of the end of the period covered by this quarterly report on Form 10-Q and have determined that such disclosure controls and procedures are effective in ensuring that material information required to be disclosed in this quarterly report is accumulated and communicated to them and our management to allow timely decisions regarding required disclosure.

There have been no significant changes in internal controls over financial reporting during the period covered by this Quarterly Report on Form 10-Q that have materially affected, or are reasonably likely to materially affect, Denbury s internal controls over financial reporting.

## Part II. Other Information

**Item 1. Legal Proceedings**

Information with respect to this item has been incorporated by reference from our Form 10-K for the year ended December 31, 2006. There have been no material developments in such legal proceedings since the filing of such Form 10-K.

**Item 1A. Risk Factors**

Information with respect to the risk factors has been incorporated by reference from Item 1.A. of our Form 10-K for the year ended December 31, 2006. There have been no material changes to the risk factors since the filing of such Form 10-K.

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

**ISSUER PURCHASES OF EQUITY SECURITIES**

| Period | (a) Total Number of Shares Purchased | (b) Average Price Paid per Share | (c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs | (d) Maximum Number of Shares that May Yet Be Purchased Under the Plan Or Programs |
|---|---|---|---|---|
| July 1 through 31, 2007 | | | | |
| August 1 through 31, 2007 | 68,138 | $ 39.70 | | |
| September 1 through 30, 2007 | 3,528 | $ 42.10 | | |
| Total | 71,666 | $ 39.82 | | |

These shares were purchased from employees of Denbury who delivered shares to the company to satisfy their minimum tax withholding requirements related to the vesting of restricted shares.

## Item 3. Defaults Upon Senior Securities

None.

## Item 4. Submission of Matters to a Vote of Security Holders

None.

## Item 5. Other Information

None.

## Item 6. Exhibits

**Exhibits:**

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.

* Filed herewith.

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## SIGNATURES

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

**DENBURY RESOURCES INC.**
**(Registrant)**

By: /s/ Phil Rykhoek
Phil Rykhoek
Sr. Vice President and Chief Financial Officer

By: /s/ Mark C. Allen
Mark C. Allen
Vice President and Chief Accounting Officer

Dated: November 6, 2007