GOODRICH PETROLEUM CORP
Form 8-K
August 07, 2007

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

FORM 8-K
CURRENT REPORT
Pursuant to Section 13 or 15(d)
Of the Securities Exchange Act of 1934
Date of report (Date of earliest event reported): August 7, 2007
Commission file number: 001-7940
GOODRICH PETROLEUM CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**76-0466193**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

808 Travis, Suite 1320
Houston, Texas 77002
(Address of principal executive offices)

Registrant s telephone number, including area code: (713) 780-9494

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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ITEM 8.01. OTHER EVENTS.

On March 20, 2007, Goodrich Petroleum Company, L.L.C. (the Company) and Malloy Energy Company, L.L.C., a New York limited liability company collectively with the Company, (the Sellers) closed the sale of substantially all the Sellers assets located in South Louisiana to a private company (the Buyer) pursuant to the Purchase and Sale Agreement dated January 12, 2007 between the Sellers and Buyer. The entry into the Purchase and Sale Agreement was previously disclosed in the Company s Current Report on Form 8-K dated January 19, 2007 (the January 19, 2007 Current Report).

The sale resulted in total proceeds of $74 million, net to the Company, after normal closing adjustments. A detailed description of the assets sold to the Buyer can be found in the Purchase and Sale Agreement, which was filed as Exhibit 10.1 to the Company s January 19, 2007 Current Report, and this description is qualified in its entirety by reference to such exhibit.

The Company issued a press release on March 21, 2007, to announce the closing of the previously announced sale of substantially all of the Company s South Louisiana assets.

The Company reported operations with respect to these properties as discontinued operations in the Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2007.

This Current Report on Form 8-K was prepared to provide revised financial information that presents these sold properties and other properties held for sale as discontinued operations for all periods presented in the Company s Annual Report on Form 10-K for the year ended December 31, 2006, filed on March 14, 2007 (2006 Form 10-K). It should be noted that the Company s net income (loss) was not impacted by the reclassification of the company s operations with respect to these properties to discontinued operations.

Please note, the Company has not otherwise updated the financial information or business discussion for activities or events occurring after the date this information was presented in the Company s 2006 Form 10-K. You should read the Company s Quarterly Report on Form 10-Q for the period ended March 31, 2007 and Current Reports on Form 8-K and any amendments thereto, for updated information.

This filing includes updated information for the following items included in our 2006 Form 10-K:

ITEM 6. SELECTED FINANCIAL DATA

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Item 6. ***Selected Financial Data***

The following table sets forth our selected financial data and other operating information. The selected consolidated financial data in the table are derived from our consolidated financial statements. The financial statements reflect the sale, on March 20, 2007, of our South Louisiana properties as discontinued operations for each period presented. Discontinued operations in the years 2002, 2003 and 2004 also include the sale in October, 2004 of our West Texas properties. This data should be read in conjunction with the consolidated financial statements, related notes and other financial information included herein.

Statement of Operations Data:

	Year Ended December 31,				
	2006	2005	2004	2003	2002
	(In thousands, except per share amounts)				
Revenues:					
Oil and gas revenues	$ 73,933	$ 34,986	$ 3,759	$ 1,609	1,989
Other	838	325	151	477	131
	74,771	35,311	3,910	2,086	2,120
Operating Expenses					
Lease operating expense	13,182	3,821	347	507	2,690
Production taxes	2,851	1,809	164	90	122
Transportation	3,791	558			
Depreciation, depletion and amortization	37,225	12,214	1,486	900	2,663
Exploration	5,888	5,697	955	1,591	562
Impairment of oil and gas properties	9,886	340		335	342
General and administrative	17,223	8,622	5,821	5,314	4,468
(Gain) loss on sale of assets	(23)	(235)	(50)	66	(2,941)
	90,023	32,826	8,723	8,803	7,906
Operating income (loss)	(15,252)	2,485	(4,813)	(6,717)	(5,786)
Other income (expense):					
Interest expense	(7,845)	(2,359)	(1,110)	(1,051)	(985)
Gain (loss) on derivatives not qualifying for hedge accounting	38,128	(37,680)	2,317		
Loss on early extinguishment of debt	(612)				
	29,671	(40,039)	1,207	(1,051)	(985)
Income (loss) from continuing operations before income taxes	14,419	(37,554)	(3,606)	(7,768)	(6,771)
Income tax (expense) benefit	(5,120)	13,144	8,594	2,712	2,366
Income (loss) from continuing operations	9,299	(24,410)	4,988	(5,056)	(4,405)
Discontinued operations including gain on sale of assets, net of income taxes	(7,660)	6,960	13,539	8,978	3,454
	1,639	(17,450)	18,527	3,922	(951)

Income (loss) before cumulative effect of change in accounting principle					
Cumulative effect of change in accounting principle net of income taxes				(205)	
Net income (loss)	1,639	(17,450)	18,527	3,717	(951)
Preferred stock dividends	6,016	755	633	633	640
Preferred stock redemption premium	1,545				
Net income (loss) applicable to common stock	$ (5,922)	$ (18,205)	$ 17,894	$ 3,084	$ (1,591)
Income (loss) per common share from continuing operations:					
Basic	$ 0.37	$ (1.05)	$ 0.26	$ (0.28)	$ (0.25)
Diluted	$ 0.37	$ (1.05)	$ 0.25	$ (0.25)	$ (0.25)
Income (loss) per common share from discontinued operations:					
Basic	(0.31)	0.30	0.69	0.50	0.19
Diluted	(0.31)	0.30	0.66	0.44	0.19
Weighted average number of common shares outstanding:					
Basic	24,948	23,333	19,552	18,064	17,908
Diluted	25,412	23,333	20,347	20,482	17,908

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	Year Ended December 31,				
	2006	2005	2004	2003	2002
	(In thousands, except per share amounts)				
Balance Sheet Data:					
Total assets	$479,264	$296,526	$127,977	$89,182	$78,567
Total long-term debt	201,500	30,000	27,000	20,000	18,500
Stockholders equity	205,133	181,589	65,307	48,059	44,607

Item 7. *Management s Discussion and Analysis of Financial Condition and Results of Operation*s

Forward-Looking Statements

Certain statements in this report, including statements of the future plans, objectives, and expected performance of the Company, are forward-looking statements that are dependent upon certain events, risks and uncertainties that may be outside the Company s control, and which could cause actual results to differ materially from those anticipated. Some of these include, but are not limited to:

planned capital expenditures,

future drilling activity,

our financial condition,

business strategy,

the market prices of oil and gas,

economic and competitive conditions,

legislative and regulatory changes and

financial market conditions.

There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates. The drilling of exploratory wells can involve significant risks, including those related to timing, success rates and cost overruns. Lease and rig availability, complex geology and other factors can affect these risks. Although from time to time we make use of futures contracts, swaps, costless collars and fixed-price physical contracts to mitigate risk, fluctuations in oil and gas prices, or a prolonged continuation of low prices may substantially adversely affect the Company s financial position, results of operations and cash flows.

Overview

We are an independent oil and gas company engaged in the exploration, exploitation, development and production of oil and natural gas properties primarily in the Cotton Valley Trend of East Texas and Northwest Louisiana. We operate as one segment as each of our operating areas have similar economic characteristics and each meet the criteria for aggregation as defined in the Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) No. 131, *Disclosures about Segments of an Enterprise and Related Information* .

We seek to increase shareholder value by growing our oil and gas reserves, production revenues and operating cash flow. In our opinion, on a long term basis, growth in oil and gas reserves and production, on a cost-effective basis, are the most important indicators of performance success for an independent oil and gas company.

Management strives to increase our oil and gas reserves, production and cash flow through exploration and exploitation activities. We develop an annual capital expenditure budget which is reviewed and approved by our board of directors on a quarterly basis and revised throughout the year as circumstances warrant. We take into consideration our projected operating cash flow and externally available sources of financing, such as bank debt, when establishing our capital expenditure budget.

We place primary emphasis on our internally generated operating cash flow in managing our business. For this purpose, operating cash flow is defined as cash flow from operating activities as reflected in our Statement of Cash Flows. Management considers operating cash flow a more important indicator of our financial success than other traditional performance measures such as net income.

Our revenues and operating cash flow are dependent on the successful development of our inventory of capital projects, the volume and timing of our production, as well as commodity prices for oil and gas. Such pricing factors are largely beyond our control, however, we employ commodity hedging techniques in an attempt to minimize the volatility of short term commodity price fluctuations on our earnings and operating cash flow.

Cotton Valley Trend: Expanding Acreage Position and Active Development Drilling Program

Our relatively low risk development drilling program in the Cotton Valley Trend is primarily centered in and around Rusk, Panola, Angelina, Nacogdoches, Cherokee, Harrison, Smith and Upshur Counties, Texas and DeSoto, Caddo and Bienville Parishes, Louisiana. We continue to build our acreage position in the Cotton Valley Trend and now hold approximately 180,000 gross acres as of February 15, 2007. As of year end, we had drilled and/or logged a cumulative total of 156 Cotton Valley wells with a success rate slightly in excess of 99%. Our net production volumes from our Cotton Valley Trend wells aggregated approximately 29,964 Mcfe per day in 2006, or approximately 69% of our total oil and gas production in the period.

Acquisition of Remaining Interests in Dirgin-Beckville Area of Cotton Valley Trend

In early December 2006, we acquired a 14.5% working interest in 22 wells and approximately 3,300 gross (500 net) acres within the Dirgin-Beckville field in the Cotton Valley Trend from a private company for $6.1 million. With the additional interest we now own an approximate 99% working interest in 52 wells and 12,600 gross acres in this field.

Farmout on 21,200 acres in Northwest Louisiana

In November 2006, we announced a definitive farmout agreement covering 21,200 gross acres in 33 sections (16,000 net acres), in the Alabama Bend field of Bienville Parish, Louisiana. The Company has farmed in the right to explore for natural gas and oil at no upfront cost. The Company will own a 100% working interest in the initial well drilled in each of the 33 sections and the Farmor shall have the right to participate up to 50% for future wells drilled. To maintain the rights of the entire acreage block, we must commence drilling operations on one well every 90 days from completion date of the previous well.

Acquisition of Acreage in Angelina River Play in Nacogdoches and Angelina Counties, Texas

On February 7, 2007, we announced the acquisition of drilling and development rights in approximately 16,800 gross acres (8,380 net acres) in the Angelina River play, on trend with our existing acreage in Nacogdoches and Angelina Counties, Texas. We acquired a 60% working interest in the acreage and will operate the joint venture. The acquisition was completed in two separate transactions. In the initial transaction, we acquired a 40% interest for $2.0 million from a private company. We also agreed to carry the private company for a 20% interest in the drilling of five wells. In the second transaction, we purchased the remaining 20% interest in the acreage in a like-kind exchange for our 30% interest in the Mary Blevins field in Smith County, Texas.

South Louisiana Operations: 2007 Sale of Assets

On January 12, 2007, the Company and Malloy Energy Company, LLC (Malloy Energy) entered into a Purchase and Sale Agreement with a private company for the sale of substantially all of the Company s oil and gas properties in South Louisiana. The total sales price for the Company s interest in the oil and gas properties was approximately $100 million, effective July 1, 2006. The total sales price for Malloy Energy s interests in these properties was approximately $30 million with the same effective date. See Note 11 Related Party Transactions to our consolidated financial statements for additional information regarding Malloy Energy. Both the Company and Malloy Energy s total consideration was reduced by an amount equal to its proportionate share of the greater of $20 million or normal closing adjustments. The adjusted sales price for the Company s interest was $77 million. The effective date of the transaction was July 1, 2006 and the closing date of the sale was late March, 2007. Had we completed this transaction at the end of 2006, our proved reserves would have been reduced by approximately 31,700 MMcfe. Average daily production for these properties for the fiscal year-ending December 31, 2006, was approximately 12,904 Mcfe or about 30% of the Company s total production for 2006. This sale will allow us to focus the majority of our efforts on the development of our Cotton Valley Trend acreage, as well as reduce operating costs per unit of production going forward.

Overview of 2006 Results

2006 Financial and operating highlights include:

We increased our oil and gas production volumes on continuing operations 178 percent over 2005. Production averaged 30.5 MMcfe/d compared to 11.0 MMcfe/d in 2005.

Our 2006 oil and gas revenues for continuing operations totaled $73.9 million compared to $35.0 million in 2005, a 111 percent increase.

Net cash provided by operating activities increased $19.6 million from 2005, to $65.1 million.

Estimated proved reserves grew 19 percent to approximately 206.2 Bcfe (approximately 187.0 Bcf of natural gas and 3.2

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MMBbls of oil and condensate), with a pre-tax present value of future net cash flows, discounted at 10%, of $214.2 million and an after-tax present value of discounted future net cash flows of $200.3 million.

Capital expenditures totaled $269.4 million in 2006, versus $164.6 million in 2005.

As operator, we successfully drilled, completed and placed in production 101 wells during calendar year 2006.

We issued $175.0 million in 3.25% convertible senior notes due 2026, completely paying off our Second Lien Term Loan and substantially reducing our bank revolver debt.

Summary Operating Information:

	Year Ended December 31,				Year Ended December 31,			
	2006	2005	Variance		2005	2004	Variance	
	(in thousands, except for price data)							
Net Production-Continuing Operations:								
Natural gas (MMcf)	10,500	3,786	6,714	177%	3,786	408	3,378	828%
Oil and gas condensate (MBbls)	106	38	68	179%	38	33	5	15%
Total (Mmcfe)	11,135	4,012	7,123	178%	4,012	608	3,404	560%
Average daily production (Mmcfe/d)	30,507	10,990	19,517	178%	10,990	1,661	9,329	562%
Net Production-Discontinued Operations:								
Natural gas (MMcf)	2,501	2,451	50	2%	2,451	4,410	(1,959)	(44%)
Oil and gas condensate (MBbls)	368	370	(2)	(1%)	370	442	(72)	(16%)
Total (Mmcfe)	4,710	4,674	36	1%	4,674	7,060	(2,386)	(34%)
Average daily production (Mmcfe/d)	12,904	12,805	99	1%	12,805	19,289	(6,484)	(34%)
Revenues- Continuing Operations:								
Natural Gas	$ 67,372	$ 33,015	$ 34,357	104%	$ 33,015	$ 2,573	$ 30,442	1183%
Oil and condensate	6,561	1,971	4,590	233%	1,971	1,186	785	66%
Natural gas, oil and condensate	73,933	34,986	38,947	111%	34,986	3,759	31,227	831%
Operating revenues	74,771	35,311	39,460	112%	35,311	3,910	31,401	803%
Operating expenses	90,023	32,826	57,197	174%	32,826	8,723	24,103	276%
Operating income (loss)	(15,252)	2,485	(17,737)	(714%)	2,485	(4,813)	7,298	(152%)
Net Income (loss) applicable to common stock	$ (5,922)	$(18,205)	$ 12,283	(67%)	$(18,205)	$17,894	$(36,099)	(202%)

Average Realized Sales price Per Unit From Continuing Operations:								
Average realized price (per Mcf)	6.42	8.72	(2.30)	(26%)	8.72	6.31	2.41	38%
Average realized price (per Bbl)	62.03	52.47	9.56	18%	52.47	35.58	16.89	47%
Average realized price (per Mcfe)	$ 6.64	$ 8.72	$ (2.08)	(24%)	$ 8.72	$ 6.18	$ 2.54	41%

Results of Operations

The financial statements include discontinued operations presentation for our assets located in South Louisiana. See Note 12 Acquisitions and Divestures to our consolidated financial statements.

Operating Income

Year ended December 31, 2006 compared to year ended December 31, 2005

Operating revenues from continuing operations increased 112% or $39.5 million to a total of $74.8 million in 2006 compared to 2005. The increase resulted from an 178% increase in production volumes. The drilling, completion and placing into production of 101 operated wells in the Cotton Valley Trend led to natural gas production more than doubling in 2006. The average realized price for natural gas fell in 2006 by 26% to $6.42 per Mcf. The average realized oil price was strong in 2006, increasing 18% to $62.03 per Bbl.

Year ended December 31, 2005 compared to year ended December 31, 2004

Operating revenues from continuing operations increased 803% or $31.4 million in 2005 compared to 2004. This increase resulted from an increase in oil and gas production volumes, due to a substantial increase in Cotton Valley Trend production, as well as higher average oil and gas prices. We placed 45 Cotton Valley Trend wells on production in 2005. Initial production from the Cotton Valley Trend commenced in June 2004 and we ended 2004 with 11 wells on production.

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Operating Expenses per Mcfe From Continuing Operations:

	Year Ended December 31,				Year Ended December 31,			
	2006	2005	Variance		2005	2004	Variance	
Lease operating expense	$1.18	$0.95	$ 0.23	24%	$0.95	$0.57	$ 0.38	67%
Production taxes	0.26	0.45	(0.19)	(42%)	0.45	0.27	0.18	67%
Transportation	0.34	0.14	0.20	143%	0.14		0.14	
Depreciation, depletion and amortization	3.34	3.04	0.30	10%	3.04	2.44	0.60	25%
Exploration	0.53	1.42	(0.89)	(63%)	1.42	1.57	(0.15)	(10%)
Impairment of oil and gas properties	0.89	0.08	0.81	1013%	0.08		0.08	
General and administrative	1.55	2.15	(0.60)	(28%)	2.15	9.57	(7.42)	(78%)

Operating Expenses

Year ended December 31, 2006 compared to year ended December 31, 2005

Lease operating expense (LOE) was $13.2 million for 2006 compared to $3.8 million for 2005. Given the rapid pace of our development program in the Cotton Valley Trend in 2006, we experienced significant increases in two major components of LOE, salt water disposal costs ($4.1 million) and compressor rental expense ($2.9 million). With the planned installation of our low pressure gathering system in this region, we expect to see a decline in the per unit LOE charges in 2007. Higher workover activity also contributed to a higher cost per Mcfe in 2006. The majority of this activity occurred during the fourth quarter.

Production taxes were $2.9 million for 2006 versus $1.8 million in 2005. The reduction in production taxes per Mcfe resulted from rebates approved by the State of Texas of $1.3 million. These severance tax rebates relate to a number of our wells which have been approved as high cost tight gas sand wells, allowing us to pay a lower severance tax rate for up to 10 years following certification by the State.

Transportation expense was $3.8 million for 2006 compared to $0.6 million for 2005. The significant increase in transportation expense was due to the requirement for longer transportation segments in our Cotton Valley Trend properties. As our volumes from the Cotton Valley Trend expanded over 181% during 2006, our transportation expense increased accordingly.

Depletion, depreciation and amortization expense (DD&A) was $37.2 million for the year ended December 31, 2006, versus $12.2 million for the year ended December 31, 2005, with the increase due to higher production volumes and higher DD&A rates. The higher rates are a result of an increase in capitalized development costs.

Exploration expense for the year ended December 31, 2006, was $5.9 million versus $5.7 million for the year ended December 31, 2005. Leasehold amortization was $4.8 million versus $2.8 million in 2005.

We recorded an impairment expense of $9.9 million in the year ended December 31, 2006, all of it being determined in conjunction with the receipt of the independent engineer s final report on reserves as of that date. Of the total expense, $8.4 million related to two fields in East Texas which were not a part of the Company s primary Cotton Valley Trend acreage position, and the remaining $1.5 million was spread among several minor properties.

General and administrative (G&A) expenses increased to $17.2 million for the year ended December 31, 2006, from $8.6 million for the year ended December 31, 2005. Stock-based compensation, which consists of the amortization of restricted stock awards and expense associated with our stock option plan, increased to $6.0 million for the year ended December 31, 2006, compared to $1.4 million in 2005. We adopted SFAS 123R on January 1, 2006. SFAS 123R requires new, modified and unvested share-based payment transactions with employees to be measured at fair value and recognized as compensation expense over the requisite service period. See Note 2 Stock-Based Compensation to our consolidated financial statements for additional information.

Year ended December 31, 2005 compared to year ended December 31, 2004

Lease operating expense was $3.8 million for the year ended December 31, 2005 versus $0.3 million for the year ended December 31, 2004, with the increase primarily due to an increase in Cotton Valley Trend production volumes.

Production taxes were $1.8 million for the year ended December 31, 2005 compared to $0.2 million for the year ended December 31, 2004, due to an increase in Cotton Valley Trend production volumes and product prices.

DD&A was $12.2 million for the year ended December 31, 2005, versus $1.5 million for the year ended December 31, 2004, with the increase due to higher production volumes and higher DD&A rates. The higher rates are a result of an increase in capitalized development costs.

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Exploration expense for the year ended December 31, 2005 was $5.7 million versus $1.0 million for the year ended December 31, 2004, primarily due to increased dry hole costs from an exploratory well drilled in East Baton Rouge Parish, Louisiana, and higher non-producing leasehold amortization expense associated with the expansion of our Cotton Valley Trend acreage position.

We recorded an impairment expense of $0.3 million in the recorded value of one property for the year ended December 31, 2005, due to sooner than anticipated depletion of reserves.

G&A increased to $8.6 million for the year ended December 31, 2005, from $5.8 million for the year ended December 31, 2004. This increase was primarily due to higher compensation related costs due to an approximate 25% increase in the number of employees in 2005 and professional fees related to the implementation of the requirements of Section 404 of the Sarbanes-Oxley Act of 2002. Stock-based compensation, which consists of the amortization of restricted stock awards, increased to $1.1 million for the year ended December 31, 2005, compared to $0.6 million for the comparable period in 2004 due to the vesting of awards previously granted.

	Year Ended December 31,		
	2006	**2005**	**2004**
		(in thousands)	
Other income (expense):			
Interest Expense	$ (7,845)	$ (2,359)	$ (1,110)
Gain (loss) on derivatives not qualifying for hedge accounting	38,128	(37,680)	2,317
Loss on early extinguishment of debt	(612)		
Income tax (expense) benefit	(5,120)	13,144	8,594
Income (loss) from discontinued operations, net of tax	(7,660)	6,960	13,539
Average total borrowings	$99,542	$ 30,417	$22,958
Weighted average interest rate	7.5%	7.0%	3.8%

Other Income (Expense)

Year ended December 31, 2006 compared to December 31, 2005

Interest expense was $7.8 million for 2006, compared to $2.4 million for 2005, with the increase primarily attributable to a higher level of average borrowings in 2006.

Gain on derivatives not qualifying for hedge accounting relates to our ineffective gas hedges for the entire year and for our ineffective oil hedges for the fourth quarter, and amounted to $38.1 million for the year ended December 31, 2006, compared to a loss of $37.7 million for the year ended December 31, 2005. The gain in 2006 includes an unrealized gain of $40.2 million in the mark to market value of our ineffective gas and oil hedges and a realized loss of $2.1 million for the effect of settled derivatives on our ineffective gas and oil hedges. Our natural gas hedges were ineffective again in 2006, and certain oil hedges were deemed ineffective in the fourth quarter of 2006 thereby rendering all of our commodity derivatives ineffective. For these ineffective hedges, we are required to reflect the changes in the fair value of the hedges in earnings rather than in accumulated other comprehensive loss, a component of stockholders equity. As applied to our hedging program, there must be a high degree of correlation between the actual prices received and the hedge prices in order to justify treatment as cash flow hedges pursuant to SFAS 133. We perform historical correlation analyses of the actual and hedged prices over an extended period of time. In the fourth quarter of 2006, we determined that certain of our oil hedges which had previously been effective, fell short of the effectiveness guidelines to be accounted for as cash flow hedges. To the extent that our hedges are deemed to be ineffective in the future, we will be exposed to volatility in earnings resulting from changes in the fair value of our hedges.

We fully paid off our Second Lien Term loan in early December 2006 with the proceeds of the 3.25% convertible senior notes offering. In the fourth quarter of 2006, we wrote off remaining deferred loan financing costs of $0.6 million which resulted from the initial funding of this loan and a subsequent amendment.

Income tax expense on continuing operations of $5.1 million which was non-cash represents 35.5% of the pre-tax income in 2006. Income tax benefit of $13.1 million in 2005 represents 35% of pre-tax loss in 2005. The net deferred tax asset as of December 31, 2006, is expected to be realized based upon expected utilization of tax net operating loss carryforwards and the projected reversal of temporary differences.

Loss, net of tax on discontinued operations was $7.7 million for the year ended December 31, 2006 compared to income, net of tax on discontinued operations of $7.0 million for the year ended December 31, 2005, representing substantially all of our oil and gas properties sold or held for sale in South Louisiana. See Note 12 Acquisitions and Divestitures to our consolidated financial statements for a further discussion of our discontinued operations.

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Year ended December 31, 2005 compared to year ended December 31 2004

Interest expense was $2.4 million for the year ended December 31, 2005, compared to $1.1 million for the year ended December 31, 2004, with the increase primarily attributable to a higher level of average borrowings in 2005 and a higher total interest rate.

Loss on derivatives not qualifying for hedge accounting relates to our ineffective gas hedges and amounted to $37.7 million for the year ended December 31, 2005, compared to a gain of $2.3 million for the year ended December 31, 2004. The loss in 2005 is related to the change in fair value of our ineffective gas hedges. Since our natural gas hedges were deemed ineffective, beginning in the fourth quarter of 2004, we have been required to reflect the changes in the fair value of our natural gas hedges in earnings rather than in accumulated other comprehensive loss, a component of stockholders equity. In the fourth quarter of 2004, we initially determined that our gas hedges fell short of the effectiveness guidelines to be accounted for as cash flow hedges and, likewise, made the same determination in each of the four quarters of 2005.

Income taxes from continuing operations were benefits of $13.1 million and $8.6 million for the years ended December 31, 2005 and 2004, respectively, representing 35% of the pre-tax losses and the $7.3 million revision of the deferred tax valuation allowance in 2004.

Income net of tax from discontinued operations was $7.0 million for the year ended December 31, 2005 compared to income net of tax from discontinued operations of $13.5 million for the year ended December 31, 2004. Income net of tax from discontinued operations for 2004 consisted of $12.8 million from operations of our oil and gas properties in South Louisiana and $0.7 million from the after-tax gain realized on the sale of our operated interests in the Marholl and Sean Andrew fields, along with our non-operated interests in the Ackerly field, all of which were located in West Texas.

Liquidity and Capital Resources

Our principal requirements for capital are to fund our exploration and development activities and to satisfy our contractual obligations. These obligations include the repayment of debt and any amounts owing during the period relating to our hedging positions. Our uses of capital include the following:

- Drilling and completing new natural gas and oil wells;
- Constructing and installing new production infrastructure;
- Acquiring and maintaining our lease position, specifically in the Cotton Valley Trend;
- Plugging and abandoning depleted or uneconomic wells.

Our capital budget for 2007 is $275 million. We continue to evaluate our capital budget throughout the year.

Future commitments

The table below provides estimates of the timing of future payments that we are obligated to make based on agreements in place at December 31, 2006. See Note 4, Long-Term Debt and Note 10, Commitments and Contingencies to our consolidated financial statements for additional information.

Payments Due by Period

	Note	Total	2007	2008	2009	2010	2011	After 2011
				(in thousands)				
Contractual Obligations								
Long term debt (1)	4	$ 201,500	$	$	$	$ 26,500	$ 175,000	$
Operating lease for office space	10	1,992	701	710	491	48	42	
Drilling rig commitments	10	80,247	45,983	24,956	9,308			

Transportation contracts	10	2,159	758	540	540	321		
Total contractual obligations (2)		$ 285,898	$ 47,442	$ 26,206	$ 10,339	$ 26,869	$ 175,042	$

(1) The $175.0 million convertible senior notes have a provision at the end of years 5, 10 and 15, for the investors to demand payment on these dates; the first such date is December 1, 2011.

(2) This table does not include the estimated liability for dismantlement, abandonment and restoration costs of oil and gas properties of $9.6 million. The Company records a separate liability for the fair value of this asset retirement obligation. See Note 3, Asset Retirement Obligation to our consolidated financial statements.

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Capital Resources

We intend to fund our capital expenditure program, contractual commitments, including settlement of derivative contracts and future acquisitions with cash flows from our operations, borrowings under our revolving bank credit facility and the proceeds from the 2007 sale of South Louisiana properties. In the future, we may also access public markets to issue additional debt and/or equity securities.

At December 31, 2006, we had $123.5 million of excess borrowing capacity under our revolving bank credit facility. Our primary sources of cash during 2006 were from funds generated from operations, bank borrowings and proceeds received from the issuance of $175.0 million of convertible notes in December 2006. Cash was used primarily to fund exploration and development expenditures. During 2006 we made aggregate cash payments of $7.3 million for interest. There were no payments made in 2006 for federal income taxes. The table below summarizes the sources of cash during 2006, 2005 and 2004:

	Year Ended December 31,			Year Ended December 31,		
Cash flow statement information:	2006	2005	Variance	2005	2004	Variance
			(in thousands)			
Net cash:						
Provided by operating activities	$ 65,133	$ 45,562	$ 19,571	$ 45,562	$ 41,028	$ 4,534
Used in investing activities	(258,737)	(163,571)	(95,166)	(163,571)	(45,414)	(118,157)
Provided by financing activities	179,946	134,402	45,544	134,402	6,346	128,056
Increase(decrease) in cash and cash equivalents	$ (13,658)	$ 16,393	$ (30,051)	$ 16,393	$ 1,960	$ 14,433

At December 31, 2006, we had a working capital deficit of $22.2 million and long-term debt of $201.5 million. The working capital deficit was due to the typical timing difference between the expenditure of funds and accruals resulting from drilling and completion activities.

Cash Flows

Year ended December 31, 2006 compared to year ended December 31, 2005

Operating activities. Cash flow from operations is dependent upon our ability to increase production through development, exploration and acquisition activities and the price of oil and natural gas. Our cash flow from operations is also impacted by changes in working capital. Net cash provided by operating activities increased to $65.1 million, up 43% from $45.6 million in 2005. As previously mentioned, the 112% increase in operating revenues due to higher production volumes from our continuing operations drove the increased cash flow in 2006. Operating cash flow amounts are net of changes in our current assets and current liabilities, which resulted in increases of $4.9 million and $13.2 million for the years ended December 31, 2006 and 2005, respectively.

Investing activities. Net cash used in investing activities was $258.7 million for the year ended December 31, 2006, compared to $163.6 million for 2005. Of the $258.7 million, approximately $211.0 million was spent for drilling and completion activities in the Cotton Valley Trend, versus $139.9 million in 2005.

Financing activities. Net cash provided by financing activities was $179.9 million in 2006 versus $134.4 million in 2005. The majority of our net financing cash flows came from the $175.0 million in convertible note proceeds, and the $29.0 million in convertible preferred proceeds received in 2006.

Year ended December 31, 2005 compared to year ended December 31, 2004

Operating activities. Net cash provided by operating activities increased to $45.6 million, up 11% from $41.0 million in 2004. The increases in 2005 were a result of the increases in natural gas and crude oil prices and production levels in 2005 compared to 2004, partially offset by increases in lease operating expenses, exploration expenses and general and administrative expenses. Including the effect of settled derivatives, sales of oil and gas increased $31.2 million in 2005 compared to 2004, with realized crude oil and natural gas prices and production volumes both increasing in 2005 compared to 2004. Operating cash flow amounts are net of changes in our current assets and current liabilities, which resulted in increases to our operating cash flow in the amounts of $13.2 million and $14.1 million, respectively, in the years ended December 31, 2005 and 2004, reflecting increased revenue and expenditure activity associated with our Cotton Valley Trend wells.

Investing activities. Net cash used in investing activities was $163.6 million for the year ended December 31, 2005, compared to $45.4 million for the year ended December 31, 2004. For the year ended December 31, 2005, capital expenditures totaled $164.6

million primarily due to development on our Cotton Valley Trend wells, which accounted for 85% of the capital costs incurred in 2005. For the year ended December 31, 2004, capital expenditures totaled $47.5 million, as we incurred substantial drilling and leasehold acquisition costs in East Texas and Northwest Louisiana and participated in the drilling of two successful exploratory wells and one successful sidetrack well in the Burrwood/West Delta 83 field. Offsetting these capital expenditures were sales of non-core properties in West Texas and another minor property in the total amount of $2.1 million.

Financing activities. Net cash provided by financing activities was $134.4 million for the year ended December 31, 2005, compared to $6.4 million for the year ended December 31, 2004. In May 2005, we completed a public offering of 3,710,000 shares of our common stock resulting in net proceeds of $53.1 million which was used to repay all then outstanding indebtedness to BNP under a senior credit facility. On December 21, 2005, we issued and sold 1,650,000 shares of our Series B Convertible Preferred Stock for net proceeds as well as bank borrowings of approximately $79.8 million through a private placement.

Our senior credit facility and term loan include certain financial covenants with which we were in compliance as of December 31, 2006. We do not anticipate a lack of borrowing capacity under our senior credit facility or term loan in the foreseeable future due to an inability to meet any such financial covenants nor a reduction in our borrowing base.

3.25% Convertible Senior Notes

In early December 2006, we issued $125.0 million in convertible senior notes. The intial purchasers option was exercised in full and increased the principal amount to $175.0 million. The notes mature on December 1, 2026, unless earlier converted, redeemed or repurchased. The notes will be our senior unsecured obligations and will rank equally in right of payment to all of our other existing and future indebtedness. The notes accrue interest at a rate of 3.25% annually and paid semi-annually on June 1 and December 1 beginning June 1, 2007. Prior to December 1, 2011, the notes will not be redeemable. On or after December 11, 2011, we may redeem for cash all or a portion of the notes, and the investors may require us to repay the notes on each of December 11, 2011, 2016 and 2021. The notes are convertible into shares of our common stock at a rate equal to the sum of:

a) 15.1653 shares per $1,000 principal amount of notes (equal to a base conversion price of approximately $65.94 per share) plus,

b) an additional amount of shares per $1,000 of principal amount of notes equal to the incremental share factor (2.6762), multiplied by a fraction, the numerator of which is the applicable stock price less the base conversion price and the denominator of which is the applicable stock price.

Share Lending Agreement

With the offering of the 3.25% convertible senior notes we agreed to lend an affiliate of Bear, Stearns & Co. (BSC) a total of 3,122,263 shares of our common stock. The shares of stock were lent to the affiliate of BSC under the Share Lending Agreement. Under this agreement, BSC is entitled to offer and sell such shares and use the sale to facilitate the establishment of a hedge position by investors in the notes. BSC will receive all proceeds from such common stock offerings and lending transactions under this agreement. We will not receive any of the proceeds from these transactions. BSC is obligated to return the shares to us in the event of certain circumstances, including the redemption of the notes or the conversion of shares pursuant to the terms of the 3.25% convertible notes offering.

The 3,122,263 shares of common stock outstanding as of December 31, 2006, under the Share Lending Agreement are required to be returned to the Company. The shares are treated in basic and diluted earnings per share as if they were already returned and retired. There is no impact of the shares of common stock lent under the Share Lending Agreement in the earnings per share calculation.

Senior Credit Facility

In 2005, we amended our existing credit agreement and entered into an amended and restated senior credit agreement (the Senior Credit Facility) and a second lien term loan (the Term Loan) that expanded our borrowing capabilities and extended our credit facility for an additional two years. Total lender commitments under the Senior Credit Facility were $200.0 million which matures on February 25, 2010. Revolving borrowings under the Senior Credit Facility are subject to periodic redeterminations of the borrowing base, which is currently established at $150.0 million, and is scheduled to be redetermined in late March 2007, based upon our 2006 year-end reserve report. With a portion of the net proceeds of the offering of 3.25% Convertible Senior Notes in December 2006, we fully repaid and extinguished the $50.0 million Term Loan and repaid $113.5 million of the Revolving borrowings under the Senior Credit Facility. Interest on revolving borrowings under the Senior Credit Facility accrues at a rate calculated, at our option, at either the bank base rate plus 0.00% to 0.50%, or LIBOR plus 1.25% to 2.00%, depending on borrowing base utilization.

The terms of the Senior Credit Facility require us to maintain certain covenants. Capitalized terms are defined in the credit agreement. The covenants include:

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Current Ratio of 1.0/1.0;

Interest Coverage Ratio which is not less than 3.0/1.0 for the trailing four quarters, and

Total Debt no greater than 3.5 times EBITDAX (1) for the trailing four quarters.

(1) EBITDAX is defined as Earnings before interest expense, income tax, DD&A and exploration expense.

As of December 31, 2006, we were in compliance with all of the financial covenants of the credit agreement.

Series B Convertible Preferred Stock

Our Series B Convertible Preferred Stock (the Series B Convertible Preferred Stock) was initially issued on December 21, 2005, in a private placement of 1,650,000 shares for net proceeds of $79.8 million (after offering costs of $2.7 million). Each share of the Series B Convertible Preferred Stock has a liquidation preference of $50 per share, aggregating to $82.5 million, and bears a dividend of 5.375% per annum. Dividends are payable quarterly in arrears beginning March 15, 2006. If we fail to pay dividends on our Series B Convertible Preferred Stock on any six dividend payment dates, whether or not consecutive, the dividend rate per annum will be increased by 1.0% until we have paid all dividends on our Series B Convertible Preferred Stock for all dividend periods up to and including the dividend payment date on which the accumulated and unpaid dividends are paid in full.

Each share is convertible at the option of the holder into our common stock, par value $0.20 per share (the Common Stock) at any time at an initial conversion rate of 1.5946 shares of Common Stock per share, which is equivalent to an initial conversion price of approximately $31.36 per share of Common Stock. Upon conversion of the Series B Convertible Preferred Stock, we may choose to deliver the conversion value to holders in cash, shares of Common Stock, or a combination of cash and shares of Common Stock.

If a fundamental change occurs, holders may require us in specified circumstances to repurchase all or part of the Series B Convertible Preferred Stock. In addition, upon the occurrence of a fundamental change or specified corporate events, we will under certain circumstances increase the conversion rate by a number of additional shares of Common Stock. A fundamental change will be deemed to have occurred if any of the following occurs:

We consolidate or merge with or into any person or convey, transfer, sell or otherwise dispose of or lease all or substantially all of our assets to any person, or any person consolidates with or merges into us or with us, in any such event pursuant to a transaction in which our outstanding voting shares are changed into or exchanged for cash, securities, or other property, or

We are liquidated or dissolved or adopt a plan of liquidation or dissolution.

A fundamental change will not be deemed to have occurred if at least 90% of the consideration in the case of a merger or consolidation under the first clause above consists of common stock traded on a U.S. national securities exchange and the Series B Preferred Stock becomes convertible solely into such common stock.

On or after December 21, 2010, we may, at our option, cause the Series B Convertible Preferred Stock to be automatically converted into that number of shares of Common Stock that are issuable at the then-prevailing conversion rate, pursuant to the Company Conversion Option. We may exercise our conversion right only if, for 20 trading days within any period of 30 consecutive trading days ending on the trading day prior to the announcement of our exercise of the option, the closing price of the Common Stock equals or exceeds 130% of the then-prevailing conversion price of the Series B Convertible Preferred Stock. The Series B Convertible Preferred Stock is non-redeemable by us.

We used the net proceeds of the offering of Series B Convertible Preferred Stock to fully repay all outstanding indebtedness under our senior revolving credit facility. The remaining net proceeds of the offering were added to our working capital to fund 2006 capital expenditures and for other general corporate purposes.

On January 23, 2006, the initial purchasers of the Series B Convertible Preferred Stock exercised their over-allotment option to purchase an additional 600,000 shares at the same price per share, resulting in net proceeds of $29.0 million, which was used to fund our 2006 capital expenditure program.

Summary of Critical Accounting Policies

The following summarizes several of our critical accounting policies. See a complete list in Note 1 Description of Business and Significant Accounting Policies to our consolidated financial statements.

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Proved oil and natural gas reserves

Proved reserves are defined by the SEC as those volumes of crude oil, condensate, natural gas liquids and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered through existing wells with existing equipment and operating methods. Although our external engineers are knowledgeable of and follow the guidelines for reserves as established by the SEC, the estimation of reserves requires the engineers to make a significant number of assumptions based on professional judgment. Estimated reserves are often subject to future revision, certain of which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. Changes in oil and natural gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions inherently lead to adjustments of depreciation rates utilized by us. We cannot predict the types of reserve revisions that will be required in future periods.

Successful efforts accounting

We utilize the successful efforts method to account for exploration and development expenditures. Unsuccessful exploration wells, as well as other exploration expenditures such as seismic costs, are expensed and can have a significant effect on operating results. Successful exploration drilling costs, all development capital expenditures and asset retirement costs are capitalized and systematically charged to expense using the units of production method based on proved developed oil and natural gas reserves as estimated by engineers. Certain costs related to fields or areas that are not fully developed are charged to expense using the units of production method based on total proved oil and natural gas reserves.

Impairment of properties

We continually monitor our long-lived assets recorded in oil and gas properties in the Consolidated Balance Sheets to ensure that they are fairly presented. We must evaluate our properties for potential impairment when circumstances indicate that the carrying value of an asset could exceed its fair value. Performing these evaluations requires a significant amount of judgment since the results are based on estimated future events. Such events include a projection of future oil and natural gas sales prices, an estimate of the ultimate amount of recoverable proved and probable oil and natural gas reserves that will be produced from a field, the timing of this future production, future costs to produce the oil and natural gas, and future inflation levels. The need to test a property for impairment can be based on several factors, including a significant reduction in sales prices for oil and/or natural gas, unfavorable adjustments to reserves, or other changes to contracts, environmental regulations or tax laws. We cannot predict the amount of impairment charges that may be recorded in the future.

Asset retirement obligations

We are required to make estimates of the future costs of the retirement obligations of our producing oil and gas properties. This requirement necessitates us to make estimates of our property abandonment costs that, in some cases, will not be incurred until a substantial number of years in the future. Such cost estimates could be subject to significant revisions in subsequent years due to changes in regulatory requirements, technological advances and other factors which may be difficult to predict.

Income taxes

We are subject to income and other related taxes in areas in which we operate. When recording income tax expense, certain estimates are required by management due to timing and the impact of future events on when income tax expenses and benefits are recognized by us. We periodically evaluate our tax operating loss and other carryforwards to determine whether a gross deferred tax asset, as well as a related valuation allowance, should be recognized in our financial statements. As of December 31, 2006, and in certain prior years, we have reported a net deferred tax asset on our Consolidated Balance Sheet, after deduction of the related valuation allowance, which has been determined on the basis of management s estimation of the likelihood of realization of the gross deferred tax asset as a deduction against future taxable income.

Derivative Instruments

As discussed in Item 7A. Quantitative and Qualitative Disclosures About Market Risk, we periodically utilize derivative instruments to manage both our commodity price risk and interest rate risk. We consider the use of these instruments to be hedging activities. Pursuant to derivative accounting rules, we are required to use mark to market accounting to reflect the fair value of such derivative instruments on our Consolidated Balance Sheet. To the extent that we are able to demonstrate that our use of derivative instruments qualifies as hedging activities, the offsetting entry to the changes in fair value of these instruments is accounted for in Other Comprehensive Income (Loss). To the extent that such derivatives are deemed to be ineffective, the offsetting entry to the changes in fair value is reflected in earnings.

At the inception of each hedge, we document that the derivative will be highly effective in offsetting expected changes in cash flows from the item hedged. A hedge must be determined to be highly effective under accounting rules in order to qualify for hedge accounting treatment. This assessment, which is updated quarterly, includes an evaluation of the most recent historical correlation between the derivative and the item hedged. In this analysis, changes in monthly settlement prices on our oil and gas derivatives are compared with the change in physical daily indexed prices that we receive from the field purchasers for our oil and gas production designated for hedging. Should a hedge not be highly effective , it no longer qualifies for hedge accounting treatment and changes in fair value of the hedge are recognized in earnings.

Price volatility within a measured month is the primary factor affecting the analysis of effectiveness of our oil and natural gas swaps. Volatility can reduce the correlation between the hedge settlement price and the price received for physical deliveries. Secondary factors contributing to changes in pricing differentials include changes in the basis differential which is the difference in the locally indexed price received for daily physical deliveries of hedged quantities and the index price used in hedge settlement, and changes in grade and quality factors of the hedged oil and natural gas production which would further impact the price received for physical deliveries.

Not withstanding the determination that certain commodity swaps in 2005 and the fourth quarter of 2006, were not highly effective, management continues to believe that our oil and gas price hedge strategy has been effective in satisfying our financial objective of providing cash flow stability.

Our hedge agreements currently consist of (a) swaps, where we receive a fixed price and pay a floating price, based on NYMEX quoted prices; and (b) collars, where we receive the excess, if any, of the floor price over the reference price, based on NYMEX quoted prices, and pay the excess, if any, of the reference price over the ceiling price. The terms of our current hedge agreements are described in Note 8 Hedging Activities to our consolidated financial statements.

Share-Based Compensation Plans

For all new, modified and unvested share-based payment transactions with employees, we measure at fair value and recognize as compensation expense over the requisite period. The fair value of each option award is estimated using a Black-Scholes option valuation model that requires us to develop estimates for assumptions used in the model. The Black-Scholes valuation model uses the following assumptions: expected volatility, expected term of option, risk-free interest rate and dividend yield. Expected volatility estimates are developed by us based on historical volatility of our stock. We use historical data to estimate the expected term of the options. The risk-free interest rate for periods within the expected life of the option is based on the U.S. Treasury yield in effect at the grant date. Our common stock does not pay dividends; therefore the dividend yield is zero.

New Accounting Pronouncements

See Note 1 Description of Business and Significant Accounting Policies New Accounting Pronouncements to our consolidated financial statements.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements to enhance our liquidity and capital resource positions, or for any other purpose.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk.*

Commodity Price Risk

Despite the measures taken by us to attempt to control price risk, we remain subject to price fluctuations for natural gas and crude oil sold in the spot market. Prices received for natural gas sold on the spot market are volatile due primarily to seasonality of demand and other factors beyond our control. Domestic crude oil and gas prices could have a material adverse effect on our financial position, results of operations and quantities of reserves recoverable on an economic basis.

We enter into futures contracts or other hedging agreements from time to time to manage the commodity price risk for a portion of our production. We consider these agreements to be hedging activities and, as such, monthly settlements on the contracts that qualify for hedge accounting are reflected in our crude oil and natural gas sales. Our strategy, which is administered by the Hedging Committee of the Board of Directors, and reviewed periodically by the entire Board of Directors, has been to generally hedge between 30% and 70% of our production. As of December 31, 2006, the commodity hedges we utilized were in the form of: (a) swaps, where we receive a fixed price and pay a floating price, based on NYMEX quoted prices; and (b) collars, where we receive the excess, if any, of the floor price over the reference price, based on NYMEX quoted prices, and pay the excess, if any, of the reference price over the ceiling price. See Note 8 Hedging Activities to our consolidated financial statements for additional information.

Our hedging contracts fall within our targeted range of 30% to 70% of our estimated net oil and gas production volumes for the applicable periods of 2006. The fair value of the crude oil and natural gas hedging contracts in place at December 31, 2006, resulted in an asset of $13.4 million. Based on oil and gas pricing in effect at December 31, 2006, a hypothetical 10% increase in oil and gas prices would have decreased the derivative asset to $11.9 million while a hypothetical 10% decrease in oil and gas prices would have increased the derivative asset to $14.9 million.

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Interest Rate Risk

We have a variable-rate debt obligation that exposes us to the effects of changes in interest rates. To partially reduce our exposure to interest rate risk, from time to time we enter into interest rate swap agreements. At December 31, 2006, we had the following interest rate swaps in place with BNP (in millions).

Effective Date	Maturity Date	LIBOR Swap Rate	Notional Amount
02/27/06	02/26/07	4.08%	23.0
02/27/06	02/26/07	4.85%	17.0
02/27/07	02/26/09	4.86%	40.0

The fair value of the interest rate swap contracts in place at December 31, 2006, resulted in an asset of $0.2 million. Based on interest rates at December 31, 2006, a hypothetical 10% increase or decrease in interest rates would not have a material effect on the asset.

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Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Goodrich Petroleum Corporation:

We have audited the accompanying consolidated balance sheets of Goodrich Petroleum Corporation and Subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of operations, cash flows, stockholders equity and comprehensive income (loss) for each of the years in the three-year period ended December 31, 2006. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Goodrich Petroleum Corporation and Subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2006, the Company changed its method of accounting for share based payments.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Goodrich Petroleum Corporation s internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 14, 2007 expressed an unqualified opinion on management s assessment of, and the effective operation of, internal control over financial reporting.

KPMG LLP
New Orleans, Louisiana

March 14, 2007 except for the effects of discontinued operations, as discussed in Note 12, which is as of August 6, 2007

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEET
(In Thousands, Except Share Amounts)

	December 31, 2006	December 31, 2005
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 6,184	$ 19,842
Accounts receivable, trade and other, net of allowance	9,665	6,397
Accrued oil and gas revenue	10,689	11,863
Fair value of oil and gas derivatives	13,419	
Fair value of interest rate derivatives	219	107
Prepaid expenses and other	994	463
Total current assets	41,170	38,672
PROPERTY AND EQUIPMENT:		
Oil and gas properties (successful efforts method)	575,666	316,286
Furniture, fixtures and equipment	1,463	1,075
	577,129	317,361
Less: Accumulated depletion, depreciation and amortization	(156,509)	(74,229)
Net property and equipment	420,620	243,132
OTHER ASSETS:		
Restricted cash and investments	2,039	2,039
Deferred tax asset	9,705	11,580
Other	5,730	1,103
Total other assets	17,474	14,722
TOTAL ASSETS	$ 479,264	$ 296,526
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 36,263	$ 31,574
Accrued liabilities	26,811	15,973
Fair value of oil and gas derivatives		23,271
Accrued abandonment costs	263	92
Total current liabilities	63,337	70,910
LONG-TERM DEBT	201,500	30,000
Accrued abandonment costs	9,294	7,868
Fair value of oil and gas derivatives		6,159
Total liabilities	274,131	114,937

Commitments and contingencies (See Note 10)		
STOCKHOLDERS EQUITY:		
Preferred stock: 10,000,000 shares authorized:		
Series A convertible preferred stock, $1.00 par value, issued and outstanding none and 791,968 shares, respectively		792
Series B convertible preferred stock, $1.00 par value, issued and outstanding 2,250,000 and 1,650,000 shares, respectively	2,250	1,650
Common stock: $0.20 par value, 50,000,000 shares authorized; issued and outstanding 28,218,422 and 24,804,737 shares, respectively	5,049	4,961
Additional paid in capital	213,666	187,967
Accumulated deficit	(14,571)	(8,649)
Unamortized restricted stock awards		(2,066)
Accumulated other comprehensive loss	(1,261)	(3,066)
Total stockholders equity	205,133	181,589
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 479,264	$ 296,526

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(In Thousands, Except Per Share Amounts)

	Year Ended December 31,		
	2006	2005	2004
REVENUES:			
Oil and gas revenues	$ 73,933	$ 34,986	$ 3,759
Other	838	325	151
	74,771	35,311	3,910
OPERATING EXPENSES:			
Lease Operating expense	13,182	3,821	347
Production taxes	2,851	1,809	164
Transportation	3,791	558	
Depreciation, depletion and amortization	37,225	12,214	1,486
Exploration	5,888	5,697	955
Impairment of oil and gas properties	9,886	340	
General and administrative	17,223	8,622	5,821
Gain on sale of assets	(23)	(235)	(50)
	90,023	32,826	8,723
Operating income (loss)	(15,252)	2,485	(4,813)
OTHER INCOME AND (EXPENSE)			
Interest expense	(7,845)	(2,359)	(1,110)
Gain (loss) on derivatives not qualifying for hedge accounting	38,128	(37,680)	2,317
Loss on early extinguishment of debt	(612)		
	29,671	(40,039)	1,207
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	14,419	(37,554)	(3,606)
INCOME TAX (EXPENSE) BENEFIT	(5,120)	13,144	8,594
INCOME (LOSS) FROM CONTINUING OPERATIONS	9,299	(24,410)	4,988
Discontinued operations including gain on sale of assets, net of tax	(7,660)	6,960	13,539
NET INCOME (LOSS)	1,639	(17,450)	18,527
PREFERRED STOCK DIVIDENDS	6,016	755	633
PREFERRED STOCK REDEMPTION PREMIUM	1,545		
NET INCOME (LOSS) APPLICABLE TO COMMON STOCK	$ (5,922)	$ (18,205)	$ 17,894

NET INCOME (LOSS) PER COMMON SHARE-BASIC			
INCOME (LOSS) FROM CONTINUING OPERATIONS	$ 0.37	$ (1.05)	$ 0.26
DISCONTINUED OPERATIONS	$ (0.30)	$ 0.30	$ 0.69
NET INCOME (LOSS)	$ 0.07	$ (0.75)	$ 0.95
NET INCOME (LOSS) APPLICABLE TO COMMON STOCK	$ (0.24)	$ (0.78)	$ 0.92
NET INCOME (LOSS) PER COMMON SHARE-DILUTED			
INCOME (LOSS) FROM CONTINUING OPERATIONS	$ 0.37	$ (1.05)	$ 0.25
DISCONTINUED OPERATIONS	$ (0.31)	$ 0.30	$ 0.66
NET INCOME (LOSS)	$ 0.06	$ (0.75)	$ 0.91
NET INCOME (LOSS) APPLICABLE TO COMMON STOCK	$ (0.24)	$ (0.78)	$ 0.88
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING-BASIC	24,948	23,333	19,552
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING-DILUTED	25,412	23,333	20,347

See accompanying notes to consolidated financial statements

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In Thousands)

	Year Ended December 31,		
	2006	2005	2004
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income (loss)	$ 1,639	$ (17,450)	$ 18,527
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depletion, depreciation, and amortization	52,642	25,563	11,717
Unrealized (gain) loss on derivatives not qualifying for hedge accounting	(40,185)	26,960	(2,317)
Deferred income taxes	904	(9,396)	(1,303)
Dry hole costs	7,926	2,014	
Amortization of leasehold costs	5,488	3,344	1,035
Impairment of oil and gas properties	24,790	340	
Stock based compensation (non-cash)	5,962	1,383	1,031
Loss on early extinguishment of debt	612		
Gain on sale of assets	(23)	(235)	(814)
Other non-cash items	476	(156)	(967)
Change in assets and liabilities:			
Accounts receivable, trade and other, net of allowance	(3,268)	786	(3,683)
Accrued oil and gas revenue	1,174	(8,741)	(293)
Prepaid expenses and other	(531)	169	(280)
Accounts payable	4,689	8,222	16,644
Accrued liabilities	2,838	12,759	1,731
Net cash provided by operating activities	65,133	45,562	41,028
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(261,435)	(164,551)	(47,501)
Proceeds from sale of assets	2,698	980	2,087
Net cash used in investing activities	(258,737)	(163,571)	(45,414)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Principal payments of bank borrowings	(184,500)	(118,500)	(1,000)
Proceeds from bank borrowings	181,000	121,500	8,000
Proceeds from convertible note offering	175,000		
Net proceeds from common stock offering		53,112	
Net proceeds from preferred stock offering	28,973	79,775	
Redemption of preferred stock	(9,319)		
Exercise of stock options and warrants	406	477	340
Production payments		(297)	(361)
Deferred financing costs	(5,598)	(971)	
Preferred stock dividends	(6,016)	(634)	(633)
Other			