DUNCAN GEORGE L
Form 4
March 22, 2012

FORM 4

Check this box if no longer subject to Section 16. Form 4 or Form 5 obligations may continue. *See* Instruction 1(b).

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

STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

OMB APPROVAL
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(Print or Type Responses)

1. Name and Address of Reporting Person *
DUNCAN GEORGE L
(Last) (First) (Middle)
C/O ENTERPRISE BANCORP, 222 MERRIMACK STREET
(Street)
LOWELL, MA 01852
(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
ENTERPRISE BANCORP INC /MA/ [EBTC]

3. Date of Earliest Transaction (Month/Day/Year)
03/20/2012

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer
(Check all applicable)
__X__ Director _____ 10% Owner
__X__ Officer (give title below) _____ Other (specify below)
Chairman

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			
Common Stock	03/20/2012		A		9,400	A	$ 0	375,774	D	
Common Stock								49,863	I	By wife

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

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SEC 1474 (9-02)

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security (Instr. 3)	2. Conversion or Exercise Price of Derivative Security	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any (Month/Day/Year)	4. Transaction Code (Instr. 8)		5. Number of Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)		6. Date Exercisable and Expiration Date (Month/Day/Year)		7. Title and Amount of Underlying Securities (Instr. 3 and 4)		8. P Der Sec (Ins
				Code	V	(A)	(D)	Date Exercisable	Expiration Date	Title	Amount or Number of Shares	
Stock option (Right to buy)	$ 16.25	03/20/2012		A		9,000		(1)	03/19/2019	Common Stock	9,000	

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
DUNCAN GEORGE L C/O ENTERPRISE BANCORP 222 MERRIMACK STREET LOWELL, MA 01852	X		Chairman	

Signatures

/s/ John P. Clancy, Jr. as attorney-in-fact for George L. Duncan	03/22/2012
**Signature of Reporting Person	Date

Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

(1) Option vests 25% per year on the anniversary of the grant date with the first installment vesting on 3/20/13

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
Potential persons who are to respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB number. OLOR="#cceeff">

Income from continuing operations before income taxes

26,816 195,446 261,014

Provision for income taxes

1,139 (132)

Income from continuing operations

26,816 194,307 261,146

Discontinued operations

1,680

Loss on sale of discontinued operations

(632)

Net income

$27,864 $194,307 $261,146

Sales volumes:

Oil (MBbl)(2)

3,688 5,708 7,459

Natural gas (MMcf)

8,794 9,006 9,225

Oil equivalents (MBoe)

5,154 7,209 8,997

Average prices(2):

Oil, without hedges ($/Bbl)

$38.85 $52.45 $55.30

Oil, with hedges ($/Bbl)

37.12 52.45 55.30

Natural gas ($/Mcf)

5.06 6.93 6.08

Oil equivalents, without hedges ($/Boe)

36.45 50.19 52.09

Oil equivalents, with hedges ($/Boe)

35.20 50.19 52.09

(1) Revenues for 2004 include $226,664,000 for crude oil marketing and trading, and operating expenses include $227,210,000 for crude oil marketing and trading.

(2) Oil sales volumes are 21 MBbls less than oil production volumes for the year ended 2006. Average prices have been calculated using sales volumes.

Year Ended December 31, 2006 Compared to the Year Ended December 31, 2005

Revenues.

Oil and natural gas sales. Oil and natural gas sales for the year ended December 31, 2006 were $468.6 million, a 30% increase over sales of $361.8 million for the comparable period of 2005. Increased sales resulted from additional sales volumes, which increased 25%, and an increase of $1.90 in our realized price per Boe from $50.19 to $52.09. During 2006, we experienced an increase in the differential between NYMEX prices and our realized crude oil prices. The differential per barrel for the twelve months ended December 31, 2006 was $11.04 as compared to $5.24 for the comparable period of 2005. We realized a crude oil differential in December 2006 of $13.32 per Bbl compared to a high of $14.25 per Bbl in March 2006. Among the factors contributing to the higher differentials were higher Canadian oil imports, increases in production in the Rocky Mountain region, refinery downtime in the Rocky Mountain region, downstream transportation capacity constraints, and reduced seasonal demand for gasoline. We are unable to predict when, or if, the differential will revert back to pre-2006 levels.

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The following tables reflect our production by product and region for the periods presented.

	Year ended December 31,				
	2005		2006		
	Volume	Percent	Volume	Percent	Percent increase
Oil (MBbl)(1)	5,708	79%	7,480	83%	31%
Natural Gas (MMcf)	9,006	21%	9,225	17%	2%
Total (MBoe)	7,209	100%	9,018	100%	25%

	Year ended December 31,				
	2005		2006		
	MBoe	Percent	MBoe	Percent	Percent increase (decrease)
Rocky Mountain	5,410	75%	7,159	79%	32%
Mid-Continent	1,361	19%	1,497	17%	10%
Gulf Coast	438	6%	362	4%	(17)%
Total MBoe	7,209	100%	9,018	100%	25%

(1) Oil sales volumes are 21 MBbls less than oil production volumes for the year ended December 31, 2006.

Oil production volumes increased 31% during the year ended December 31, 2006 in comparison to the year ended December 31, 2005. Production increases in the Bakken field contributed incremental volumes in excess of 2005 levels of 815 MBbls, and the Red River units contributed 865 MBbls of incremental production. Initial production commenced in the Bakken field in August 2003 and has increased thereafter, as we have continued exploration and development activities within the field. Favorable results from the enhanced recovery program and additional field development have been the primary contributors to production growth in the Red River units.

Oil and Natural Gas Service Operations. Our oil and natural gas service operations consist primarily of sales of high-pressure air and the treatment and sale of lower quality crude oil, or reclaimed oil. We initiated the sale of high-pressure air from our Red River units to a third party in 2004 and recorded revenues of $3.1 million during 2006 and $3.0 million during 2005. Higher prices for reclaimed oil sold from our central treating unit in 2006 increased oil and natural gas service operations revenues by $0.8 million to $9.4 million at year end 2006. Associated oil and natural gas service operations expenses increased $0.2 million to $8.2 million during the year ended December 31, 2006 from $8.0 million during 2005 due mainly to an increase in the costs of purchasing and treating oil for resale.

Operating Costs and Expenses

Production Expense and Tax. Production expense increased $10.1 million or 19% during the year ended December 31, 2006 to $62.9 million from $52.8 million during the year ended December 31, 2005. The increase in 2006 was due to increases of $3.8 million in workovers, $1.4 million in energy and chemical costs, $1.5 million in repairs, $1.1 million in overhead, $0.6 million in outside operated well costs, $0.5 million in saltwater disposal expenses, $0.4 million in contract labor costs, and as a result of new wells drilled.

Production taxes increased $6.3 million during the year ended December 31, 2006 to $22.3 million from $16.0 million during 2005. The majority of the production tax increase was $5.9 million in the Rocky Mountain region. Production tax as a percentage of oil and natural gas sales was 4.4% for the year ended December 31, 2005 compared to 4.8% for the year ended December 31, 2006. Production taxes are based on the wellhead values of production and vary by state. Additionally, some states offer exemptions or reduced production tax rates for wells that produce less than a certain quantity of oil or gas and to encourage certain activities, such as horizontal drilling and enhanced recovery projects. In Montana, new horizontal wells qualify for a tax incentive and are taxed at 0.76% during the first 18 months of production. After the 18 month incentive period expires, the

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tax rate increases to 9.26%. In 2006, 33 new producing wells were added in Montana at a tax rate of 0.76% and 21 wells reached the end of their exemption period and their tax rate was increased to 9.26%. Also in the Rocky Mountain region, 8 wells were added in North Dakota at a rate of 11.5%. As production tax incentives we currently receive for horizontal wells in Montana continue to reach the end of the 18 month incentive period, our overall rate is expected to increase.

On a unit of sales basis, production expense and production taxes were as follows:

	Year ended December 31,		Percent increase (decrease)
	2005	2006	
Production expense ($/Boe)	$ 7.32	$ 6.99	(5)%
Production tax ($/Boe)	2.22	2.48	12%
Production expense and tax ($/Boe)	$ 9.54	$ 9.47	(1)%

Exploration Expense. Exploration expenses consist primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. Exploration expenses increased $14.5 million in 2006 to $19.7 million due primarily to an increase in dry hole expense of $11.9 million and an increase in seismic expenses of $2.0 million. The Rocky Mountain region contributed 54% of the dry hole costs, 24% was in the Mid-Continent region and the remaining 22% was in the Gulf Coast region. The increase in dry hole expense was due to a higher level of drilling during 2006. Exploration capital expenditures were $68.7 million in 2006 compared to $9.3 million in 2005.

Depreciation, Depletion, Amortization and Accretion (DD&A.) DD&A on oil and gas properties increased $15.3 million in 2006 due to increased production and additional properties being added through our drilling program. The DD&A rate on oil and gas properties for 2005 was $6.50 per Boe compared to $6.91 per Boe for 2006. Accretion expense increased $0.1 million to $1.7 million during 2006 from $1.6 million during 2005.

Property Impairments. Property impairments increased during 2006 by $4.9 million to $11.8 million compared to $6.9 million for 2005. Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Individually significant non-producing properties are periodically assessed for impairment of value and a loss is recognized at the time of impairment by providing an impairment allowance. Other non-producing properties are amortized on a composite method based on our estimated experience of successful drilling and the average holding period. Impairment of non-producing properties increased $1.0 million during 2006 to $5.4 million compared to $4.4 million for 2005.

Impairment provisions for developed oil and gas properties were approximately $2.5 million for the year ended December 31, 2005 and $6.3 million for the year ended December 31, 2006. The increase in 2006 impairment expense resulted primarily from developmental well dry holes and properties where the associated field level reserves were not sufficient to recover capitalized drilling and completion costs.

General and Administrative Expense. General and administrative expense decreased primarily due to a $10.8 million decrease in equity compensation expense net of a charge of $1.5 million associated with our President s non-equity compensation plan as described under Management Summary Compensation Table, associated with restricted stock grants and stock options under our long-term incentive plans. The decrease in equity compensation was attributable to lower per share value for our equity as a result of a decline in our PV-10 value due to lower oil and gas prices in the last half of 2006. On a volumetric basis, general and administrative expense was $2.56 per Boe for 2006 compared to $4.34 per Boe for 2005. We have granted stock options and restricted stock to our employees. The terms of the grants require that, while we are a private company, we are required to purchase vested options and restricted stock at each employee s request at a per share amount derived from our shareholders equity value adjusted quarterly for our PV-10. The obligation to purchase the options is eliminated in the event we become a reporting company under Section 12 of the Exchange Act.

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Gain on Sale of Assets. During 2005, we realized a gain of $6.1 million on the sale of oil and gas wells and a loss of $3.1 million on the termination of compressor capital leases. Gains in 2006 amounted to approximately $0.3 million on miscellaneous asset sales.

Interest Expense. Interest expense decreased 20% for 2006 due to a lower average outstanding debt balance on our credit facility of $156.6 million compared to $184.0 million for 2005 even though the weighted average interest rate on our credit facility was 6.36% for the year ended December 31, 2006 compared to 5.10% for the year ended December 31, 2005. Additionally, in 2005, we had an outstanding balance due to our principal shareholder for $48.0 million which was paid in full during December 2005. We paid $2.9 million in interest on this note during 2005 at a rate of 6%.

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

Revenues

Oil and Natural Gas Sales. Oil and natural gas sales increased $180.4 million or 99% to $361.8 million in 2005. The increase was attributable to higher production volumes and higher oil and natural gas prices. During 2004, our average wellhead oil price was $38.85 per Bbl and our wellhead natural gas price was $5.06 per Mcf, compared to $52.45 per Bbl for oil and $6.93 per Mcf for natural gas during 2005. The increases in our wellhead prices were due to general industry price escalations in our producing regions. Our oil sales in 2004 were reduced by a $6.4 million loss in our hedging activities. We did not hedge our production during 2005. The following tables reflect our production by product and region for the periods presented:

	Year ended December 31,				
	2004		2005		
	Volume	Percent	Volume	Percent	Percent increase
Oil (MBbl)	3,688	72%	5,708	79%	55%
Natural Gas (MMcf)	8,794	28%	9,006	21%	2%
Total (MBoe)	5,154	100%	7,209	100%	40%

	Year ended December 31,				
	2004		2005		
	MBoe	Percent	MBoe	Percent	Percent increase (decrease)
Rocky Mountain	3,279	64%	5,410	75%	65%
Mid-Continent	1,461	28%	1,361	19%	(7)%
Gulf Coast	414	8%	438	6%	6%

Total MBoe	5,154	100%	7,209	100%	40%

Production increases in our Bakken field and Red River units in the Rocky Mountain region of 1,226 MBoe and 1,051 MBoe, respectively, accounted for the growth in production for 2005. We commenced drilling our initial well in the Bakken field in May 2003 and completed it as a producing well in August 2003. Our well count in the Bakken field rose from 25 gross (14.5 net) wells at December 31, 2004 to 60 gross (34.2 net) wells at December 31, 2005. Favorable response to the enhanced recovery program was the primary factor in the production growth in the Red River units.

Crude Oil Marketing and Trading. During 2004 and the first three months of 2005, we purchased barrels back from certain of our wellhead purchasers downstream of the initial sales point to exchange at the Cushing, Oklahoma hub in order to minimize pricing differentials with the NYMEX oil futures contract. In 2005, revenues of $39.8 million and expenses of $39.7 million pertaining to these marketing activities were netted as provided by Emerging Issues Task Force (EITF) 04-13, which we adopted as of January 1, 2005. We presented these purchase and sale activities gross in the 2004 income statement as crude oil marketing and trading revenues of

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$226.7 million and crude oil marketing and trading expenses of $227.2 million under the guidance provided by EITF 99-19, Reporting Revenues Gross as a Principal and/or Net as an Agent. We ceased marketing our production in this manner in March 2005 and now generally market our production at the wellhead.

Oil and Natural Gas Service Operations. Our oil and natural gas service operations consist primarily of sales of high-pressure air and the treatment and sale of lower quality crude oil (reclaimed oil). We initiated the sale of high-pressure air from our Red River units to a third party in 2004, and recorded revenues of $2.0 million and $3.0 million during 2004 and 2005, respectively. Higher prices for reclaimed oil sold from our central treating unit in 2005 increased oil and natural gas service operations revenues by $2.2 million to $8.8 million. Associated oil and natural gas service operations expenses increased $2.0 million from 2004 compared to 2005 due principally to an increase in the costs of purchasing and treating oil for resale.

Operating Costs and Expenses

Production Expense and Tax. Our production expense increased $9.0 million or 21%. This increase was primarily due to production expense associated with the 80 gross (45.4 net) productive wells drilled during 2005, industry inflation and higher energy costs in the Red River units. On a unit of production basis, production expense fell from $8.49 per Boe in 2004 to $7.32 per Boe in 2005.

Energy costs in the Red River units increased $3.0 million to $9.9 million in 2005. The increased energy costs were mainly due to higher electrical costs, resulting from higher production volumes, to run compressors for the high-pressure air injection and other enhanced recovery operations in the field. Workovers in this field also increased from $0.2 million in 2004 to $1.8 million in 2005.

Production tax increased $3.7 million or 30% in 2005 compared to the 99% increase in oil and gas sales. As a percentage of oil and natural gas revenues, production tax was 4.4% in 2005 compared to 6.8% in 2004. In the state of Montana, a horizontal well qualifies for a 0.76% production tax rate on oil and natural gas sales for the first 18 months of production. Thereafter, the production tax rate is 9.26%. All of the wells we drilled in the Montana Bakken field qualified for the reduced production tax rate.

Our oil and natural gas revenues from the Montana Bakken field increased to approximately $93.3 million in 2005 from $19.1 million in the prior year. The addition of approximately $74.2 million in oil and gas revenues at a 0.76% production tax rate was the principal reason production tax increased 30% compared to the 99% increase in oil and gas sales.

On a unit of sales basis, production expense and production tax were as follows:

	Year ended December 31,		
	2004	**2005**	**Percent decrease**

Production expense ($/Boe)	$ 8.49	$ 7.32	(14)%
Production tax ($/Boe)	2.39	2.22	(7)%
Production expense and tax ($/Boe)	$ 10.88	$ 9.54	(12)%

Exploration Expense. Exploration expense decreased from 2004 to 2005 as a result of a reduction primarily in our dry hole expense from $9.5 million in 2004 to $1.4 million in 2005. The higher dry hole expense during 2004 was primarily attributable to dry holes in the Gulf Coast region with a higher per well cost.

Depreciation, Depletion, Amortization and Accretion (DD&A). The DD&A rate per Boe decreased from $7.02 per Boe in 2004 to $6.50 per Boe in 2005. The reduction in the DD&A rate per Boe was mainly due to the addition of 32,427 MBoe of proved reserves during 2005. The amount of DD&A attributable to oil and gas properties increased by $10.6 million in 2005 due to increased production volumes. Accretion expense associated with our asset retirement obligations was $1.0 million and $1.6 million in 2004 and 2005, respectively.

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Property Impairments. We evaluate our properties on a field-by-field basis, as may be necessary, when facts and circumstances such as downward reserve revisions or lower oil and natural gas prices indicate that their carrying amounts may not be recoverable. We recorded a $6.2 million impairment in 2004 compared to a $2.5 million impairment in 2005 on producing properties. The decrease from 2004 to 2005 was due to higher impairment charges on Gulf Coast region properties during 2004. We also evaluate our undeveloped leasehold cost and adjust the acreage valuation quarterly based on our assessment of the potential for the acreage to be developed and the market value of the acreage. Undeveloped leasehold cost is expensed over the life of the lease or transferred to the associated producing properties. Individually significant non-producing properties are periodically assessed for impairment of value and a loss is recognized if necessary. During 2004 we impaired $5.5 million of undeveloped leasehold cost compared to $4.4 million during 2005.

General and Administrative Expense. The majority of the increase in general and administrative expense for 2005 was the result of higher wages and bonuses paid to our employees. The number of employees increased from 275 at year-end 2004 to 286 at year-end 2005, which, combined with salary adjustments and cash bonus increases, increased payroll and other employee-related expenses by $5.3 million during 2005. On a volumetric basis, our general and administrative expense, including equity compensation of $2.0 million and $13.7 million, respectively, was $2.41 per Boe and $4.34 per Boe for the years ended December 31, 2004 and 2005, respectively.

Equity compensation expense increased from $2.0 million in 2004 to $13.7 million in 2005 primarily due to additional equity grants and a higher per share valuation resulting from the increase in our PV-10.

Interest Expense. Interest expense declined from $23.6 million in 2004 to $14.2 million in 2005. The decline in interest expense was attributable to a lower average bank indebtedness during 2005. At December 31, 2004, we had $230.0 million outstanding on our bank credit facility with an effective interest rate of 4.36% compared to $143.0 million outstanding at December 31, 2005, with an effective interest rate of 6.08%. We incurred $6.8 million and $9.3 million in interest on our credit facility in 2004 and 2005, respectively. On November 22, 2004, we signed a note with our principal shareholder for $50.0 million due March 31, 2008. The annual rate of interest was 6.00% and interest payments were due on the last day of each calendar quarter beginning December 31, 2004. We paid $308,000 and $2.9 million in interest in 2004 and 2005, respectively on this note to our principal shareholder. In December 2005, we paid the note in full to our principal shareholder. During November 2004, we utilized available borrowing capacity under our credit facility to redeem $119.5 million of our outstanding Senior Subordinated 10.25% Notes and paid a premium of $4.1 million due on the early redemption of the Notes. Total interest expense on the Senior Subordinated Notes during 2004 was $11.4 million.

Provision for Income Taxes. We recognized income tax expense of $1.1 million during the three months ended March 31, 2005 in connection with the sale of assets acquired prior to our conversion to a subchapter S-corporation from a subchapter C-corporation on May 31, 1997. These assets had Built in gains, as defined by Section 1374 of the Internal Revenue Code, which resulted in a taxable event for us.

Discontinued Operations. In July 2004, we completed the sale of all of the outstanding stock in Continental Gas Inc. (CGI) to our shareholders for $22.6 million in cash. The sales price was representative of the fair value of the net assets based on an appraisal by an independent third party who also provided us with an opinion of the fairness from a financial point of view, of the sale of CGI to the shareholders. The CGI assets included seven natural gas gathering systems and three natural gas-processing plants. These assets represented our entire natural gas gathering, marketing and processing segment and have been classified as discontinued operations for all periods presented.

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Liquidity and Capital Resources

Our primary sources of liquidity have been cash flows generated from operating activities and financing provided by our bank credit facility and principal shareholder. In November 2004, we signed a note with our principal shareholder for $50 million due March 31, 2008. In January 2005, our principal shareholder contributed $2.0 million of the previously loaned amount to us. We paid the $48.0 million outstanding balance due on the note in December 2005. We believe that funds from operating cash flows and the bank credit facility should be sufficient to meet our cash requirements inclusive of, but not limited to, normal operating needs, debt service obligations, planned capital expenditures, and commitments and contingencies for the next 12 months. We intend to fund our longer term cash requirements beyond 12 months through operating cash flows, commercial bank borrowings and access to equity and debt capital markets. Although our longer term needs may be impacted by factors discussed in the section entitled Risk Factors, such as declines in oil and natural gas prices, drilling results, ability to obtain needed capital on satisfactory terms, and other risks which could negatively impact production and our results of operations, we currently anticipate that we will be able to generate or obtain funds sufficient to meet our long-term cash requirements. During 2006, we declared cash dividends totaling $87.6 million to existing shareholders and, subject to forfeiture, to holders of unvested restricted stock. Of this amount, $298,000 was charged to compensation expense related to the restricted stock liability. During 2006, we paid cash dividends of $87.4 million. The unpaid balance of $218,000 relates to dividends associated with unvested restricted stock and will be paid as the restricted stock vests. On January 10, 2007, we declared a cash dividend of approximately $18.8 million to our shareholders for tax purposes and, subject to forfeiture, to holders of unvested restricted stock. On January 31, 2007, we paid $18.7 million of the dividend declared. On March 6, 2007, we declared a cash dividend of approximately $33.3 million payable in April 2007 to our shareholders of record as of March 15, 2007, for tax purposes and, subject to forfeiture, to holders of unvested restricted stock. In connection with the completion of this offering, we will convert from a subchapter S-corporation to a subchapter C-corporation, and we do not anticipate paying any additional cash dividends on our common stock in the foreseeable future. At December 31, 2005 and 2006, we had cash and cash equivalents of $6.0 million and $7.0 million, respectively, and available borrowing capacity on our credit facility of $107.0 million and $160.0 million, respectively.

Cash Flow from Operating Activities

Our net cash provided by operating activities was $93.9 million, $265.3 million and $417.0 million for the years ended December 31, 2004, 2005 and 2006, respectively. The increases in operating cash flows in 2005 and 2006 were principally due to increased production and higher oil and natural gas prices. Additionally, hedging losses were $6.4 million in 2004. There were no hedges in place during 2005 and 2006.

Cash Flow from Investing Activities

During the years ended December 31, 2004, 2005 and 2006 we invested $94.3 million, $144.8 million and $326.6 million, respectively, in our capital program, inclusive of dry hole and seismic costs. The increases in our capital program in 2005 and 2006 were due to the implementation of enhanced recovery and increased density drilling in our Red River units and additional exploration and development drilling.

Cash Flow from Financing Activities

Net cash used in financing activities was $7.2 million for 2004, $141.5 million for 2005 and $91.5 million for 2006. In 2004, cash used in financing activities was primarily attributable to the repurchase of our Senior Subordinated Notes. In 2005, cash used in financing activities was primarily attributable to the repayment of long-term debt. During 2006, cash used in financing activities was primarily attributable to the payment of cash

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dividends. Our long-term debt, including the current portion and capital leases, was $290.5 million, $143.0 million and $140.0 million at December 31, 2004, 2005 and 2006, respectively.

Credit Facility

We had $143.0 million and $140.0 million outstanding under our bank credit facility at December 31, 2005 and 2006, respectively. During 2006, capital expenditures of $326.6 million and dividends of $87.4 million were funded principally by $417.0 million in cash provided by operating activities, which benefited from an increase of $77.4 million in our accounts payable trade for the year ended December 31, 2006. As of April 12, 2007, the amount outstanding under our credit facility has increased by $129.5 million to $269.5 million. The increase is largely due to borrowings to fund cash dividends of approximately $52.0 million paid in 2007 and borrowings for the reduction in our accounts payable trade balance which had increased by $50.4 million in the fourth quarter due to the increase in our fourth quarter capital expenditures. Our fourth quarter 2006 capital expenditures were approximately $105.3 million. After giving effect to this offering at an assumed public offering price of $17.00 per share and the application of the net proceeds we will receive in this offering, we expect to have borrowings of approximately $129.9 million outstanding under our credit facility.

The credit facility matures on April 12, 2011, and borrowings under our credit facility bear interest, payable quarterly, at (a) a rate per annum equal to the London Interbank Offered Rate for one, two, three or six months as offered by the lead bank plus an applicable margin ranging from 100 to 175 basis points, depending on the percentage of our borrowing base utilized or (b) the lead bank s reference rate. The credit facility has a note amount of $750.0 million, a borrowing base of $600.0 million, subject to semi-annual redetermination, and a commitment level of $300.0 million. Our next semi-annual redetermination is during October 2007. The terms of the credit facility allow us to determine the commitment level at any level up to the borrowing base.

The credit facility contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, change material contracts, incur liens and engage in certain other transactions without the prior consent of the lenders. The facility also requires us to maintain certain ratios as defined and further described in our credit facility: a Current Ratio of not less than 1.0 to 1.0 (adjusted for available borrowing capacity), a Total Funded Debt to EBITDAX, as defined, of no greater than 3.75 to 1.0. As of December 31, 2006, we were in compliance with all covenants.

Capital Expenditures and Commitments

We evaluate opportunities to purchase or sell oil and natural gas properties in the marketplace and could participate as a buyer or seller of properties at various times. We seek acquisitions that utilize our technical expertise or offer opportunities to expand our existing core areas.

We invested approximately $326.6 million for capital and exploration expenditures in 2006 as follows (in millions):

	Amount

Exploration and development drilling	$ 248.6
Purchase of properties	6.6
Dry holes	13.3
Capital facilities, workovers and recompletions	21.1
Land costs	26.1
Seismic	3.9
Vehicles, computers and other equipment	7.0
	$ 326.6

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Expenditures for exploration and development of oil and natural gas properties are the primary use of our capital resources. We anticipate investing approximately $437.0 million for capital and exploration expenditures in 2007 as follows (in millions):

	Amount
Exploration and development drilling	$ 363
Capital facilities, workovers and recompletions	31
Land costs	32
Seismic	7
Vehicles, computers & other equipment	4
	$ 437

Our budgeted capital expenditures are expected to increase approximately 34% over the $326.6 million invested during 2006. We plan to invest approximately $209 million in development drilling. In the Red River units, we plan to invest approximately $154 million to drill infill wells and extend horizontal laterals on existing wells to increase production and sweep efficiency of the enhanced recovery projects. Most of the remaining development drilling budget is expected to be invested in the drilling of development wells in the Montana Bakken field. We have budgeted approximately $173 million for exploratory drilling with approximately $71 million and $82 million allocated to drilling exploratory wells in the North Dakota Bakken field and the Woodford Shale project, respectively.

Although we cannot provide any assurance, assuming successful implementation of our strategy, including the future development of our proved reserves and realization of our cash flows as anticipated, we believe that our remaining cash balance, cash flows from operations and borrowings available under our credit facility will be sufficient to satisfy our 2007 capital budget. The actual amount and timing of our capital expenditures may differ materially from our estimates as a result of, among other things, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments.

Shareholder Distribution

In 2004, we made a distribution of $14.9 million to our shareholders and in 2005 we made a $2.0 million distribution to our shareholders. During 2006, we declared cash dividends totaling $87.6 million to existing shareholders and, subject to forfeiture, to holders of unvested restricted stock. Of this amount, $298,000 was charged to compensation expense related to the restricted stock liability. During 2006, we paid cash dividends of $87.4 million. The unpaid balance of $218,000 relates to dividends associated with unvested restricted stock and will be paid as the restricted stock vests. On January 10, 2007, we declared a cash dividend of approximately $18.8 million to our shareholders and, subject to forfeiture, to holders of unvested restricted stock. On January 31, 2007, we paid $18.7 million of the dividend declared, of which $16.9 million was paid to our principal shareholder. On March 6, 2007, we declared a cash dividend of approximately $33.3 million to our shareholders of record and, subject to forfeiture, to holders of unvested restricted stock. On April 12, 2007, we paid $33.1 million of the dividend declared, of which $30.0 was paid to our principal shareholder. In connection with the completion of this offering, we will convert from a subchapter S-corporation to a subchapter C-corporation, and we do not anticipate paying any additional cash dividends on our common stock in the foreseeable future. See Recent Events.

Expenses to be Recognized Following Completion of the Offering

We expect to recognize a charge to earnings (estimated to be approximately $178.8 million if the conversion had occurred on December 31, 2006) to record deferred taxes as a result of our conversion to a C-corporation upon completion of this offering. This charge represents taxes provided on the difference between the book and tax basis of our assets. In addition, we expect to recognize a non-cash charge to earnings (estimated to be approximately $17.4 million as of December 31, 2006) for compensation expense associated with our equity

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compensation plans upon completion of this offering, assuming an offering price at the midpoint of the range set forth on the cover page of the prospectus.

The terms of our restricted stock grants and stock option grants under our equity compensation plans stipulate that while we are a private company, we are required to purchase the vested restricted stock and stock acquired upon stock option exercises at the request of participants in our equity compensation plans based upon the purchase price as determined by a formula specified in each award agreement. Additionally, we have the right to purchase vested shares of restricted stock and shares issued upon stock option exercises from plan participants at the same price upon termination of the participant s employment with us for any reason for a period of two years after the termination date. We have historically measured compensation cost for the awards based upon the formula purchase price which is determined by calculating a per share value for shareholders equity adjusted for the excess of each period s ending PV-10 oil and gas reserve valuation over the book value of oil and gas properties.

The right and requirement to purchase vested shares of our restricted stock and shares issued upon the exercise of stock options will lapse when we become a reporting company under Section 12 of the Exchange Act. Upon becoming a reporting company under Section 12 of the Exchange Act, we will record the charge to earnings described above to adjust the plan determined share price to the price received in this offering and account for the grants under the fair value provisions of SFAS 123(R) thereafter.

Hedging

We account for derivative instruments in accordance with SFAS No. 133 Accounting for Derivative Instruments and Hedging Activities. The specific accounting treatment for changes in the market value of the derivative instruments used in hedging activities is determined based on the designation of the derivative instruments as a cash flow or fair value hedge and effectiveness of the derivative instruments.

In 2004, we utilized fixed-price contracts and zero-cost collars to reduce exposure to unfavorable changes in oil and natural gas prices that are subject to significant and often volatile fluctuation. Under the fixed price physical delivery contracts we received the fixed price stated in the contract. Under the zero-cost collars, if the market price of crude oil was less than the ceiling strike price and greater than the floor strike price, we received market price. If the market price of crude oil exceeded the ceiling strike price or fell below the floor strike price, we received the applicable collar strike price. We recognized hedging losses of $6.4 million during 2004.

We did not hedge any of our oil or natural gas production during 2005 and 2006 and have not entered into any such hedges from January 1, 2007 through the date of this filing. We do not currently have plans to hedge any of our 2007 production.

Obligations and Commitments

We have the following contractual obligations and commitments as of December 31, 2006:

	Payments due by period				
	Total	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years
			(in thousands)		
Bank credit facility(1)	$ 140,000	$	$	$ 140,000	$
Operating lease obligations(2)	11,067	5,296	5,754	17	
Asset retirement obligations(3)	41,273	2,528	7,377	1,232	30,136
Total contractual cash obligations	$ 192,340	$ 7,824	$ 13,131	$ 141,249	$ 30,136

(1) Payments on the bank credit facility listed in the table exclude interest.

(2) Operating leases consist of compressors utilized in field operations, vehicles and office equipment.

(3) Amounts represent expected asset retirements by period.

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Critical Accounting Policies and Practices

Our historical consolidated financial statements and notes to our historical consolidated financial statements contain information that is pertinent to our management s discussion and analysis of financial condition and results of operations. Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires that our management make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. However, the accounting principles used by us generally do not change our reported cash flows or liquidity. Interpretation of the existing rules must be done and judgments made on how the specifics of a given rule apply to us.

In management s opinion, the more significant reporting areas impacted by management s judgments and estimates are revenue recognition, the choice of accounting method for oil and natural gas activities, oil and natural gas reserve estimation, asset retirement obligations and impairment of assets. Management s judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists and historical experience in similar matters. Actual results could differ from the estimates, as additional information becomes known.

Revenue Recognition

We derive substantially all of our revenues from the sale of oil and natural gas. Oil and gas revenues are recorded in the month the product is delivered to the purchaser and title transfers. We generally receive payment from one to three months after the sale has occurred. Each month we estimate the volumes sold and the price at which they were sold to record revenue. Variances between estimated revenue and actual amounts are recorded in the month payment is received.

Successful Efforts Method of Accounting

We utilize the successful efforts method of accounting for our oil and natural gas exploration and development activities. Exploration expenses, including geological and geophysical costs, rentals and exploratory dry holes, are charged against income as incurred. Costs of successful wells and related production equipment and developmental dry holes are capitalized and amortized on an individual property, field or unit basis using the unit-of-production method as oil and natural gas is produced. This accounting method may yield significantly different results than the full cost method of accounting.

Depreciation, depletion and amortization, or DD&A, of capitalized drilling and development costs of oil and natural gas properties are generally computed using the unit of production method on an individual property, field or unit basis based on total estimated proved developed oil and natural gas reserves. Amortization of producing leasehold is based on the unit-of-production method using total estimated proved reserves. In arriving at rates under the unit-of-production method, the quantities of recoverable oil and natural gas are established based on estimates made by our geologists and engineers and independent engineers. Service properties, equipment and other assets are depreciated using the straight-line method over estimated useful lives of 5 to 40 years. Upon sale or retirement of depreciable or depletable property, the cost and related accumulated DD&A are eliminated from the accounts and the resulting gain or loss is recognized.

Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Undeveloped leasehold cost is expensed over the life of the lease or transferred to the associated producing properties. Individually significant non-producing properties are periodically assessed for impairment of value.

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Oil and Natural Gas Reserves and Standardized Measure of Future Cash Flows

Our independent engineers and technical staff prepare the estimates of our oil and natural gas reserves and associated future net cash flows. Current accounting guidance allows only proved oil and natural gas reserves to be included in our financial statement disclosures. The SEC has defined proved reserves as the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Even though our independent engineers and technical staff are knowledgeable and follow authoritative guidelines for estimating reserves, they must make a number of subjective assumptions based on professional judgments in developing the reserve estimates. Reserve estimates are updated at least annually and consider recent production levels and other technical information about each field. Periodic revisions to the estimated reserves and future cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, oil and natural gas prices, cost changes, technological advances, new geological or geophysical data, or other economic factors. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly alter future DD&A and result in impairment of assets that may be material.

Asset Retirement Obligations

In June 2001, the FASB issued SFAS No. 143, which applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and the normal operation of a long-lived asset. The primary impact of this standard on us relates to oil and natural gas wells on which we have a legal obligation to plug and abandon. SFAS No. 143 requires us to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. The determination of the fair value of the liability requires us to make numerous judgments and estimates, including judgments and estimates related to the future salvage value of well equipment, future costs to plug and abandon wells, future inflation rates and estimated lives of the related assets.

Impairment of Assets

All of our long-lived assets are monitored for potential impairment when circumstances indicate that the carrying value of an asset may be greater than its future net cash flows, including cash flows from risk adjusted proved reserves. The evaluations involve a significant amount of judgment since the results are based on estimated future events, such as future sales prices for oil and natural gas, future costs to produce these products, estimates of future oil and natural gas reserves to be recovered and the timing thereof, the economic and regulatory climates and other factors. The need to test a field for impairment may result from significant declines in sales prices or downward revisions to oil and natural gas reserves. Any assets held for sale are reviewed for impairment when we approve the plan to sell. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges will be recorded.

Off-Balance Sheet Arrangements

Currently, we do not have any off-balance sheet arrangements.

Recent Accounting Pronouncements

On December 16, 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 123(R), Share-Based Payment , which is a revision of SFAS No. 123, Accounting for Stock-Based Compensation.

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SFAS No. 123(R) supersedes APB 25 and amends SFAS No. 95, Statement of Cash Flows. Generally, the approach in SFAS No. 123(R) is similar to the approach described in SFAS No. 123. However, SFAS No. 123(R) requires all share-based payments to employees, including grants of employee stock options, be recognized in the consolidated financial statements based on their estimated fair values. Pro forma disclosures are no longer an alternative.

We adopted SFAS 123(R) effective January 1, 2006. So long as we are not a reporting company under Section 12 of the Exchange Act, we have an obligation, and accrue a liability for the amount required, to purchase shares acquired through the exercise of stock options and vested restricted shares at a formula price set forth in the award agreements. As a result of this offering, we will no longer have this purchase obligation, and our equity compensation expense will be based on the valuation methodologies contained in SFAS 123(R).

In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). The interpretation clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes*. The interpretation is effective for fiscal years beginning after December 15, 2006. The adoption of FIN 48 is not expected to have a material impact on our consolidated financial position or results of operations.

In September 2006, the Securities and Exchange Commission issued Staff Accounting Bulletin (SAB) No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Current Year Misstatements*. SAB No. 108 requires analysis of misstatements using both an income statement (rollover) approach and a balance sheet (iron curtain) approach in assessing materiality and provides for a one-time cumulative effect transition adjustment. We have applied the guidance of SAB No. 108 as of December 31, 2006. The application of this SAB had no effect on the consolidated financial statements.

In September 2006, the FASB finalized SFAS No. 157, *Fair Value Measurements* which will become effective in 2008. This Statement defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements; however, it does not require any new fair value measurements. The provisions of SFAS No. 157 will be applied prospectively to fair value measurements and disclosures in our Consolidated Financial Statements beginning in the first quarter of 2008. The adoption of SFAS No. 157 is not expected to have a material impact on our consolidated financial position or results of operations.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115 . This Statement provides entities with an option to choose to measure eligible items at fair value at specified election dates. If elected, an entity must report unrealized gains and losses on the item in earnings at each subsequent reporting date. The fair value option: may be applied instrument by instrument, with a few exceptions, such as investments otherwise accounted for by the equity method; is irrevocable (unless a new election date occurs); and is applied only to entire instruments and not to portions of instruments. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. Management does not believe that the implementation of SFAS No. 159 will have a material impact on our financial statements.

Inflation

Historically, general inflationary trends have not had a material effect on our operating results. However, we have experienced inflationary pressure on technical staff compensation and the cost of oilfield services and equipment due to the increase in drilling activity and competitive pressures resulting from higher oil and natural gas prices in recent years.

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Quantitative and Qualitative Disclosures About Market Risk

We are exposed to a variety of market risks including credit risk, commodity price risk and interest rate risk. We address these risks through a program of risk management which may include the use of derivative instruments.

Credit Risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our oil and natural gas production, which we market to energy marketing companies, refineries and affiliates, as described under Certain relationships and related party transactions. We monitor our exposure to these counterparties primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty s credit worthiness. Although we have not generally required our counterparties to provide collateral to support trade receivables owed to us, we routinely require prepayment of working interest holders proportionate share of drilling costs. For such prepayments, a liability is recorded and subsequently reduced as the associated work is performed. In this manner, we reduce credit risk.

Commodity Price Risk. We are exposed to market risk as the prices of crude oil and natural gas are subject to fluctuations resulting from changes in supply and demand. To partially reduce price risk caused by these market fluctuations, we have hedged in the past, and may hedge in the future, through the utilization of derivatives, including zero-cost collars and fixed price contracts, a portion of our production. We had no hedging contracts in place during 2005 and 2006 and do not currently plan to hedge any of our 2007 production. See the commodity price sensitivity analysis included in Management s Discussion and Analysis of Financial Condition Oil and Natural Gas Prices Realized .

Interest Rate Risk. Our exposure to changes in interest rates relates primarily to long-term debt obligations. We manage our interest rate exposure by limiting our variable-rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We are exposed to changes in interest rates as a result of our credit facility. We had total indebtedness of $269.5 million outstanding under our credit facility at April 12, 2007. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $2.7 million and a corresponding decrease in net income. The fair value of long-term debt is estimated based on quoted market prices and management s estimate of current rates available for similar issues. The following table itemizes our long-term debt maturities and the weighted-average interest rates by maturity date:

	2006	2007	2008	2009	2010	2011	Total
				(in thousands)			
Variable rate debt:							
Credit facility:							
Principal amount	$	$	$	$	$	$ 269,500	$ 269,500
Weighted-average interest rate						6.71%	6.71%

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Business and Properties

Our Business

We are an independent oil and natural gas exploration and production company with operations in the Rocky Mountain, Mid-Continent and Gulf Coast regions of the United States. We focus our exploration activities in large new or developing plays that provide us the opportunity to acquire undeveloped acreage positions for future drilling operations. We have been successful in targeting large repeatable resource plays where horizontal drilling, advanced fracture stimulation and enhanced recovery technologies provide the means to economically develop and produce oil and natural gas reserves from unconventional formations. As a result of these efforts, we have grown substantially through the drillbit, adding 96.2 MMBoe of proved oil and natural gas reserves through extensions and discoveries from January 1, 2001 through December 31, 2006 compared to 5.1 MMBoe added through proved reserve purchases during that same period.

As of December 31, 2006, our estimated proved reserves were 118.3 MMBoe, with estimated proved developed reserves of 87.1 MMBoe, or 74% of our total estimated proved reserves. Crude oil comprised 83% of our total estimated proved reserves. At December 31, 2006, we had 1,772 scheduled drilling locations on the 1,775,000 gross (1,071,000 net) acres that we held. For the year ended December 31, 2006, we generated revenues of $483.7 million, and operating cash flows of $417.0 million.

The following table summarizes our total estimated proved reserves, PV-10 and net producing wells as of December 31, 2006, average daily production for the three months ended December 31, 2006 and the reserve-to-production ratio in our principal regions. Our reserve estimates as of December 31, 2006 are based primarily on a reserve report prepared by Ryder Scott Company, L.P., our independent reserve engineers. In preparing its report, Ryder Scott Company, L.P. evaluated properties representing approximately 83% of our PV-10. Our technical staff evaluated properties representing the remaining 17% of our PV-10.

	At December 31, 2006				Average daily production		
	Proved reserves (MBoe)	Percent of total	PV-10(1) (in millions)	Net producing wells	fourth quarter 2006 (Boe per day)	Percent of total	Annualized reserve/ production index(2)
Rocky Mountain:							
Red River units	66,527	56%	$ 791	201	11,732	44%	15.5
Bakken field	25,623	22%	441	66	7,905	30%	8.9
Other	9,077	8%	104	233	1,717	7%	14.5
Mid-Continent	16,894	14%	244	672	4,280	16%	10.8
Gulf Coast	228		4	19	869	3%	0.7
Total	118,349	100%	$ 1,584	1,191	26,503	100%	12.2

(1) PV-10 is a non GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. However, our PV-10 and our Standardized Measure are equivalent because we are a subchapter S-corporation. In connection with the closing of this offering, we will convert to a subchapter C-corporation. Our pro-forma Standardized Measure, assuming our conversion to a subchapter C-corporation, was $1.0 billion at December 31, 2006. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

(2) The Annualized Reserve/Production Index is the number of years proved reserves would last assuming current production continued at the same rate. This index is calculated by dividing annualized fourth quarter 2006 production into the proved reserve quantity at December 31, 2006.

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The following table provides additional information regarding our key development areas:

	At December 31, 2006					2007 Budget	
	Developed acres		Undeveloped acres		Scheduled drilling locations(1)	Wells planned for drilling	Capital expenditures (in millions)
	Gross	Net	Gross	Net			
Rocky Mountain:							
Red River units	144,309	128,484			133	51	$ 151
Bakken field	81,761	60,176	581,846	342,321	804	58	145
Other	49,010	38,534	375,185	213,516	66	12	13
Mid-Continent	147,681	94,214	335,982	175,780	762	151	122
Gulf Coast	41,450	11,869	17,368	6,360	7	3	6
Total	464,211	333,277	1,310,381	737,977	1,772	275	$ 437

(1) Scheduled drilling locations represent total gross locations specifically identified and scheduled by management as an estimate of our future multi-year drilling activities on existing acreage. Of the total locations shown in the table, 249 are classified as PUDs. As of April 12, 2007, we have commenced drilling 116 locations shown in the table, including 67 PUD locations. Our actual drilling activities may change depending on oil and natural gas prices, the availability of capital, costs, drilling results, regulatory approvals and other factors. See Risk Factors Risks Relating to the Oil and Natural Gas Industry and Our Business.

Our Business Strategy

Our goal is to increase shareholder value by finding and developing crude oil and natural gas reserves at costs that provide an attractive rate of return on our investment. The principal elements of our business strategy are:

Growth Through Low-Cost Drilling. Substantially all of our annual capital expenditures are invested in drilling projects and acreage and seismic acquisitions. From January 1, 2001 through December 31, 2006, proved oil and natural gas reserve additions through extensions and discoveries were 96.2 MMBoe compared to 5.1 MMBoe of proved reserve purchases.

Internally Generate Prospects. Our technical staff has internally generated substantially all of the opportunities for the investment of our capital. Because we have been an early entrant in new or emerging plays, our costs to acquire undeveloped acreage have generally been less than those of later entrants into a developing play. As an example of the cost advantage of entering a play early, our per acre costs for our lease acquisitions in the North Dakota Bakken field during 2003 and 2004 were approximately 80% lower than the per acre costs paid by third parties and by us in the federal and state lease auctions for acreage near our holdings in that area during 2005.

Focus on Unconventional Oil and Natural Gas Resource Plays. Our experience with horizontal drilling, advanced fracture stimulation and enhanced recovery technologies allows us to commercially develop unconventional oil and natural gas resource plays, such as the Red River B dolomite, Bakken Shale and Woodford Shale formations. Production rates in the Red River units also have been increased through the use of enhanced recovery technology. Our production from the Red River units and the Bakken field comprised approximately 74% of our total oil and natural gas production during the three months ended December 31, 2006.

Acquire Significant Acreage Positions in New or Developing Plays. In addition to the 402,000 net acres held in the Montana and North Dakota Bakken field, we held 162,000 net acres in other oil and natural gas shale plays as of December 31, 2006. Our technical staff is focused on identifying and testing new unconventional oil and natural gas resource plays where significant reserves could be developed if commercial production rates can be achieved through advanced drilling, fracture stimulation and enhanced recovery techniques.

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Our Business Strengths

We have a number of strengths that we believe will help us successfully execute our strategies:

Large Drilling and Acreage Inventory. Within the Bakken field, we owned approximately 342,000 net undeveloped acres and had identified over 800 drilling locations as of December 31, 2006. We plan to allocate approximately 38% of our current year capital expenditure budget towards developing our Bakken acreage position. Our large number of identified drilling locations provide for a multi-year drilling inventory.

Within other unconventional plays such as the Lewis Shale in Wyoming, the Woodford Shale in Oklahoma, the New Albany Shale in Kentucky and Indiana and the Marfa Basin in Texas, we owned approximately 162,000 net undeveloped acres as of December 31, 2006.

Additionally, at December 31, 2006, we owned approximately 330,000 net undeveloped acres in other projects, including 35,000 net undeveloped acres in Roosevelt County, Montana on which we are planning a 38-square mile 3-D seismic shoot in 2007, 27,000 net undeveloped acres in the Big Horn Basin in Wyoming, on which we plan to drill 4 wells in 2007, and 24,000 net undeveloped acres in Bowman County, North Dakota, on which we plan to drill 3 horizontal Red River B wells in 2007.

Within the Red River units, we plan to drill 127 horizontal wells and 36 horizontal extensions of existing wellbores over the next two to three years in order to increase the density of both producing and injection wellbores. We believe these operations will increase production and sweep efficiency. Production in the Red River units, as projected by our proved reserve report for the year ended December 31, 2006, is expected to peak in late 2008 at approximately 19,000 net Boe per day. During the three months ended December 31, 2006, production in the Red River units averaged approximately 11,732 net Boe per day.

Horizontal Drilling and Enhanced Recovery Experience. In 1992, we drilled our initial horizontal well, and we have drilled over 350 horizontal wells since that time, which represented more than one-half of our total wells drilled during that period. We also have substantial experience with enhanced recovery methods and currently serve as the operator of 48 waterflood units. Additionally, we operate eight high pressure air injection floods in the United States.

Control Operations Over a Substantial Portion of Our Assets and Investments. As of December 31, 2006, we operated properties comprising 95% of our PV-10. By controlling operations, we are able to more effectively manage the cost and timing of exploration and development of our properties, including the drilling and fracture stimulation methods used.

Experienced Management Team. Our senior management team has extensive expertise in the oil and gas industry. Our Chief Executive Officer, Harold G. Hamm, began his career in the oil and gas industry in 1967. Our seven senior officers have an average of 26 years of oil and gas industry experience. Additionally, our technical staff, which includes 19 petroleum engineers, 12 geoscientists and seven landmen, has an average of more than 19 years experience in the industry.

Strong Financial Position. As of April 12, 2007, we had outstanding borrowings under our credit facility of approximately $269.5 million. We believe that our planned exploration and development activities will be funded substantially from our operating cash flows. After giving effect to this offering at an assumed public offering price of $17.00 per share and the application of the net proceeds we will receive in this offering, we expect to have borrowings of approximately $129.9 million outstanding under our credit facility. As a result of our limited borrowings under our credit facility and strong operational cash flows, we did not enter into any oil or natural gas price hedges for our 2006 production, and we do not currently have plans to hedge any of our 2007 production.

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Conversion to Subchapter C-Corporation

We are currently a subchapter S-corporation under the rules and regulations of the Internal Revenue Service. However, upon the consummation of this offering, we will have more shareholders than the IRS rules and regulations governing S-corporations allow, and therefore, we will convert automatically from a subchapter S-corporation to a subchapter C-corporation. In connection with this conversion, we will record a charge to earnings (estimated to be approximately $178.8 million if the conversion had occurred on December 31, 2006) to recognize deferred taxes.

Proved Reserves

The following table sets forth our estimated proved oil and natural gas reserves, the PV-10 and standardized measure of discounted future net cash flows as of December 31, 2006 by reserve category. Ryder Scott Company, L.P., our independent petroleum engineers, evaluated properties representing approximately 83% of our PV-10, and our technical staff evaluated the remaining properties. Oil and natural gas prices in effect at December 31, 2006, $61.05 per Bbl and $6.30 per MMBtu adjusted for location and quality by field, were used in the computation of future net cash flows.

	Oil (MBbls)	Gas (MMcf)	Total (MBoe)	PV-10(1) (in millions)
Proved developed producing	71,951	69,896	83,600	$ 1,262
Proved developed non-producing	3,385	524	3,472	19
Proved undeveloped	22,702	51,445	31,277	303
Total proved	98,038	121,865	118,349	$ 1,584
Standardized Measure(2)				$ 1,584
Pro Forma Standardized Measure(2)				$ 1,027

(1) PV-10 is a non GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. However, our PV-10 and our Standardized Measure are equivalent because we are a subchapter S-corporation. In connection with the closing of this offering, we will convert to a subchapter C-corporation. Our pro-forma Standardized Measure, assuming our conversion to a subchapter C-corporation, was $1.0 billion at December 31, 2006. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

(2) As of December 31, 2006, Continental Resources was structured as a subchapter S-corporation. Accordingly, no provision for federal or state corporate income taxes has been provided because taxable income is passed through to our shareholders. Pro Forma Standardized Measure assumes Continental Resources was restructured as a subchapter C-corporation as of December 31, 2006.

The following table sets forth our estimated proved reserves, percent of total proved reserves that are proved developed and PV-10 as of December 31, 2006 by region:

	Oil (MBbls)	Gas (MMcf)	Total (MBoe)	% Proved developed	PV-10(1) (in millions)
Rocky Mountain:					
Red River units	60,697	34,980	66,527	75%	$ 791
Bakken field	23,132	14,946	25,623	64%	441
Other	8,039	6,226	9,077	65%	104
Mid-Continent	6,127	64,605	16,894	85%	244
Gulf Coast	43	1,108	228	100%	4
Total	98,038	121,865	118,349	74%	$ 1,584

(1) PV-10 is a non GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. However, our PV-10 and our Standardized Measure are equivalent because we are a subchapter S-corporation. In connection with the closing of this offering, we will convert to a subchapter C-corporation. Our pro-forma Standardized Measure, assuming our conversion to a subchapter C-corporation, was $1.0 billion at December 31, 2006. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

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Production and Price History

The following table sets forth summary information concerning our production results, average sales prices and production costs for the years ended December 31, 2004, 2005 and 2006:

	Year ended December 31,		
	2004	2005	2006
Net production volumes:			
Oil (MBbls)(1)	3,688	5,708	7,480
Natural gas (MMcf)	8,794	9,006	9,225
Oil equivalents (MBoe)	5,154	7,209	9,018
Average prices(1):			
Oil, without hedges ($/Bbl)	$ 38.85	$ 52.45	$ 55.30
Oil, with hedges ($/Bbl)	37.12	52.45	55.30
Natural gas ($/Mcf)	5.06	6.93	6.08
Oil equivalents, without hedges ($/Boe)	36.45	50.19	52.09
Oil equivalents, with hedges ($/Boe)	35.20	50.19	52.09
Costs and expenses(1):			
Production expense ($/Boe)	$ 8.49	$ 7.32	$ 6.99
Production tax ($/Boe)	2.39	2.22	2.48
General and administrative ($/Boe)	2.41	4.34	2.56
DD&A expense ($/Boe)(2)	7.02	6.50	6.91

(1) Oil sales volumes are 21 MBbls less than oil production volumes for the year ended December 31, 2006. Average prices and per unit costs have been calculated using sales volumes.

(2) Rate is determined based on DD&A expense derived from oil and natural gas assets.

The following table sets forth information regarding our average daily production during the fourth quarter of 2006:

	Average daily production fourth quarter 2006		
	Bbls	Mcf	Boe
Rocky Mountain			
Red River units	11,661	428	11,732
Bakken field	7,154	4,506	7,905
Other	1,277	2,638	1,717
Mid-Continent	1,717	15,377	4,280
Gulf Coast	219	3,898	869

Total	22,028	26,847	26,503

Productive Wells

The following table presents the total gross and net productive wells by region and by oil or gas completion as of December 31, 2006:

	Oil wells		Natural gas wells		Total wells	
	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain:						
Red River units	220	201			220	201
Bakken field	116	66			116	66
Other	259	232	3	1	262	233
Mid-Continent	703	546	253	126	956	672
Gulf Coast	7	4	28	15	35	19
Total	1,305	1,049	284	142	1,589	1,191

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Gross wells are the number of wells in which a working interest is owned and net wells are the total of our fractional working interests owned in gross wells. As of December 31, 2006, we owned interests in no wells containing multiple completions.

Developed and Undeveloped Acreage

The following table presents the total gross and net developed and undeveloped acreage by region as of December 31, 2006:

	Developed acres		Undeveloped acres		Total acres	
	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain:						
Red River units	144,309	128,484			144,309	128,484
Bakken field	81,761	60,176	581,846	342,321	663,607	402,497
Other	49,010	38,534	375,185	213,516	424,195	252,050
Mid-Continent	147,681	94,214	335,982	175,780	483,663	269,994
Gulf Coast	41,450	11,869	17,368	6,360	58,818	18,229
Total	464,211	333,277	1,310,381	737,977	1,774,592	1,071,254

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2006 that will expire over the next three years by region unless production is established within the spacing units covering the acreage prior to the expiration dates:

	2007		2008		2009	
	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain:						
Red River units						
Bakken field	99,135	58,471	185,639	100,167	224,382	130,912
Other	82,483	52,036	87,567	44,979	37,997	17,188
Mid-Continent	40,909	22,355	64,527	26,977	66,132	28,250
Gulf Coast	1,788	1,226	9,959	2,046	2,617	2,049
Total	224,315	134,088	347,692	174,169	331,128	178,399

Drilling Activity

During the three years ended December 31, 2006, we drilled exploratory and development wells as set forth in the table below:

	2004		2005		2006	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Oil	12	5.6	13	5.9	17	8.4
Gas	5	0.9	2	1.3	25	4.9
Dry	17	10.5	11	6.9	17	9.4
Total exploratory wells	34	17.0	26	14.1	59	22.7
Development wells:						
Oil	14	8.3	50	30.6	83	57.0
Gas	13	5.7	15	7.6	34	14.5
Dry	4	2.6	3	3.0	7	4.3
Total development wells	31	16.6	68	41.2	124	75.8
Total wells	65	33.6	94	55.3	183	98.5

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As of December 31, 2006, there were 27 gross (15.6 net) development wells and 31 gross (14.2 net) exploratory wells in the process of drilling. As of April 12, 2007, 25 gross (15.0 net) wells of the development wells in process as of December 31, 2006, were completed as producers, and 2 gross (0.6 net) wells were in the process of completion. As of April 12, 2007, 15 gross (4.3 net) wells of the exploratory wells in process as of December 31, 2006 were completed as producers, 1 gross (1.0 net) well was a dry hole and the remaining exploratory wells were drilling or in the process of completion.

As of April 12, 2007, we operated 17 rigs on our properties and have plans to add additional rigs during the next six months. There can be no assurance, however, that additional rigs will be available to us at an attractive cost. See Risk Factors The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

Summary of Oil and Natural Gas Properties and Projects

Rocky Mountain Region

Our properties in the Rocky Mountain region represented 84% of our PV-10 as of December 31, 2006. During the three months ended December 31, 2006, our average production from such properties was 20,092 net Bbls of oil and 7,572 net Mcf of natural gas per day. Our principal producing properties in this region are in the Red River units, the Bakken field and the Big Horn Basin. Additionally, we have prospective acreage for the Lewis Shale in southern Wyoming, another unconventional resource play in the Rocky Mountain Region.

For the six month period ended October 31, 2006, we ranked second among all oil companies in terms of gross operated crude oil production within the Rocky Mountain states of Montana, North Dakota, South Dakota and Wyoming.

Red River Units

Our Red River units represented 59% of our PV-10 in the Rocky Mountain Region as of December 31, 2006 and 55% of our average daily Rocky Mountain Region equivalent production for the three months ended December 31, 2006. The eight units comprising the Red River units are located along the Cedar Hills Anticline in North Dakota, South Dakota and Montana and produce oil and natural gas from the Red River B formation, a thin, continuous, dolomite formation at depths of 8,000 to 9,500 feet. Our Red River units comprise a portion of the Cedar Hills field, listed by the Energy Information Administration in 2004 as the 23rd largest field in the United States ranked by liquids proved reserves.

Cedar Hills Units. The Cedar Hills North unit (CHNU) is located in Bowman and Slope Counties, North Dakota. We drilled the initial horizontal well in the CHNU, the Ponderosa 1-15, in April 1995. As of December 31, 2006, we had drilled 154 horizontal wells within this 49,700-acre unit, with 90 producing wellbores and the remainder serving as injection wellbores. We operate and own a 98% working interest in the CHNU.

The Cedar Hills West unit (CHWU), in Fallon County, Montana, is contiguous to the northern portion of CHNU. As of December 31, 2006, this 7,800-acre unit contained ten horizontal producing wells and four HPAI wells. We operate and own a 100% working interest in the CHWU.

In January 2003, we commenced enhanced recovery in the two Cedar Hills units, with HPAI used throughout most of the area and water injected generally along the boundary of the CHNU. Under HPAI, compressed air injected into a reservoir oxidizes residual oil and produces flue gases (primarily carbon dioxide and nitrogen) that mobilize and sweep the crude oil into producing wellbores. In response to the HPAI and water injection, production from the Cedar Hills units increased to 9,561 net Boe per day in December 2006 from 2,185 net Boe per day in November 2003. As of December 31, 2006, the average density in the Cedar Hill units was

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approximately one producing wellbore each 575 acres. We currently plan to drill 83 new horizontal wellbores and 9 horizontal extensions of existing wellbores in the Cedar Hills units during the next two to three years, increasing the density of both the producing and injection wellbores. We believe this operation will increase production and sweep efficiency. Production in the two units, as projected by our proved reserves report for the year ended December 31, 2006, is expected to peak in late 2008 at approximately 15,400 net Boe per day. In 2007, we plan to invest approximately $95 million drilling in the Cedar Hills units.

On November 8, 2005, we entered into a contract with Hiland Partners, LP (Hiland) for the processing and treatment of gas produced from the CHNU and CHWU. Under the terms of the contract we agree to deliver low pressure gas to Hiland for compression, treatment and processing at a facility to be constructed by Hiland. Nitrogen and carbon dioxide must be removed from the gas production associated with the increasing oil production from CHNU and CHWU for the gas production to be marketable. Under the terms of the contract, we pay $0.60 per Mcf in gathering and treating fees, and 50% of the electrical costs attributable to compression and plant operation and receive 50% of the proceeds from residue gas and plant product sales. After we deliver 36 Bcf of gas, the $0.60 per Mcf gathering and treating fee is eliminated. If the average composite volume of carbon dioxide is less than 10%, we pay an additional $0.10 per Mcf treating fee, otherwise the treating fee is $0.20 per Mcf. The plant is currently expected to be operational in May 2007.

Medicine Pole Hills Units. The Medicine Pole Hills units (MPHU) are approximately five miles east of the southern portion of the CHNU. We acquired the Medicine Pole Hills unit in 1995. At that time, the 9,600- acre unit consisted of 18 vertical producing wellbores and four injection wellbores under HPAI producing 525 net Bbls of oil per day. We have since drilled 33 horizontal wellbores extending production to the west with the formation of the 15,000-acre Medicine Pole Hills West unit and to the south, with the 11,500-acre Medicine Pole Hills South unit. All three units are under HPAI. We operate and own an average 77% working interest in the three units. Production from the units averaged 1,105 net Bbls of oil and 184 net Mcf of natural gas per day in December 2006. We currently plan to drill 16 new horizontal wellbores and seven horizontal extensions of existing wellbores during the next two years, increasing the density of both producing and injection wellbores. We believe these operations will increase production and sweep efficiency. In 2007, we plan to invest approximately $15 million for drilling in MPHU.

Buffalo Red River Units. The three contiguous Buffalo Red River units (Buffalo, West Buffalo and South Buffalo) are located in Harding County, South Dakota, approximately 21 miles south of the MPHU. When we purchased the units in 1995, there were 73 vertical producing wellbores and 38 injection wellbores under HPAI producing approximately 1,906 net Bbls of oil per day. We operate and own an average working interest of 95% in the 32,900 acres comprising the three units. During 2005 and 2006, we re-entered 23 existing vertical wells and drilled horizontal laterals to increase production and sweep efficiency. Production for the month of December 2006 was 1,443 net Bbls of oil per day compared to an average of 1,162 net Bbls of oil per day for the first half of 2005. We currently plan to drill 20 horizontal extensions of existing wellbores and 28 new horizontal wellbores in the Buffalo Red River units over the next three years. We believe these operations will increase production and sweep efficiency. In 2007, we plan to invest $16 million for drilling in the Buffalo Red River units.

Bakken Field

Our properties within the Bakken field in Montana and North Dakota represented 33% of our PV-10 in the Rocky Mountain Region as of December 31, 2006 and 37% of our average daily Rocky Mountain Region equivalent production for the three months ended December 31, 2006. The Bakken formation is widespread and relatively uniform in development throughout the Montana and North Dakota portions of the Williston Basin. The Bakken formation consists of three lithologic members the upper shale, middle member and locally a lower shale. The shales are highly organic, thermally mature and overpressured and act as both a source and

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reservoir for the oil. The middle member is also productive locally and varies in composition from a silty dolomite, to shalely limestone or sand across the Williston Basin. Horizontal drilling and advanced fracture stimulation technologies have enabled commercial recovery from this historically non-commercial reservoir. Generally, the Bakken formation is drilled horizontally on 1,280-acre units to vertical depths ranging from 9,000 to 10,500 feet with opposing horizontal laterals each extending approximately 4,500 feet, for a total drilled footage of approximately 18,000 to 21,000 feet. The wells are typically fracture stimulated to maximize recovery and economic returns.

Richland County, Montana. Commercial production data available on wells completed after February 2001 in the Bakken formation by various operators in Richland County, Montana report 433 productive wells with cumulative production as of October 2006 of 43 MMBbls of oil and 25 Bcf of natural gas. Daily production from these wells for the month of October 2006 was approximately 52 MBbls of oil and 36 MMcf of natural gas.

Our initial well in the Richland County, Montana portion of the Bakken field, the Goss #34-26 completed in August 2003, has produced approximately 218,000 gross Bbls of oil and 100,000 gross Mcf of natural gas as of December 31, 2006 and averaged 75 gross Bbls of oil and 52 gross Mcf of natural gas per day during the month of December 2006. Our average daily rate from 100 gross (59 net) wells in this field was approximately 6,737 net Bbls of oil and 4,372 net Mcf of natural gas during the month of December 2006. Substantially all of our wells have been horizontally drilled on 1,280-acre units within the middle dolomite member, which is well developed under our leasehold in Richland County. In 2006, we drilled several second horizontal wells in 1,280-acre units and plan to drill a horizontal well in 2007 to test the incremental reserves of a third well in a 1,280-acre unit.

As of December 31, 2006, we held 104,000 gross (79,000 net) undeveloped acres in the Richland County, Montana portion of the Bakken field with 39 proved undeveloped and 58 additional scheduled drilling locations. We currently have five operated drilling rigs in this part of the field and plan to invest $57 million in the drilling of 21 horizontal Bakken wells in Montana during 2007.

North Dakota Bakken. Encouraged by the results in Richland County, Montana, operators have begun drilling horizontal wells in the Bakken formation in North Dakota. Since this play is in the early stages of development, results are limited but encouraging. As of December 31, 2006, production data had been reported to the North Dakota Oil and Gas Commission on 86 horizontal North Dakota Bakken wells completed since March 2004. The initial production rates on the 86 wells ranged up to 1,355 Boe per day and averaged 192 Boe per day per well. Cumulative and daily production from the 86 wells as of December 31, 2006 was 2.0 MMBoe and 5,863 Boe, respectively.

As in Richland County, Montana, the upper Bakken shale in western North Dakota is highly organic, thermally mature and over-pressured. Within our North Dakota acreage, the formation is found at vertical depths ranging from 8,500 to 11,000 feet. In North Dakota, the Bakken formation gross interval ranges up to 130 feet compared to about 30 feet in Richland County, Montana. Similarly, the upper Bakken shale thickness ranges up to 20 feet in North Dakota compared to about 7 feet in Richland County, Montana. The middle dolomite member of the Bakken formation in the southern portion of our North Dakota acreage is similar to that present in the Richland County, Montana producing area. Moving north on our acreage, the middle dolomite member increases in thickness but diminishes in reservoir quality. We believe the loss of quality of the middle member is offset by the increasing thickness of the upper and lower shales as one moves north and the strategic position of our acreage along the axis of the Nesson anticline.

In March 2004, we served as contract operator on a well completed in the Bakken formation near the northern border of our acreage. We drilled a 4,376-foot single horizontal lateral within the middle dolomite member of the Bakken Shale in an abandoned dry hole. The well has produced approximately 58,000 gross Boe

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through December 31, 2006 and is estimated to ultimately produce approximately 219,000 gross Boe. The well, initially owned by our principal shareholder and his family, was acquired by us in August 2005.

In October 2004, we completed a well in the Bakken formation on the extreme southeastern edge of our North Dakota acreage in a well originally planned as a shallower Lodgepole formation test. This well is over 120 miles south of our initial test. The well was unsuccessful in the Lodgepole formation and was deepened to test the Bakken formation at this location. The middle dolomite member significantly thins along the southern edge of our acreage and, in this test well, the middle member was essentially not present. The well has produced approximately 17,000 gross Boe through December 31, 2006 from a single 6,199-foot horizontal lateral and is estimated ultimately to produce approximately 32,000 gross Boe.

In 2005, we participated with a small working interest in two non-operated Bakken formation tests in North Dakota. One is expected to ultimately produce about 12,000 gross Boe and the other, 121,000 gross Boe.

In 2006, we participated in 9 gross (4.8 net) operated and 10 gross (1.6 net) non-operated horizontal Bakken Shale wells in North Dakota. Of these, 16 gross (5.2 net) have been completed as producers and the remaining are awaiting completion. Initial production rates for the 16 producing wells ranged from 182 Boe to 1,355 Boe per day.

In June 2006, we entered into an agreement with ConocoPhillips Company to form an area of mutual interest (AMI) within Dunn, McKenzie, Mountrail and Williams Counties, North Dakota and jointly drill wells to test the Bakken formation. Within the AMI, we own approximately 97,000 net acres. Initial wells proposed under the agreement establish exploration blocks covering the 1,280-acre spacing unit for the initial well and two adjacent 1,280-acre spacing units. Each party has the right to acquire from the other party an undivided 50% interest in the exploration block acreage owned by the other party at $500 per net acre. ConocoPhillips Company has proposed and we have agreed to participate in the initial three wells to be drilled under the agreement. As of April 12, 2007, ConocoPhillips Company had three drilling rigs operating within the AMI and we had two drilling rigs operating on our North Dakota Bakken acreage outside the AMI.

As of December 31, 2006, we held 478,000 gross (263,000 net) undeveloped acres in contiguous counties in North Dakota across the state border from the Richland County, Montana drilling activity. During 2007, we plan to invest approximately $71 million in the drilling of 37 horizontal Bakken wells on our acreage in North Dakota.

Big Horn Basin and Other

Our wells within the Big Horn Basin in northern Wyoming and other areas within the Rocky Mountain region represented 8% of our PV-10 in the Rocky Mountain Region as of December 31, 2006 and 8% of our average daily Rocky Mountain Region equivalent production for the three months ended December 31, 2006. During the three months ended December 31, 2006, we produced an average of 1,277 net Bbls of oil and 2,638 net Mcf of natural gas per day from our wells in the Big Horn Basin and other areas within the Rocky Mountain region. Our principal property in the Big Horn Basin, the Worland field, produces primarily from the Phosphoria formation. We have 41 additional proved undeveloped drilling locations in the Worland field. During 2007, we plan to invest approximately $2 million in the drilling of 4 wells in this region.

Lewis Shale Project

As of December 31, 2006, we owned approximately 123,000 gross (31,000 net) undeveloped acres in the Washakie Basin in Carbon and Sweetwater Counties, Wyoming. Our objective is the Lewis Shale, a shale formation up to 1,500 feet thick with thin interbedded and discontinuous siltstones and sandstones. Underlying our acreage, the Lewis Shale is over-pressured, fractured and gas charged with the potential to develop into an economic unconventional gas resource play. Previous drilling in the area has encountered gas from the thick,

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fractured shale, but only the thin, isolated sands within the shale have been produced. As of October 2006, the Triton field, located in the center of our acreage block, has produced a total of 6.7 Bcf of natural gas from 5 wells with up to 40 feet of perforations in thin sands within the Lewis Shale. We plan to produce the entire Lewis Shale sequence with the expectation that ultimate recoveries per well will be greater than previous results.

During 2006, we participated in the drilling of 4 gross (1.3 net) productive wells in the Lewis Shale project. The first well, the CEPO Federal 20-17, was completed in September 2006, has produced approximately 600,000 Mcf of natural gas through March 2007 and produced at an average rate of approximately 4,300 Mcf of natural gas per day in March 2007. The well is producing from the first of two productive sands encountered in the well. The second sand tested at rates of 2,000 Mcf of natural gas per day with flowing pressures of 1,000 pounds per square inch and will be produced at a later date. The second well, the Neptune 13-11, began producing at a rate of approximately 1,200 Mcf of natural gas per day after fracture stimulation in August 2006. The well has produced approximately 173,000 Mcf of natural gas through March 2007 and produced at an average rate of approximately 320 Mcf of natural gas per day in March 2007. The third well, the Barricade 44-1, was completed in December 2006 and produced at an average rate of approximately 320 Mcf of natural gas per day in March 2007. The fourth well, the CEPO Lewis 23-17, is currently being completed and produced at a rate of approximately 4,450 Mcf of natural gas per day on April 12, 2007. We participated in the drilling of a fifth well in the project in 2007 which was abandoned during drilling operations due to mechanical problems. During 2007, we plan to invest approximately $1 million in the drilling of two Lewis Shale wells.

Mid-Continent Region

Our properties in the Mid-Continent Region represented 15% of our PV-10 as of December 31, 2006. During the three months ended December 31, 2006, our average production from such properties was 1,717 net Bbls of oil and 15,377 net Mcf of natural gas per day. Our principal producing properties in this region are located in the Anadarko Shelf of western Oklahoma and the Illinois Basin. We have also acquired acreage in three unconventional resource plays: the Woodford Shale, New Albany Shale and Marfa Basin.

Anadarko Shelf

Our properties within the Anadarko Basin represent 64% of our PV-10 in the Mid-Continent Region as of December 31, 2006 and 63% of our average daily Mid-Continent Region equivalent production for the three months ended December 31, 2006. Our wells within the Anadarko Basin produce from a variety of sands and carbonates in both stratigraphic and structural traps. In 2007, we plan to invest approximately $9 million in the drilling of 6 wells in the Anadarko Basin.

Illinois Basin

Our properties within the Illinois Basin represent 36% of the PV-10 in the Mid-Continent Region as of December 31, 2006 and 37% of our average daily Mid-Continent Region equivalent production for the three months ended December 31, 2006. Our wells within the Illinois Basin produce primarily crude oil from units comprised of shallow sand formations under water injection. In 2007, we plan to invest approximately $4 million in the drilling of 22 wells in the Illinois Basin.

Woodford Shale Project

We owned approximately 91,000 gross (30,000 net) undeveloped acres in Atoka, Coal, Hughes and Pittsburg Counties, Oklahoma as of December 31, 2006. We continue to add to our acreage position and owned approximately 108,000 gross (35,000 net) acres in the Woodford Shale project at March 1, 2007. Our drilling objective is the 100 to 175-foot thick Woodford Shale at vertical depths of 6,000 to 12,500 feet. We believe horizontal drilling, combined with advanced fracture stimulation technology, may provide the means for commercial development of this organic rich, gas-bearing shale. This play is in the early stages of development

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and data is limited. However, we are encouraged by recent drilling results. A total of 72 horizontal Woodford Shale completions have been reported within Atoka, Coal, Hughes and Pittsburg Counties during the past three years with reported initial production rates ranging from 125 to 8,700 Mcf of natural gas per day. The number of rigs drilling horizontal Woodford wells in these counties has increased to 38 as of April 12, 2007. During 2006, we participated in 4 gross (1.3 net) operated and 35 gross (1.8 net) non-operated horizontal Woodford Shale wells. Of these 39 wells, 30 gross (1.6 net) wells have been completed as producers, 7 gross (1.2 net) are drilled and awaiting completion and 2 gross (0.3 net) are being drilled. Initial production rates for the 30 producing wells ranged from 705 Mcf to 8,700 Mcf of natural gas per day and averaged 3,139 Mcf of natural gas per day. In July 2006, we completed a 19 square mile 3D seismic survey over portions of our acreage to identify prospective drilling locations. As of April 12, 2007, we had three operated rigs drilling horizontal Woodford Shale wells and plan to add a fourth rig in May 2007. As of April 12, 2007, we also have working interests in five non-operated wells that are in the process of drilling. We anticipate investing approximately $82 million in the drilling of 123 Woodford Shale wells in 2007.

Marfa Basin Shale Project

In April 2006, we purchased a 50% working interest in approximately 135,000 acres in the Marfa Basin, a lightly explored basin located in Presidio and Brewster Counties, Texas. The Marfa Basin is geologically similar to other gas-prone basins along the Ouachita Overthrust belt, such as the Fort Worth and Arkoma Basins, and is located adjacent to the Delaware Basin where exploration for gas from Barnett equivalent shales is underway by several companies in Culberson County. We are targeting a highly organic and thermally mature sequence of shales up to 600 feet thick that contains Woodford and Barnett equivalent shales. There are no wells producing gas from these shales in the basin. In 2006, we re-entered an existing cased wellbore and tested the productivity of the shales. The well produced natural gas, but at a noncommercial rate. We have not yet determined our 2007 plans for this project.

New Albany Shale Project

We owned approximately 42,000 gross (34,000 net) undeveloped acres in Kentucky and Indiana as of December 31, 2006. Our drilling objective is the New Albany Shale, an organically rich, gas-bearing Devonian age shale equivalent to the prolific Antrim Shale in Michigan. The New Albany Shale averages 100 feet thick under our acreage and is found at vertical depths of 1,500 to 4,500 feet. We believe the potential exists for the New Albany Shale to be an economic unconventional natural gas resource play. In December 2005, we completed our initial horizontal well in the New Albany Shale as an uncommercial producer. We plan to use the core and production data from this well and drilling results of other operators in the play to develop our future drilling plans.

Gulf Coast Region

During the three months ended December 31, 2006, our average production from our Gulf Coast properties was 219 net Bbls of oil and 3,898 net Mcf of natural gas per day. Our principal producing properties in this region are located in South Texas and Louisiana. In 2007, we plan to invest approximately $4 million in the drilling of 3 wells in the Texas and Louisiana Gulf Coast.

Marketing and Major Customers

We principally sell our oil and natural gas production to end users, marketers and other purchasers that have access to nearby pipeline facilities. In areas where there is no practical access to pipelines, oil is transported by truck to storage facilities. Our marketing of oil and natural gas can be affected by factors beyond our control, the

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effects of which cannot be accurately predicted. For a description of some of these factors, see Risk factors Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

For the year ended December 31, 2006, oil sales to Banner and Nexen Marketing U.S.A. Inc. accounted for approximately 14% and 19%, respectively, of our total oil and natural gas sales. No other purchasers accounted for more than 10% of our total oil and gas sales. Banner was an affiliate of ours as described under Certain Relationships and Related Party Transactions. In February 2006, we decided to market the majority of our crude oil in the Rocky Mountain region directly or through a wholly owned subsidiary rather than through an affiliate, and, as Banner has existing contacts and relationships with crude oil purchasers, we decided to purchase Banner. On March 30, 2006, we acquired Banner for approximately $8.8 million, the book value of working capital, principally cash, accounts receivable, crude oil inventory and accounts payable. We believe that the loss of any of these purchasers would not have a material adverse effect on our operations, as there are a number of alternative crude oil purchasers in our producing regions.

Title to Properties

As is customary in the oil and gas industry, we initially conduct only a cursory review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and gas industry. Prior to completing an acquisition of producing oil and natural gas leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion or review previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens to secure borrowings under our credit facility, liens for current taxes and other burdens which we believe do not materially interfere with the use or affect our carrying value of the properties.

Competition

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Our competitors vary within the regions in which we operate, and some of our competitors may possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, shortages or the high cost of drilling rigs could delay or adversely affect our development and exploration operations. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry.

Regulation of the Oil and Natural Gas Industry

Regulation of Transportation of Oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

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Our sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The Federal Energy Regulatory Commission, or the FERC, regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil that allowed for an increase or decrease in the cost of transporting oil to the purchaser. A review of these regulations by the FERC in 2000 was successfully challenged on appeal by an association of oil pipelines. On remand, the FERC in February 2003 increased the index slightly, effective July 2001. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Regulation of Transportation and Sale of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and regulations issued under those Acts by the FERC. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act which removed all Natural Gas Act and Natural Gas Policy Act price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993.

FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, the FERC issued Order No. 636 and a series of related orders to implement its open access policies. As a result of the Order No. 636 program, the marketing and pricing of natural gas have been significantly altered. The interstate pipelines traditional role as wholesalers of natural gas has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although the FERC s orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

In 2000, the FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting. Most pipelines tariff filings to implement the requirements of Order No. 637 have been accepted by the FERC and placed into effect.

We cannot accurately predict whether the FERC s actions will achieve the goal of increasing competition in markets in which our natural gas is sold. Additional proposals and proceedings that might affect the natural gas industry are pending before the FERC and the courts. The natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by the FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of getting gas to point of sale locations.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Regulation of Production

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Environmental, Health and Safety Regulation

General. Our operations are subject to stringent and complex federal, state, local and provincial laws and regulations governing environmental protection, health and safety, including the discharge of materials into the environment. These laws and regulations may, among other things:

require the acquisition of various permits before drilling commences;

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- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas drilling, production and transportation activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise environmental, health and safety laws and regulations, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and gas industry could have a significant impact on our operating costs.

The following is a summary of some of the existing environmental, health and safety laws and regulations to which our business operations are subject.

Waste Handling. The Resource Conservation and Recovery Act, or RCRA, and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the federal Environmental Protection Agency, or EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of crude oil or natural gas are currently regulated under RCRA s non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, in connection with the release of a hazardous substance into the environment. Persons potentially liable under CERCLA include the current or former owner or operator of the site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance to the site where the release occurred. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, damages to natural resources and the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We currently own, lease or operate and have formerly owned, leased or operated numerous properties that have been used for oil and natural gas exploitation and production for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances may have been released on, at or under the properties owned, leased or operated by us, or on, at or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose handling, treatment and disposal of hazardous substances were not under our control. These properties and the substances disposed or released on, at or under them may be subject to CERCLA, RCRA and analogous state laws. Pursuant to such laws, we have in the past performed remediation of spills and releases resulting from our operations. In certain circumstances, we could be required to remove previously disposed substances and wastes,

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remediate contaminated property or perform remedial plugging or pit closure operations to prevent future contamination. In addition, federal and state trustees can also seek substantial compensation for damages to natural resources resulting from spills or releases.

Water Discharges. The Federal Water Pollution Control Act, or the Clean Water Act, and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including oil and other substances generated by our operations, into waters of the United States or state waters. Under these laws, the discharge of pollutants into regulated waters is prohibited except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

The Safe Drinking Water Act, or SDWA, and analogous state laws impose requirements relating to our underground injection activities. Under these laws, the EPA and state environmental agencies have adopted regulations relating to permitting, testing, monitoring, record-keeping and reporting of injection well activities, as well as prohibitions against the migration of injected fluids into underground sources of drinking water. We currently own and operate a number of injection wells, used primarily for re-injection of produced waters, that are subject to SDWA requirements.

Air Emissions. The Federal Clean Air Act and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, EPA and certain states in which we operate have developed and continue to develop stringent regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the Federal Clean Air Act and analogous state laws and regulations.

The Kyoto Protocol to the United Nations Framework Convention on Climate Change became effective in February 2005. Under the Protocol, participating nations are required to implement programs to reduce emissions of certain gases, generally referred to as greenhouse gases, that are suspected of contributing to global warming. The United States is not currently a participant in the Protocol, and Congress has not acted upon recent proposed legislation directed at reducing greenhouse gas emissions. However, there has been support in various regions of the country for legislation that requires reductions in greenhouse gas emissions, and some states have already adopted legislation addressing greenhouse gas emissions from various sources, primarily power plants. The oil and natural gas industry is a direct source of certain greenhouse gas emissions, namely carbon dioxide and methane, and future restrictions on such emissions could impact our future operations. At this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business.

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions that have the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of oil and natural gas projects.

Health, Safety and Disclosure Regulation. We are subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes. The OSHA hazard communication standard, the

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Emergency Planning and Community Right to Know Act and similar state statutes require that we organize and/or disclose information about hazardous materials stored, used or produced in our operations.

We have incurred in the past, and expect to incur in the future, capital and other expenditures related to environmental compliance. Such expenditures, however, are included within our overall capital and operating budgets and are not separately accounted for. Although we believe that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations, we cannot assure you that the passage of more stringent laws or regulations in the future will not have an negative impact on our financial position or results of operations.

Employees

As of December 31, 2006, we employed 299 people, including 166 employees in drilling and production, 45 in financial and accounting, 29 in land, 15 in exploration, 10 in reservoir engineering, 23 in administrative and 11 in information technology. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory. From time to time we utilize the services of independent contractors to perform various field and other services.

Legal Proceedings

We are not a party to any material pending legal proceedings, other than ordinary course litigation incidental to our business. While the ultimate outcome and impact of any proceeding cannot be predicted with certainty, our management believes that the resolution of any proceeding will not have a material adverse effect on our financial condition or results of operations.

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Management

Executive Officers and Directors

The following table sets forth names, ages and titles of our executive officers and directors:

Name	Age	Title
Harold G. Hamm(1)(3)	61	Chairman, Chief Executive Officer and Director
Mark E. Monroe(5)	52	President, Chief Operating Officer and Director
John D. Hart	39	Vice President, Chief Financial Officer and Treasurer
Jeffrey B. Hume	55	Senior Vice President Operations
Tom E. Luttrell	49	Senior Vice President Land
Jack H. Stark(4)	52	Senior Vice President Exploration and Director
Gene R. Carlson	53	Vice President Resource Development
Richard H. Straeter	48	President Illinois Division
Robert J. Grant(2)(5)	68	Director
George S. Littell(3)	62	Director
Lon McCain(1)(2)(5)	59	Director
H. R. Sanders, Jr.(1)(2)(4)	74	Director

(1) Member of the compensation committee.

(2) Member of the audit committee.

(3) Term expires in 2007.

(4) Term expires in 2008.

(5) Term expires in 2009.

Harold G. Hamm has served as Chief Executive Officer and a director since our inception in 1967 and currently serves as Chairman of the board of directors. He serves as Chairman of the board of directors of the general partner of Hiland Partners LP, one of our affiliates and a NASDAQ

publicly traded midstream master limited partnership, and he serves as Chairman of the board of directors of the general partner of Hiland Holdings GP, LP (Hiland Holdings), also publicly traded on NASDAQ. Hiland Holdings owns the general partner interest and units in Hiland Partners LP. He also serves as a director of Complete Production Services, Inc., an NYSE publicly traded oil and gas service company.
Mr. Hamm serves as Chairman of the Oklahoma Independent Petroleum Association. He was President of the National Stripper Well Association and founder and Chairman of Save Domestic Oil, Inc. and served on the Board of the Oklahoma Energy Explorers.

Mark E. Monroe became President and Chief Operating Officer in October 2005 and has served as a member of our board of directors since November 2001. He was Chief Executive Officer and President of Louis Dreyfus Natural Gas Corp. prior to its merger with Dominion Resources, Inc. in October 2001. After the merger, Mr. Monroe was a consultant and served as a member of the board of directors of Unit Corporation, an NYSE publicly traded onshore drilling and oil and gas exploration and production company from October 2003 through October 2005. Prior to the formation of Louis Dreyfus Natural Gas Corp. in 1990, he was Chief Financial Officer of Bogert Oil Company. He has served as Chairman of the Oklahoma Independent Petroleum Association, served on the Domestic Petroleum Council and the National Petroleum Council and on the boards of the Independent Petroleum Association of America, the Oklahoma Energy Explorers and the Petroleum Club of Oklahoma City. Mr. Monroe is a Certified Public Accountant and received his Bachelor of Business Administration degree from the University of Texas at Austin.

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John D. Hart became Vice President, Chief Financial Officer and Treasurer in November 2005. Prior to joining us, he was a Senior Audit Manager with Ernst & Young LLP. Mr. Hart was employed by Ernst & Young LLP from April 1998 to November 2005 and by Arthur Andersen LLP from December 1991 to April 1998. He is a member of the American Institute of Certified Public Accountants, Oklahoma Society of Certified Public Accountants and the Oklahoma Independent Petroleum Association. Mr. Hart graduated from Oklahoma State University with a Masters of Science in Accounting in December 1991.

Jeffrey B. Hume became our Senior Vice President of Operations in November 2006. He was previously elected as Senior Vice President of Resource and Business Development in October 2005, Senior Vice President of Resource Development in July 2002 and served as Vice President of Drilling Operations from 1996 to 2002. Prior to joining us in May 1983 as Vice President of Engineering and Operations, Mr. Hume held various engineering positions with Sun Oil Company, Monsanto Company and FCD Oil Corporation. Mr. Hume is a Registered Professional Engineer and member of the Society of Petroleum Engineers, Oklahoma Independent Petroleum Association and the Oklahoma and National Professional Engineering Societies. Mr. Hume graduated from Oklahoma State University with a Bachelor of Science degree in Petroleum Engineering Technology in 1975.

Tom E. Luttrell joined us as Senior Landman in April 1991 and was promoted to Senior Vice President Land in February 1997. Prior to joining us, Mr. Luttrell was a Senior Landman for Alexander Energy Corp. and Pacific Enterprises Oil Corp. Mr. Luttrell is currently a member of the Oklahoma Independent Petroleum Association legislative affairs committee. He is also a member of the Oklahoma Energy Explorers, American Association of Petroleum Landmen and several regional landman associations. Mr. Luttrell graduated from East Central Oklahoma State University in 1980 with a Bachelor of Business Administration. Mr. Luttrell is a past Chairman of the Northern Alliance of Independent Producers.

Jack H. Stark became Senior Vice President Exploration and a director in May 1998. Prior to joining us as Vice President of Exploration in June 1992, he was the exploration manager for the Western Mid-Continent Region for Pacific Enterprises. From 1978 to 1988, he held various staff and middle management positions with Cities Service Co. and TXO Production Corp. He is a member of the American Association of Petroleum Geologists, Oklahoma Independent Petroleum Association, Rocky Mountain Association of Geologists, Houston Geological Society and Oklahoma Geological Society. Mr. Stark holds a Masters degree in Geology from Colorado State University.

Gene R. Carlson became Vice President Resource Development in October 2005. He was an oil and gas consultant from March 2003 to October, 2005 and a founder and Chief Operating Officer for Encore Acquisition Company from its inception in April 1998 to March 2003. Mr. Carlson graduated from Texas A&M University with a Bachelor of Science degree in Mechanical Engineering.

Richard H. Straeter became President Illinois Division in October 2006. He was previously elected as President of Continental Resources of Illinois, Inc. (CRII) in April 2002. Prior to joining CRII, Mr. Straeter was employed by Barger Engineering, Inc. for 18 years as an engineering consultant and Vice President. He is a Registered Professional Engineer in Indiana, Illinois, Kentucky and Tennessee. Mr. Straeter is a past Chairman of the Illinois Basin Society of Petroleum Engineers and serves as a member of the National Petroleum Council, the Illinois Oil & Gas Association Board and the Ohio, Indiana, Kentucky and Michigan Oil and Gas Associations. Mr. Straeter earned his Bachelor of Science degree in Petroleum Engineering in 1983 and a Professional Engineering Degree (Honorary Masters) in 2004 from the University of Missouri-Rolla.

Robert J. Grant has been a director since January 2006. He was an audit partner of Deloitte & Touche LLP and a predecessor firm from 1969 to 2000. He served as partner in charge of the Dallas, Texas office audit department for ten years and a member of the firm s audit management group for twelve years. He has been a member of the Independent Petroleum Association of America, the American Petroleum Institute and the Texas Independent Producers and Royalty Owners Association and currently is a member of the American Institute of

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Certified Public Accountants and the Texas Society of Certified Public Accountants. Mr. Grant graduated from the University of Detroit with a MBA and BA in accounting.

George S. Littell has been a director since November 2004. He is a partner in the firm of Groppe, Long & Littell, a petroleum consulting firm. Prior to joining the firm in 1975, he held various positions in the natural gas, refining, supply and distribution and gas liquids departments of Mobil Oil Corporation. Mr. Littell received a Bronze Star for his service as an officer in the US Army, Vietnam in 1968-1969. He is a member of the International Association for Energy Economics, an Eagle Scout and a director of the Sam Houston Area Council for the Boy Scouts of America. Mr. Littell graduated from Yale University in 1966 and earned an MBA degree from New York University and a law degree from La Salle Extension University.

Lon McCain has been a director since February 2006. He was appointed a director of Cheniere Energy Partners, GP, LLC, the general partner of Cheniere Energy Partners, L.P., a publicly traded partnership, since April 2007. He was Vice President, Treasurer and Chief Financial Officer of Westport Resources Corporation, a publicly traded exploration and production company, from 2001 until the sale of Westport to Kerr McGee Corporation and his retirement in 2004. From 1992 until joining Westport in 2001, Mr. McCain was Senior Vice President and Principal of Petrie Parkman & Co., an investment banking firm specializing in the oil and gas industry. From 1978 until joining Petrie Parkman, Mr. McCain held senior financial management positions with Presidio Oil Company, Petro-Lewis Corporation and Ceres Capital. He was an Adjunct Professor of Finance at the University of Denver from 1982 through 2005. Mr. McCain currently serves on the board of Crimson Exploration, Inc., a domestic exploration and production company traded on the OTC Bulletin Board, and TransZap, Inc., a privately held provider of accounting software. Mr. McCain received a Bachelor of Business Administration and a Masters of Business Administration/Finance from the University of Denver.

H. R. Sanders, Jr. has been a director since November 2001. He served as a board member of Devon Energy Corporation from 1981 through 2000. In addition, he held the position of Executive Vice President for Devon Energy from 1981 until his retirement in 1997. From 1970 to 1981, Mr. Sanders was a Senior Vice President for Republic Bank of Dallas, N.A. with direct responsibility for independent oil, gas and mining loans. Mr. Sanders is a former member of the Independent Petroleum Association of America, Texas Independent Producers and Royalty Owners Association and Oklahoma Independent Petroleum Association, and a former director of Triton Energy Corporation. He currently serves on the board of Toreador Resources Corporation, a NASDAQ publicly traded oil and gas company with principal operations in France, Romania and Turkey.

Governance Matters

Our board of directors currently consists of seven members. Our directors are divided into three classes serving staggered three-year terms. Class I, Class II and Class III directors will serve until our annual meetings of shareholders in 2007, 2008 and 2009, respectively. At each annual meeting of shareholders, directors will be elected to succeed the class of directors whose terms have expired. This classification of our board of directors could have the effect of increasing the length of time necessary to change the composition of a majority of the board of directors. In general, at least two annual meetings of shareholders will be necessary for shareholders to effect a change in a majority of the members of the board of directors.

After the closing of this offering, we will be a controlled company within the meaning of the listing standards of the NYSE. Consequently, we will not be required to comply with certain of the NYSE s listed company requirements, such as the requirement to have a majority of independent directors on our board or the requirement to have compensation and governance committees comprised entirely of independent directors. However, we will still be required to have an independent audit committee under the NYSE s listed company requirements and will still be subject to SEC rules and regulations governing audit committees. As such, we will be required to have an audit committee consisting of independent directors as defined under the listing standards of the NYSE and under SEC rules and regulations. In addition, at least one member of the audit

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committee of our board of directors must meet the definition of an audit committee financial expert as defined under the SEC rules and regulations.

Board Committees

Our board of directors currently has an audit committee and a compensation committee. Our board may establish other committees from time to time to facilitate our management. Our full board will be responsible for overseeing director nomination and other governance functions.

Audit Committee. The principal functions of the audit committee are to assist the board in monitoring the integrity of our consolidated financial statements, the independent auditor s qualifications and independence, the performance of our independent auditors and our compliance with legal and regulatory requirements. The audit committee will have the sole authority to retain and terminate our independent auditors and to approve the compensation paid to our independent auditors. The audit committee also will be responsible for overseeing our internal audit function. The audit committee currently consists of Messrs. Grant, McCain and Sanders, with Mr. Grant acting as the Chairman. Messrs. Grant, McCain and Sanders are independent under the listing standards of the NYSE and under SEC rules and regulations.

Compensation Committee. The principal functions of the compensation committee are to determine awards to employees of stock or other equity compensation, establish performance criteria for and evaluate the performance of the chief executive officer and approve compensation of all senior executives and directors. The compensation committee is currently comprised of Messrs. Hamm, McCain and Sanders, with Mr. Sanders acting as the Chairman.

Compensation Committee Interlocks and Insider Participation

None of our executive officers has served as a member of a compensation committee (or if no committee performs that function, the board of directors) of any other entity that has an executive officer serving as a member of our board of directors.

Director Compensation

Directors who are not our employees are paid an annual retainer of $25,000 and $1,500 for each regular board of directors meeting attended. The Chairman of the audit committee is paid an additional annual retainer of $10,000, each Chairman of the other committees is paid an annual retainer of $2,500 and committee members other than the Chairman are paid an additional retainer of $1,000. A fee of $750 is paid for each special board meeting and $500 for each committee meeting attended.

Non-employee directors are also annually granted restricted stock with an approximate market value of $40,000 to vest over one year. In January 2006, 3,300 shares of restricted stock were granted each to Messrs. Grant, Littell and Sanders. In February 2006, 3,300 shares of restricted stock were granted to Mr. McCain. In January 2007, 3,300 shares of restricted stock were granted each to Messrs Grant, Littell, Sanders, and McCain.

2006 Director Compensation Table

The following table sets forth the compensation of our outside directors for the year ended December 31, 2006.

Name	Fees Earned or Paid in Cash($)	Stock Awards($)(1)	Total($)
Robert J. Grant	$44,083	$ 29,184	$ 73,267
George S. Littell	31,000	29,184	60,184
Lon McCain	32,499	26,752	59,251
H. R. Sanders Jr.	40,772	29,184	69,956

(1) Stock awards represent the value of restricted stock recognized during 2006. While we are a private company, we are required to purchase vested restricted stock at each director s request at a per share amount derived from our shareholders equity value adjusted quarterly for our PV-10.

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Management members of the board of directors are not compensated separately for their board service.

Compensation Discussion and Analysis

Overview. Prior to the completion of this offering, we have operated as a private company controlled by Harold G. Hamm, our founder, principal shareholder, Chairman of the Board and Chief Executive Officer. From our inception until the formation of the compensation committee in February 2006, Mr. Hamm had been solely responsible for reviewing and approving all compensation decisions relating to our executive officers, including those executive officers named in the Summary Compensation Table under Summary Compensation Table below. Mr. Hamm currently serves as a member of our compensation committee, which is responsible for implementing and administering all aspects of our benefit and compensation plans and programs, as well as developing specific policies regarding compensation of our executive officers.

Compensation Objectives. We are engaged in oil and natural gas exploration and exploitation activities in the Rocky Mountain, Mid-Continent and Gulf Coast regions of the United States. Our primary business goal is to increase shareholder value by finding and developing crude oil and natural gas reserves at costs that provide an attractive rate of return on our investment. We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. We believe that the loss of the services of our senior management or technical personnel could have a material adverse effect on our operations. Accordingly, we have designed our executive compensation program to attract, retain and motivate experienced, talented individuals to achieve our business goal, using the business strategies discussed in greater detail in this prospectus. Please read Business and Properties Our Business Strategy.

Implementing Our Objectives.

Determining Compensation. We rely upon our judgment in making compensation decisions, after reviewing the performance of the company and carefully evaluating an executive s contribution to that performance, including his business responsibilities, current compensation arrangements and long-term potential to enhance shareholder value. Specific operational and financial factors affecting compensation decisions for our named executive officers include reserve additions, finding and development costs, production volume and costs, earnings, cash flow, operating income and return on equity. We have not assigned specific individual goals to our executive officers that are used by the compensation committee in the determination of compensation for such officers.

We do not adhere to rigid formulas in determining the amount and mix of compensation elements. As described below, we rely on the formulaic achievement of financial goals only when establishing the aggregate bonus pool from which bonuses may be paid to all employees. We consider competitive market compensation paid by other companies similar in size and operations to us but we do not attempt to maintain a certain target percentile within that peer group or otherwise exclusively rely on those data to determine executive compensation. We incorporate flexibility into our compensation programs and in the assessment process to respond to and adjust for the evolving business environment.

Peer Compensation Group. The companies included in our compensation peer group (the Peer Group) are Bill Barrett Corporation, Denbury Resources Inc., Encore Acquisition Company, Quicksilver Resources Inc., Range Resources Corp., Southwestern Energy Company and St. Mary Land and Exploration Company. We selected these companies because they are publicly traded exploration and production companies similar in size and operations to us.

Elements of Compensation. The principal elements of the compensation program are a base salary, an annual cash bonus and a long-term incentive award. All cash bonus and equity awards for executive officers have been determined on a discretionary basis and have not been linked to the achievement of specific corporate goals or objectives.

Base Salary. The objective of the base salary component is to pay a competitive wage commensurate with such officer s experience, skills and responsibilities. From January 1, 1999 until September 15, 2004,

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Mr. Hamm elected not to receive a salary or annual bonus. In September 2004, he began to draw an annual salary of $350,000. On January 1, 2006, Mr. Hamm s annual salary was increased to $700,000 after a review of salary amounts paid to the chief executive officers of our Peer Group. The average cash compensation (salary and bonus) paid in 2005 to the highest paid named executive officer as reported in the proxy statements of the Peer Group was approximately $1.3 million compared to $986,539 paid to our CEO in 2006. The base salary of Mark E. Monroe, our President and Chief Operating Officer, was established through negotiations with him in connection with his initial employment in October 2005. Mr. Monroe s base has not been adjusted since such time.

With respect to our other executive officers, Mr. Hamm recommends to the compensation committee for approval the base salaries of the other executive officers generally after completion of an annual performance review conducted after each officer s anniversary hire date. In establishing the base salaries for the other executive officers during 2006, Mr. Hamm and our compensation committee considered the compensation paid to named executive officers by the Peer Group. The aggregate base salaries for our named executive officers, excluding Messrs. Hamm and Monroe, were increased 7.81% during 2006 in order to satisfy our objective of paying salaries at competitive levels. In the future, we expect that the base salaries of the executive officers will be reviewed on an annual basis and adjusted as necessary to remain competitive. We expect that future base salary adjustments for executive officers will be comparable to future adjustments made to executive officer base salaries by the Peer Group.

Annual Cash Bonus. Our executives may earn annual cash bonuses as a reward for our subjective evaluation of their individual contribution to the achievement of annual financial and operating results. The individual cash bonuses paid to executive officers for 2006 and prior years have been determined on a discretionary basis.

Annual cash bonuses are paid from a bonus pool that is equal to 0.375% of net income. Net income is reduced by 35 percent as an adjustment for income taxes not charged against book income because of our S-corporation status. If the conditions described below are met, the annual aggregate bonus pool for executive officers will be equal to 0.375% of earnings before interest expense, depreciation, depletion, amortization and accretion, property impairments, exploration expense and non-cash compensation expense (EBIDA), which results in a larger cash pool from which bonuses may be paid. We consider EBIDA to be a strong indicator of operating performance. The conditions that must be satisfied for the bonus pool to be established based on EBIDA rather than adjusted net income are:

- an increase in equivalent production for the current year compared to the prior year, and
- proved reserve additions from drilling activities of at least 120 percent of production.

During 2006, the first condition was satisfied as production increased 25% over 2005 levels. However, the second condition was not fully achieved as reserve additions from drilling activities were only 111 percent of production. In January 2007, we elected, with the approval of the compensation committee, to fund the bonus pool at 119% of the EBIDA level. In approving the larger bonus pool, our compensation committee considered several operational and financial criteria, including reserve additions, finding and development costs, production volume and costs, earnings, cash flow, operating income and return on equity. The criteria considered are not weighted, but are viewed collectively. The decision to waive the proved reserve condition was consistent with our compensation philosophy of examining several operational and financial criteria in determining annual cash bonuses.

We expect the compensation committee will modify the formal terms of our current bonus plan to be consistent with our compensation philosophy as described below. Therefore, we expect that our annual cash bonus pool will be funded on the basis of EBIDA if warranted by our overall operational, financial and stock performance even though one or both of the current bonus plan conditions are not satisfied.

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The bonus amount for each executive officer is determined at the discretion of the compensation committee. In addition, the compensation committee may elect to award annual cash bonuses to executive officers in an aggregate amount that exceeds the amount calculated from net income or EBIDA. Annual cash bonuses for executive officers are determined after completion of the year-end audited financial statements and reserve report. We have not adopted a policy regarding the adjustment or recovery of previously paid annual cash bonuses in the event our net income or EBIDA, as applicable, are restated or otherwise adjusted in a manner that would have the effect of reducing the size of the aggregate annual cash bonus pool.

In addition to the discretionary annual cash bonus awards made to our executive officers in 2006, an amount of $1,466,844 was accrued for the long-term incentive bonus to be paid to Mr. Monroe in October 2008 pursuant to his employment agreement, which is described in detail below in Employment Agreement. The total amount of the long-term incentive bonus will be paid to Mr. Monroe if he remains employed by us through October 2008. The formula for calculating the long-term incentive bonus was determined through employment agreement negotiations with Mr. Monroe and is reflected in the Non-Equity Incentive Plan Compensation column of the Summary Compensation Table below in Summary Compensation Table.

Long-term Incentive Awards. We did not grant any long-term incentive awards to our executive officers during 2006. We expect that restricted stock awards will be granted in 2007 to executive officers upon completion of our initial public offering approximating the number of prior awards vesting in 2006. Long-term incentive awards have been established to further our goals of retaining and motivating our executive officers. The awards granted to executive officers have been in the form of stock options and restricted stock designed to motivate the executive officers to increase the value of our common stock. The vesting provisions of the awards encourage our officers to remain in our employ in order to realize these forms of compensation. A description of our 2005 Long-Term Incentive Plan and the type of awards that may be granted is discussed below under Employee Benefit Plans. Each of our named executive officers was granted restricted stock vesting over a three-year period during 2005. The number of restricted shares, vesting period and other terms of the 2005 grants to individual executive officers was determined based upon the judgment of Mr. Hamm taking into account the factors described above under Implementing Our Objectives Determining Compensation. The value of unvested equity awards held by an individual was considered in the determination of the 2005 restricted stock awards and we expect that the value of unvested equity awards will be a factor in future awards.

Although our 2005 Long-Term Incentive Plan allows for various equity instruments, we currently intend to make future grants in the form of restricted stock. We intend to grant restricted stock because we believe restricted stock is a stronger motivational tool for employees. Restricted shares provide some value to an employee during periods of stock market volatility, while stock options may have a limited perceived value and may do little to retain and motivate employees when the current value of our stock is less than the option price. We have not established a policy with respect to the timing of long-term incentive awards to executive officers. We have also not adopted any common stock ownership requirements for our executive officers or policies regarding hedging the economic risk of such ownership.

The stock option awards provide for immediate vesting in the event of a change in control of the company, as defined by the 2000 Stock Option Plan, or the death of Mr. Hamm, so long as he holds 35% or more of our stock. The restricted stock awards provide for immediate vesting upon a change in control, as defined by the 2005 Long-Term Incentive Plan. Employees who remain in our employment after a change in control will immediately vest in their stock option and restricted stock awards. We would likely need the assistance of several key employees to successfully conclude a transaction that would result in a change of control. We believe that immediately vesting the awards may serve to reduce concerns, other than continued employment, that such employees may have with respect to any potential change in control transaction and

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may motivate them to complete the transaction. The termination or change-in-control provisions contained in the President s employment agreement are described below under Employment Agreement.

Our 2005 Long-Term Incentive Plan allows for the award of performance units and bonuses that vest upon the achievement of performance targets. The performance targets are based upon operational, financial and stock performance criteria, such as reserve additions, finding and development costs, production volume and costs, earnings, cash flow, operating income, return on equity, stock price appreciation and relative stock price performance. We have not awarded performance units or bonuses under the 2005 Long-Term Incentive Plan and have not determined if we will do so in the future.

Other. We provide automobiles to most executive officers and certain other employees for business and personal use. The personal use is valued according to IRS guidelines and reported as taxable income to the individuals. We value vehicle usage for disclosure in our public filings based on the aggregate incremental cost to us adjusted to reflect each individual s personal use of the vehicle.

We allow Mr. Hamm to use the corporate aircraft for personal trips. The value of such trips is calculated according to IRS guidelines and reported as taxable income to him. Aircraft usage is valued for disclosure in our public filings based on the aggregate incremental cost to us.

We have a defined contribution retirement plan (401(K)) covering all our full-time employees, including our executive officers. Our contributions to the plan are discretionary and based on a percentage of eligible compensation, excluding bonuses. Our contribution to the plan for each eligible employee during 2006 was 5% of such employee s covered compensation up to a maximum of $11,000. We currently plan to maintain the contribution level at 5% for 2007 and future years.

All full-time employees, including our executive officers, may participate in our health and welfare benefit programs, including medical, dental and vision care insurance and disability insurance. We provide all full time employees, including our executive officers, with life insurance coverage of the lesser of 1.5 times base salary or $50,000 and allow them to purchase incremental amounts above this. We do not sponsor any qualified or non-qualified defined benefit plans.

Indemnification Agreements

All of our directors and officers have entered into customary indemnification agreements with us, pursuant to which we have agreed to indemnify our directors and officers to the fullest extent permitted by law.

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Summary Compensation Table

The following table sets forth the compensation of our Principal Executive Officer, Principal Finance Officer, and the other three most highly compensated executive officers. We refer to these five individuals collectively as the named executive officers.

Name and Principal Position	Year	Salary($)	Bonus($)	Stock Awards($)(1)	Option Awards	Non-Equity Incentive Plan Compen-sation($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings($)	All other Compensation($)(2)	Total($)
Harold G. Hamm	2006	$ 686,539	$ 200,000	$ 1,081,409				$ 95,597	$ 2,063,545
Chairman, Chief Executive Officer and Director (Principal Executive Officer)									
Mark E. Monroe	2006	450,000	175,000	953,377		1,466,844(3)		49,537	3,094,758
President, Chief Operating Officer and Director									
John D. Hart	2006	225,577	125,000	230,627				22,764	603,968
Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)									
Jeffrey B. Hume	2006	228,154	160,000	162,277				18,858	569,289
Senior Vice President of Operations									
Jack H. Stark	2006	223,500	155,000	162,277				27,094	567,871
Senior Vice President and Director of Exploration									

(1) Stock Award amounts represent the value of restricted stock vesting during 2006. The associated grants were made during 2005 and vest 33.3 percent on each anniversary beginning in 2006. While we are a private company, we are required to purchase vested restricted stock at each employee s request at a per share amount derived from our shareholders equity value adjusted quarterly for our PV-10 as described in footnotes 1 and 9 to the Notes to Consolidated Financial Statements included elsewhere in this prospectus.

(2) All other compensation includes the following elements:

	Personal use of Company Airplane($)(a)	Personal use of Company Vehicle($)(b)	Company Contributions to 401(K) Plan($)	Cash Dividends Paid on Restricted Stock($)	Total($)
Harold G. Hamm	$ 36,527	$ 7,670	$ 11,000	$ 40,400	$ 95,597
Mark E. Monroe		2,934	11,000	35,603	49,537

John D. Hart	8,165	6,519	8,080	22,764
Jeffrey B. Hume	1,798	11,000	6,060	18,858
Jack H. Stark	10,034	11,000	6,060	27,094

(a) We calculate the incremental cost to the company of any personal use of the corporate aircraft based on the cost of fuel, trip-related maintenance, crew travel expenses, on-board catering, landing fees, trip-related hangar and parking costs, and smaller variable costs. Since the company-owned aircraft are used primarily for business travel, we do not include the fixed costs that do not change based on usage, such as pilots salaries and the purchase costs of the company-owned aircraft.

(b) We calculate the incremental cost to the company of any personal use of the company vehicles, including fuel, maintenance, insurance, lease payments and depreciation, as the vehicles are used primarily for personal use.

(3) Under the terms of his employment agreement, as described below under Employment Agreement, Mr. Monroe is entitled to receive a long-term incentive bonus on October 2, 2008. The bonus is determined by multiplying 193,895 by the excess of $30.91 over the fair market value of our common stock as of October 2, 2008. We value this obligation over the vesting period by the excess of $30.91 over the per share amount derived from our shareholders equity value adjusted quarterly for our PV-10 as described in footnotes 1 and 9 in the Notes to Consolidated Financial Statements included elsewhere in this prospectus. Upon becoming a public company, we will compare $30.91 to the publicly reported price at which our stock closes at each period end. Subject to certain conditions as described herein under Employment Agreement, Mr. Monroe is required to be employed on October 2, 2008, otherwise the bonus is forfeited.

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Outstanding Equity Awards at December 31, 2006

The following table sets forth information regarding stock option and restricted stock held by the named executive officers at December 31, 2006.

	Option Awards				Stock Awards	
	Number of Securities Underlying Unexercised Options(1)					
Name	Exercisable(#)	Unexercisable(#)	Option Exercise Price($)	Option Expiration Date	Number of Shares or Units of Stock that Have Not Vested(#)(2)	Market Value of Shares of Stock That Have Not Vested($)(2)
Harold G. Hamm(3)					146,674	$ 1,296,598
Mark E. Monroe(3)					129,250	1,142,570
John D. Hart(3)					29,337	259,304
Jeffrey B. Hume(3)	132,000		$ 0.64	October 1, 2010	22,000	194,480
	220,000		$ 1.27	October 1, 2010		
Jack H. Stark(3)	132,000		$ 0.64	October 1, 2010	22,000	194,480
	220,000		$ 1.27	October 1, 2010		
	88,000		$ 0.71	April 1, 2012		

(1) None of the named executive officers received grants or exercised stock options during 2006.

(2) Unvested shares will vest ratably on October 3, 2007 and 2008 for Mr. Monroe, October 5, 2007 and 2008, for Messrs Hamm, Hume and Stark, and November 30, 2007 and 2008 for Mr. Hart.

(3) None of the named executive officers are subject to an equity incentive plan.

Option Exercises and Restricted Stock Vested During 2006

The following table sets forth information regarding shares of restricted stock held by the named executive officers which vested during 2006. No options were exercised by the named executive officers during 2006.

Name	Number of Shares Acquired on Vesting(#)	Value Realized on Vesting($)(1)

Harold G. Hamm	73,333	$ 779,589
Mark E. Monroe	64,625	687,081
John D. Hart	14,663	155,894
Jeffrey B. Hume	11,000	116,950
Jack H. Stark	11,000	116,950

(1) Our named executive officers and other recipients of stock grants are only allowed to sell vested grants to us at a formula derived value per share, so long as we are a private company. Value realized on vesting is based on our shareholders equity adjusted for our PV-10 at September 30, 2006, which is the applicable valuation at the time of vesting.

Employee Benefit Plans

2005 Long-Term Incentive Plan

General. In October 2005 and as amended in April 2006, our board of directors and shareholders adopted and approved the Continental Resources, Inc. 2005 Long-Term Incentive Plan (the 2005 Plan). The purpose of the 2005 Plan is to provide our directors and our employees, advisors and consultants additional incentives that are designed to motivate them to put forth maximum effort toward the success and growth of the company and to enable the company and our affiliates to attract and retain experienced individuals. The 2005 Plan provides for the granting of incentive stock options intended to qualify under Section 422 of the Internal Revenue Code, options that do not constitute incentive stock options, restricted stock awards, stock appreciation rights, performance units and performance bonuses.

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Administration. Our board of directors has appointed the compensation committee thereof to administer the 2005 Plan. In general, the compensation committee is authorized to select the recipients of awards, establish the terms and conditions of those awards, accelerate the vesting, exercise or payment of an award or the performance period of an award, and determine to what extent a performance bonus may be deferred. In connection with the adoption of the 2005 Plan, our board of directors terminated our 2000 Stock Option Plan, described below.

Shares Subject to the 2005 Plan and Award Limits. The number of shares of our common stock that may be issued under the 2005 Plan may not exceed 5,500,000, subject to adjustment as described below. Shares of common stock that are attributable to awards that have expired, terminated or been canceled or forfeited, or have otherwise terminated without the issuance of an award, are available for issuance or use in connection with future awards. The maximum number of shares of common stock that may be subject to options and stock appreciation rights granted under the 2005 Plan to any one individual during any calendar year may not exceed 220,000 shares. The maximum number of shares of common stock that may be subject to restricted stock awards and performance unit awards granted under the 2005 Plan to any one individual during any calendar year may not exceed 220,000 shares. The maximum amount of compensation that may be paid under all performance bonuses under the 2005 Plan granted to any one individual during any calendar year may not exceed $1,000,000.

Options. The price at which a share of common stock may be purchased upon exercise of an option granted under the 2005 Plan, whether the option is an incentive stock option or an option that does not constitute an incentive stock option, will be determined by our board of directors or, with respect to awards granted to employees and consultants, the compensation committee, but the purchase price will not be less than the fair market value of a share of common stock on the date the option is granted. Options may be granted independently or in tandem with stock appreciation rights.

Stock Appreciation Rights. Our board of directors may grant stock appreciation rights independently of or in tandem with options to purchase common stock. A stock appreciation right allows the holder to receive, upon exercise of the right, an amount equal to the difference between the fair market value of the shares of our common stock on the exercise date and the exercise price stated in the award. The exercise price of a stock appreciation right can never be less than the fair market value of our common stock on the day of the award. The amount to be received upon exercise of a stock appreciation right will be paid in shares of our common stock.

Restricted Stock. Shares of common stock that are the subject of a restricted stock award under the 2005 Plan will be subject to restrictions on disposition by the holder of such award and an obligation of such holder to forfeit and surrender the shares to us under certain circumstances (the forfeiture restrictions). The forfeiture restrictions will be determined by our board of directors or the compensation committee, as applicable, and may provide that the forfeiture restrictions will lapse upon (a) continuous employment with, or in the case of an award granted to a director or consultant, service to, us or our affiliates, for a specified period of time, (b) the attainment of one or more operational, financial and/or stock performance criteria (the performance criteria) established by the board of directors or the compensation committee, as applicable, that are based on (1) reserve additions or replacements, (2) finding and development costs, (3) production volume, (4) production costs, (5) earnings (including net income or earnings before interest, taxes, depreciation and amortization (EBITDA)), (6) earnings per share, (7) cash flow, (8) operating income, (9) general and administrative expenses, (10) debt to equity ratio, (11) debt to cash flow ratio, (12) debt to EBITDA ratio, (13) EBITDA to interest ratio, (14) return on assets, (15) return on equity, (16) return on invested capital, (17) profit returns/margins, (18) stock price appreciation, (19) total shareholder return, and (20) relative stock price performance, or (c) a combination of any of the foregoing. In addition to acceleration of restricted stock awards upon a change of control of the company, our board of directors or compensation committee, as applicable, may provide that an award accelerates upon an eligible employee s retirement on or after his attainment of age 62, death or disability. Our board of directors may provide that a restricted stock award granted to a director or consultant will accelerate upon his resignation.

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Performance Units. A performance unit award under the 2005 Plan is an award of a monetary unit that may be earned based on performance during a performance period of one year or more. At the time of the grant of a performance unit award, our board of directors or the compensation committee, as applicable, will establish the target, maximum and minimum value of each performance unit, the applicable performance criteria, and time period over which the performance will be measured. Payment of a performance unit award may be in cash or shares of common stock, as determined in the sole discretion of our board of directors.

Performance Bonuses. A performance bonus under the 2005 Plan is an award that provides for a payment that may be earned based on a performance during a period of one year or more. At the time of the grant of a performance bonus under the 2005 plan, our board of directors or the compensation committee, as applicable, will establish the amount that may be earned as a performance bonus under the award and the applicable performance criteria. Payment of a performance bonus award may be in cash or shares of common stock, as determined in the sole discretion of our board of directors or compensation committee, as applicable.

Change of Control. All awards under the 2005 Plan become fully vested, fully earned and exercisable upon the occurrence of a change of control of the company, as defined in the 2005 Plan. The value of the affected awards for our named executive officers as of December 31, 2006 is set forth under Outstanding Equity Awards at December 31, 2006. Additionally, Mr. Monroe is subject to an employment agreement which provides for payment of 2 years of salary and bonus under certain circumstances as described under Employment Agreement.

Amendment and Termination of the 2005 Plan and Awards. The maximum term of any award under the 2005 Plan is 10 years. No awards under the 2005 Plan may be granted after 10 years from its effective date (October 3, 2005). The 2005 Plan will remain in effect until all awards granted under the 2005 Plan have been settled. Our board of directors, in its discretion, may terminate the 2005 Plan at any time with respect to any shares of our common stock for which awards have not been granted. Our board of directors may amend the 2005 Plan in any manner, but any amendment to increase the maximum aggregate number of shares that may be issued under the 2005 Plan (except by operation of the 2005 Plan s adjustment provision), materially modify the class of individuals eligible to receive awards under the 2005 Plan, or materially increase the benefits to participants under the 2005 Plan requires the approval of our shareholders. No change in any award previously granted under the 2005 Plan may be made which would impair the rights of the holder of such award without the consent of the holder. Our board of directors is prohibited from canceling, reissuing or modifying an award under the 2005 Plan if such action will have the effect of repricing the award.

Adjustments. The maximum numbers of shares of common stock that may be issued under the 2005 Plan, and the number of shares subject to any award that has been granted under the 2005 Plan, are subject to adjustment to reflect stock dividends, stock splits, recapitalizations and similar changes in our capital structure. Under the 2005 Plan, we will not make such adjustments unless they would cause at least a 1% increase or decrease in the number of shares subject to any award available under the 2005 Plan.

2000 Stock Option Plan

General. In October 2000, our board of directors and shareholders adopted and approved the Continental Resources, Inc. 2000 Stock Option Plan (the 2000 Plan). In connection with the adoption of the 2005 Plan, our board of directors terminated the 2000 Plan, except with respect to unexercised options outstanding under the 2000 Plan. The purpose of the 2000 Plan was to provide our directors and employees and employees of our affiliates additional incentives that are designed to motivate them to put forth maximum effort toward the success and growth of the company and to enable us and our affiliates to attract and retain experienced individuals. The 2000 Plan provided for the granting of incentive stock options intended to qualify under Section 422 of the Internal Revenue Code and options that do not constitute incentive stock options.

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Administration. In February 2006, our board of directors authorized the compensation committee to administer the 2000 Plan for the purposes of awards previously granted to our employees and employees of our affiliates and consultants. In general, our compensation committee is authorized to select the recipients of options, establish the options terms and conditions, and accelerate such options when to do so would be in the best interest of the company.

Options Granted Under the 2000 Plan. Up to 11,220,000 shares of common stock were originally made available for issuance under the 2000 plan, subject to adjustment as described below. Prior to the termination of the 2000 Plan, options to purchase a total of 2,387,000 shares of common stock were issued. Our board of directors determined the price at which a share of common stock may be purchased upon exercise of an option granted under the 2000 Plan at the time of the grant. In the case of an option that does not constitute an incentive stock option, the exercise price could not be less than 50% of the fair market value of the common stock on the date the option was granted. In the case of an incentive stock option, the exercise price could not be less than 100% of the fair market value of the common stock on the date the option was granted. At the time of the grant of any option or at any time thereafter up until the time of any dividend payment by us, our board of directors could choose to include as part of such award the right to receive dividends or dividend equivalents with respect to such award. The compensation committee has discretion to accelerate the vesting of an option upon the death, disability or termination of the grantee s service to the company under special circumstances (as determined by the compensation committee).

Merger, Dissolution, Change of Control, Death of Harold G. Hamm. If we merge, sell substantially all of our assets or dissolve or liquidate and provision is not made in such transaction for the surviving, resulting or acquiring corporation to assume or substitute our outstanding options, such options will automatically vest and become fully exercisable prior to such transaction. If we undergo a change of control (as defined under the 2000 Plan) or Mr. Hamm dies at a time when 35% or more of the total voting power of our voting stock is beneficially owned by Mr. Hamm (individually and as trustee of his revocable inter vivos trust established in April 1984), then all outstanding options will automatically fully vest.

Amendment and Termination of the 2000 Plan and Awards. The maximum term of any award under the 2000 Plan is 10 years. No change in any option previously granted under the 2000 Plan may be made that would be adverse to the holder of such option without the consent of the holder.

Adjustments. The number of shares subject to any award that has been granted under the 2000 Plan is subject to adjustment to reflect stock dividends, stock splits, recapitalizations and similar changes in our capital structure. Under the 2000 Plan, we will not make such adjustments unless they would cause at least a 1% increase or decrease in the number of shares subject to any option granted under the 2000 Plan.

Employment Agreement

We have entered into an employment agreement with Mark E. Monroe, our President and Chief Operating Officer. The agreement provides for a minimum annual salary of $450,000 during each of the years ended October 2, 2006, 2007 and 2008.

The agreement provides for a long-term incentive bonus payable if Mr. Monroe remains continuously employed by the company through the term of the agreement. The long-term incentive bonus is determined by multiplying 193,875 by the excess of $30.91 over the fair market value of our common stock as of October 2, 2008.

On October 3, 2005, we granted Mr. Monroe 193,875 shares of restricted stock, which vest ratably over a three-year period.

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Payments in the Event of Termination

The employment agreement with Mr. Monroe requires that we pay to him, in a single lump-sum payment (payable as soon as practicable following termination and in compliance with section 409A of the Code), an amount equal to sum of (a) two times his average annual compensation (defined below), and (b) his termination long term bonus amount (as defined below) in the event we terminate him without cause (as defined below) or he resigns for good reason (as defined below).

Mr. Monroe s average annual compensation is the average of his annualized compensation, base salary and bonus, paid under his employment agreement for the two year period of employment (or if employed less than two years, then the period of employment) immediately preceding his date of termination. As of December 31, 2006, Mr. Monroe s average annual compensation was $630,000. As result, under clause (a), Mr. Monroe would have been entitled to a lump-sum payment of $1.26 million as of December 31, 2006.

Mr. Monroe s termination long term bonus amount is the amount equal to the product of (a) 193,875, and (b) the excess of $30.91 over the value of the company s common stock. Until our stock becomes publicly traded, the value of our common stock is the internal valuation based on the book value of our shareholders equity adjusted for PV-10 as of each calendar quarter, which was $8.84 per share as of December 31, 2006. As a result, as of December 31, 2006, Mr. Monroe s termination long term bonus amount would have been $4.28 million.

In addition, we will maintain for the benefit of Mr. Monroe (and his spouse and/or his dependents, as applicable) for a period of 18 months the medical, hospitalization, and dental programs in which he (and his spouse and/or dependents, as applicable) participated immediately prior to his date of termination; provided, however, that if Mr. Monroe (his spouse and/or his dependents, as applicable) is eligible for Medicare or a similar type of governmental medical benefit, such benefit shall be the primary provider before our medical benefits are provided; and provided further, if Mr. Monroe (and his spouse and/or his dependents, as applicable) cannot continue to participate in our programs providing such benefits (e.g., the terms of the plans do not permit participation by former employees), then we will arrange to provide Mr. Monroe (and his spouse and/or his dependents, as applicable) with the economic equivalent of such benefits. Notwithstanding, if Mr. Monroe becomes reemployed with another employer and is eligible to receive medical, hospitalization and dental benefits under another employer-provided plan, the benefits described above will be secondary to those provided under such other plan during the applicable period. As of December 31, 2006, the value of this benefit would have been approximately $24,000.

In the event of the termination of Mr. Monroe s employment as a result of his death or disability he is entitled to his termination long term bonus amount as soon as practicable following such termination.

Mr. Monroe s employment agreement defines cause as: (a) his conviction by a federal or state court of competent jurisdiction of a felony which relates to his employment at the company; (b) an act or acts of dishonesty taken by him and intended to result in substantial personal enrichment to him at the expense of the company; or (c) his willful failure to follow a direct, reasonable and lawful written directive from his supervisor or the board of directors, within the reasonable scope of his duties, which failure is not cured to the satisfaction of the board of directors within thirty (30) days. For purposes of this definition of cause : (x) no act or omission by Mr. Monroe will be deemed willful unless done, or omitted by him in bad faith and without reasonable belief that his action or omission was in the best interest of the company; and (y) Mr. Monroe will not be deemed to have been terminated for cause unless and until the company delivers to him a copy of the resolution duly adopted by the affirmative vote of not less than three-fourths (3/4ths) of the entire membership of the board of directors, at a meeting of the board of directors called and held for such purpose (after reasonable notice to him and an opportunity for him, together with his counsel, to be heard before the board of directors), finding that in the good faith opinion of the board of directors, he was guilty of conduct set forth in clauses (a), (b), or (c) above and specifying the particulars thereof in detail.

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Mr. Monroe s employment agreement defines good reason as: (a) the company s assignment to him of any duties inconsistent in any respect with his position (including status, offices, titles and reporting requirements), authority, duties or responsibilities; (b) the reduction of the rate of his base salary below $450,000 other than as a part of a compensation reduction program which applies equally to all executives at the vice president and above levels; (c) the company requiring him to be based at any office or location outside of the greater Enid, Oklahoma, metropolitan area, except for travel reasonably required in the performance of his responsibilities; or (d) any failure by the company to provide indemnification to him in same manner as provided to other executive officers.

Mr. Monroe s employment agreement also contains standard confidentiality and non-solicitation provisions. In the event of Mr. Monroe s termination by us without cause or by him for good reason, the non-solicitation provision is effective so long as Mr. Monroe is receiving benefits or payments under the employment agreement.

Payments in the Event of Change in Control

In the event of a change in control of the company (as defined below), the unvested shares of restricted stock held by our executive officers will fully vest. This offering will not constitute a change in control of the company.

A change in control means:

(a) any transaction in which shares of voting securities of the company representing more than 50% of the total combined voting power of all outstanding voting securities of the company are issued by the company, or sold or transferred by the shareholders of the company as a result of which those persons and entities who beneficially owned voting securities of the company representing more than 50% of the total combined voting power of all outstanding voting securities of the company immediately prior to such transaction cease to beneficially own voting securities of the company representing more than 50% of the total combined voting power of all outstanding voting securities of the company immediately after such transaction;

(b) the merger or consolidation of the company with or into another entity as a result of which those persons and entities who beneficially owned voting securities of the company representing more than 50% of the total combined voting power of all outstanding voting securities of the company immediately prior to such merger or consolidation cease to beneficially own voting securities of the company representing more than 50% of the total combined voting power of all outstanding voting securities of the surviving corporation or resulting entity immediately after such merger of consolidation; or

(c) the sale of all or substantially all of the company s assets to an entity of which those persons and entities who beneficially owned voting securities of the company representing more than 50% of the total combined voting power of all outstanding voting securities of the company immediately prior to such asset sale do not beneficially own voting securities of the purchasing entity representing more than 50% of the total combined voting power of all outstanding voting securities of the purchasing entity immediately after such asset sale.

Listed in the following table is the value of unvested shares of restricted stock held by our named executive officers as of December 31, 2006, which would fully vest in the event of a change of control. The per share value is the formula price as of December 31, 2006, at which we are required to purchase vested restricted stock upon an holder s request. Also included in the table is the value of termination payments due to Mr. Monroe pursuant to his employment agreement as described under Payments in the Event of Termination.

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Payments in the event of change in control or termination:

	Early Vesting of Restricted Stock	Termination Payment	Total
Harold G. Hamm	$ 1,296,598		$ 1,296,598
Mark E. Monroe	1,142,570	$ 5,562,000	6,704,570
John D. Hart	259,304		259,304
Jeffrey B. Hume	194,480		194,480
Jack H. Stark	194,480		194,480

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Selling Shareholder and Security Ownership of Certain Beneficial Owners and Management

The following table sets forth certain information regarding the beneficial ownership of our common stock prior to and as of the closing of this offering by:

- the selling shareholder and each other person who will beneficially own more than 5% of our common stock then outstanding;
- each of our named executive officers;
- each of our directors; and
- all of our directors and executive officers as a group.

All information with respect to beneficial ownership has been furnished by the respective directors, officers or 5% or more shareholders, as the case may be. The information in the following table gives effect to our 11 for 1 stock split to be effected in the form of a stock dividend concurrent with the consummation of this offering and assumes that the underwriters do not exercise their overallotment option:

	Shares beneficially owned prior to offering				Shares offered hereby	Shares of common stock beneficially owned after offering	
	Voting common stock		Non-voting common stock(1)				
Name of Beneficial Owner	**Number**	**% of class**	**Number**	**% of class**	**Number**	**Number**	**%**
Harold G. Hamm(2)(3)(4)	7,170,526	90.7%	136,460,082(5)	90.2%	20,650,000	122,980,608	73.2%
Harold Hamm DST Trust(3)	439,406	5.6%	8,348,681	5.5%		8,788,087	5.2%
Harold Hamm HJ Trust(4)	292,974	3.7%	5,566,440	3.7%		5,859,414	3.5%
Mark E. Monroe			193,875(6)	*		193,875(6)	*
John D. Hart			39,204(7)	*		39,204(7)	*
Jeffrey B. Hume			385,000(8)	*		385,000(8)	*
Tom E. Luttrell			209,000(9)	*		209,000(9)	*
Jack H. Stark			469,403(10)	*		469,403(10)	*
Gene R. Carlson			36,663(11)	*		36,663(11)	*
Richard H. Straeter			73,326(9)	*		73,326(9)	*
Robert J. Grant			6,600(12)	*		6,600(12)	*

George S. Littell			6,600(12)	*		6,600(12)	*
Lon McCain			6,600(13)	*		6,600(13)	*
H. R. Sanders, Jr.			6,600(12)	*		6,600(12)	*
All directors and executive officers as a group (11 persons)	7,170,526	90.7%	137,892,953(14)	90.5%	20,650,000	124,413,479(14)	74.1%

* Less than 1%.

(1) All shares of non-voting common stock will become voting shares of common stock after the consummation of this offering.

(2) Mr. Hamm holds his shares through the Revocable Inter Vivos Trust of Harold G. Hamm, for which Mr. Hamm is both the trustee and sole beneficiary. The address of the Revocable Inter Vivos Trust of Harold G. Hamm is 302 N. Independence, Enid, Oklahoma 73701.

(3) The Harold Hamm DST Trust is a trust established for the benefit of children of Harold G. Hamm. Mr. Hamm is neither the trustee nor the beneficiary of the Harold Hamm DST Trust. Mr. Hamm disclaims beneficial ownership of the shares of our common stock owned by the Harold Hamm DST Trust, and none of these shares are shown as being beneficially owned by Mr. Hamm in the table above. Mr. Bert Mackie is the trustee of the Harold Hamm DST Trust, and his address is c/o Security National Bank, 201 West Broadway, Enid, Oklahoma 73702-1272.

(4) The Harold Hamm HJ Trust is a trust established for the benefit of children of Harold G. Hamm. Mr. Hamm is neither the trustee nor the beneficiary of the Harold Hamm HJ Trust. Mr. Hamm disclaims beneficial ownership of the shares of our common stock owned by the Harold Hamm HJ Trust, and none of these shares are shown as being beneficially owned by Mr. Hamm in the table above. Mr. Bert Mackie is the trustee of the Harold Hamm HJ Trust, and his address is c/o Security National Bank, 201 West Broadway, Enid, Oklahoma 73702-1272.

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(5) Includes 146,674 shares of restricted stock which vest 50% on each of October 5, 2007 and October 5, 2008.

(6) Includes 129,250 shares of restricted stock which vest 50% on each of October 3, 2007 and October 3, 2008.

(7) Includes 29,337 shares of restricted stock which vest 50% on each of November 30, 2007 and November 30, 2008.

(8) Includes 22,000 shares of restricted stock which vest 50% on each of October 5, 2007 and October 5, 2008, and options to purchase 352,000 shares of our common stock exercisable within 60 days of the date of this prospectus.

(9) Represents shares of non-voting common stock issuable upon the exercise of options to purchase our common stock exercisable within 60 days of the date of this prospectus.

(10) Includes 22,000 shares of restricted stock which vest 50% on each of October 5, 2007 and October 5, 2008, and options to purchase 440,000 shares of our common stock exercisable within 60 days of the date of this prospectus.

(11) Includes 24,442 shares of restricted stock which will vest 50% on each of November 1, 2007 and November 1, 2008.

(12) Represents 3,300 shares of restricted stock granted each in January 2006 and 2007, which vest after a period of one year.

(13) Represents 3,300 shares of restricted stock granted each in February 2006 and January 2007, which vest after a period of one year.

(14) Includes 578,545 shares of restricted stock and options to purchase up to 1,074,326 shares of our non-voting common stock exercisable within 60 days of the date of this prospectus.

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Certain Relationships and Related Party Transactions

In February 2006, our board of directors amended the audit committee charter to require that the audit committee review all related party transactions (as defined below) and recommend approval or disapproval to the board of any such transaction. A related party transaction is a transaction, proposed transaction, or series of similar transactions, in which (a) we are a participant, (b) the amount involved exceeds $120,000 and (c) a related person (as defined below) has or will have a direct or indirect material interest. A related person is (a) any person who is, or at any time since the beginning of our last fiscal year was, a director, executive officer, or nominee to become a director, (b) a person known to be the 5% beneficial owner of any class of our voting securities, (c) an immediate family member of any of the foregoing persons, which means any child, stepchild, parent, stepparent, spouse, sibling, mother-in-law, father-in-law, son-in-law, daughter-in-law, brother-in-law, or sister-in-law of such director, executive officer, nominee for director or more than 5% beneficial owner, and (d) any person (other than a tenant or employee) sharing the household of such director, executive officer, nominee for director or more than 5% beneficial owner. The audit committee considers the adequacy of disclosure and fairness to us of the matters considered. The audit committee adopted a written policy which includes factors for committee members to consider in exercising their judgment including (a) terms of the transaction with the related party, (b) availability of comparable products or services from unrelated third parties, (c) terms available from unrelated third parties and (d) the benefits to us. The audit committee will recommend for approval only those related party transactions that are, in their judgment, in our best interests and on terms no less favorable to us than we could have achieved with an unaffiliated party.

Crude Oil Sales

During the years ended December 31, 2005 and 2006, we sold approximately 1.3 MMBbls and 1.2 MMBbls of oil from properties located in North Dakota and Montana to Banner Pipeline Company, L.L.C. (Banner) for $67.6 million and $61.5 million, respectively. Our principal shareholder and his family trusts owned 100% of the common stock of Banner. Our sales to Banner were based on market prices and considered to be on terms equivalent to arms length transactions. In February 2006, we decided to market the majority of our crude oil in the Rocky Mountain region directly or through a wholly owned subsidiary rather than through an affiliate, and, as Banner has existing contacts and relationships with crude oil purchasers, we decided to purchase Banner. On March 30, 2006, we acquired Banner for approximately $8.8 million, the book value of working capital, principally cash, accounts receivable, crude oil inventory and accounts payable.

During the years ended December 31, 2004 and 2005, we sold approximately 351 MBbls of oil from properties located in Wyoming to Independent Trading & Transportation Company I, L.L.C. or a subsidiary thereof (ITT) for $10.8 million and 263 MBbls for $11.0 million, respectively. Our principal shareholder and his family own 100% of the common stock of ITT. Effective March 2006, we ceased selling oil to ITT. We sold 97 MBbls of oil for $3.7 million during 2006 prior to the cessation of sales to ITT.

We operated crude oil gathering lines in North Dakota and Wyoming on behalf of ITT for which they paid us approximately $236,000, $344,000 and $836,000 during the years ended December 31, 2004, 2005 and 2006, respectively. We paid ITT approximately $398,000, $692,000 and $854,000 for crude oil gathering services in North Dakota during the years ended December 31, 2004, 2005 and 2006, respectively. We believe that our transactions with ITT have been on terms equivalent to arm s-length transactions.

Natural Gas Sales

During the years ended December 31, 2004, 2005 and 2006, we sold approximately 2,394 MMcf for $8.2 million, 4,733 MMcf for $30.3 million and 5,240 MMcf for $29.1 million, respectively, to affiliated natural gas gathering and processing companies owned by our principal shareholder and previous executive officers.

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Additionally, we paid approximately $2.6 million, $10.5 million and $8.4 million for reclaimed oil and residue fuel gas from such companies during the years ended December 31, 2004, 2005 and 2006, respectively. The affiliated natural gas gathering and processing companies were combined into Hiland Partners, LP (Hiland), a publicly traded midstream master limited partnership, in October 2004. Our principal shareholder and his family trusts own the majority of the total outstanding units of Hiland and control its general partner. Our principal shareholder also serves as the Chairman of the Board of Directors of Hiland s general partner. Our sales to and purchases from Hiland are based on market prices and considered to be on terms equivalent to arm s-length transactions. We are generally prohibited, under the terms of an agreement with Hiland, from engaging in the gathering, treating, processing and transportation of natural gas in North America and buying or selling any assets related to the forgoing businesses until February 15, 2010.

On November 8, 2005, we entered into a contract with Hiland for the processing and treatment of gas produced from the CHNU and CHWU. Under the terms of the contract, we agree to deliver low pressure gas to Hiland for compression, treatment and processing at a facility to be constructed by Hiland. Nitrogen and carbon dioxide must be removed from the gas production associated with the increasing oil production from CHNU and CHWU for the gas production to be marketable. Under the terms of the contract, we pay $0.60 per Mcf in gathering and treating fees, and 50% of the electrical costs attributable to compression and plant operation and receive 50% of the proceeds from residue gas and plant product sales. After we deliver 36 Bcf of gas, the $0.60 per Mcf gathering and treating fee is eliminated. If the average composite volume of carbon dioxide is less than 10%, we pay an additional $0.10 per Mcf treating fee, otherwise the treating fee is $0.20 per Mcf. Through December 31, 2006, we have invested $1.7 million and anticipate investing approximately $4.3 million during 2007 to construct gas gathering from each well to central tank battery delivery points. The plant is currently expected to be operational in April 2007. The terms of our contract with Hiland were determined following arm s-length negotiations between our representatives and representatives of Hiland. We believe the terms contained in this agreement are comparable to those we would receive from an unaffiliated third party.

Oilfield Services

During the years ended December 31, 2004, 2005 and 2006, we paid approximately $14.5 million, $20.4 million and $31.4 million, respectively, to affiliated service companies for oilfield services such as saltwater hauling and workover rigs. A portion of such amount was billed to other interest owners. Prior to October 2004, our principal shareholder owned a majority of the common stock of the affiliated service companies. After such date, the assets of the affiliated service companies were conveyed to Complete Production Services, Inc. (Complete). Our principal shareholder serves on the board of directors of Complete and trusts formed by him currently own approximately 7% of the stock of Complete. We believe that our transactions with the affiliated service companies have been on terms no less favorable to us than we could have achieved with an unaffiliated party.

Pursuant to a strategic customer relationship agreement with Complete, we agree to use commercially reasonable efforts to provide the service companies a first right to provide services or supplies required in our operations so long as such services or supplies can be provided on a timely basis and at competitive market prices. The service companies agree to use commercially reasonable efforts to provide us with requested supplies and services ahead of and before any such supplies and services would otherwise be provided to any other customer who is not then being provided supplies and services pursuant to a binding agreement. The strategic customer relationship agreement can be terminated by either party on or after October 2009.

During the years ended December 31, 2004, 2005 and 2006, we paid for costs of approximately $1.2 million, $3.1 million and $5.6 million, respectively, for daywork drilling rig services provided by United Drilling Co. (United). A portion of such amounts was billed to other interest owners. United provided daywork drilling rig services for four wells in 2004, eight wells in 2005 and 11 wells in 2006. Our principal shareholder owns

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100% of the common stock of United. We believe that our transactions with United have been on terms no less favorable to us than we could have achieved with an unaffiliated party.

We signed a Compression Services Agreement effective as of January 28, 2005 with Hiland covering the Cedar Hills North and South Medicine Pole Hills Units whereby Hiland agrees to provide to us on a monthly basis the quantities of compressed air and pressurized water that we request. We have agreed to provide, at no cost to Hiland, all fuel, whether gas or electric, and water, in the quantities necessary for Hiland to provide such services. The term of the contract is for four years from the effective date at a cost of approximately $402,000 per month. In 2004, we were responsible for operating and maintaining the compression equipment and paid Hiland and a predecessor affiliated gas gathering and processing company $3.8 million for rental of the compression equipment. The annual cost of renting the compression equipment was compared against proposals submitted by third parties and the compression equipment rental terms are considered to be no less favorable than we could have achieved with an unaffiliated party. The incremental annual cost of approximately $1 million being paid under the new contract represented our estimate of the annual wages and overhead associated with our eleven employees that operated the compression equipment and the annual cost of maintaining the compression equipment. Under the agreement, Hiland is responsible for operating and maintaining the compression equipment. We did not seek bids from third parties for the operation and maintenance of the compression equipment.

We also signed a Compression Services Agreement effective as of January 28, 2005 with Hiland Partners, GP, LLC (Hiland GP) covering the Medicine Pole Hills Unit and West Medicine Pole Hills Unit whereby Hiland GP agrees to provide compression services. Hiland GP is the general partner of Hiland and our principal shareholder and family trusts own the majority of Hiland GP. We have agreed to provide, at no cost to Hiland GP, all fuel, whether gas or electric, for compression services only, in the quantities necessary for Hiland GP to provide such services. The term is for one year from effective date and automatically renews for additional one-month terms unless terminated by either party upon 15 days notice. During the years ended December 31, 2005 and 2006, we paid $372,000 and $339,000, respectively, to Hiland GP in reimbursement of actual costs incurred by Hiland GP in providing the services. This contract terminated effective June 28, 2006, and we are now providing those services with our employees. Because amounts paid are the actual costs incurred by Hiland GP for the services provided by them, we believe the terms of this agreement were more favorable than the terms we would have received from an unaffiliated party.

During the years ended December 31, 2004, 2005 and 2006, we paid approximately $445,000, $596,000 and $877,000, respectively, for roustabout services to a company owned by a family member of the principal shareholder. During the years ended December 31, 2004, 2005 and 2006, we paid approximately $379,000, $222,000 and $618,000, respectively, to Water Tech LLC, a company majority owned by our principal shareholder, for reclaimed oil and contract labor. We believe that our transactions with these affiliated service companies have been on terms no less favorable to us than we could have achieved with an unaffiliated party.

Sales to Shareholders

In July 2004, we sold all of the outstanding stock in our wholly owned subsidiary Continental Gas Inc. (CGI) to our shareholders for $22.6 million. The sales price was representative of the fair value of the net assets based on an appraisal by an independent third party who also provided us with an opinion of the fairness from a financial point of view of the sale of CGI to the shareholders. These assets represented our entire gas gathering, marketing and processing segment.

Commercial Property Transactions

We lease approximately 67,000 square feet of office space from a company owned by our principal shareholder. Rents under these leases totaled approximately $506,000, $556,000 and $638,000 during the years

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ended December 31, 2004, 2005 and 2006, respectively. The current leases covering this space expire at the end of February 2008 and provide for a total annual rent of approximately $673,000. We believe that our office leases are on terms no less favorable to us than we could have achieved with an unaffiliated party. In December 2005, we paid $253,000 to our principal shareholder to acquire an office building and triplex in Baker, Montana, for which we had previously paid $2,300 per month to lease.

Royalty and Common Ownership

Minerals Acquisitions, LLC (Minerals), wholly owned by our principal shareholder and his wife, owns royalty interests in the Cedar Hills North Unit operated by us. During the years ended December 31, 2004, 2005 and 2006, we paid net oil and gas royalties of approximately $67,000, $155,000 and $31,000, respectively, to Minerals. Effective December 1, 2005 the royalty interests were transferred to the Revocable InterVivos Trust of Harold G. Hamm. Minerals also owns 100% of Jolette Oil (USA) LLC (Jolette), a company formed to acquire undeveloped acreage in the North Dakota Bakken area. In August 2005, we purchased all the assets of Jolette at their book value of $4.5 million. These assets consisted of undeveloped acreage and one producing well in the North Dakota Bakken area.

Wheatland Oil Co. (Wheatland) is owned 75% by our principal shareholder and 25% by another executive officer. Wheatland participates in several of our oil and gas properties with interests generally ranging between 5% and 10% of our interest. During the years ended December 31, 2004, 2005 and 2006, we paid net oil and gas revenues of approximately $1.7 million, $5.4 million and $7.9 million, respectively, and billed costs of approximately $1.4 million, $4.2 million and $5.2 million, respectively, to Wheatland.

Registration Rights Agreement

In connection with the closing of this offering, we will enter into a registration rights agreement with our principal shareholder and the two trusts established for the benefit of Mr. Hamm s children pursuant to which we will grant to our principal shareholder and the trusts certain demand and piggyback registration rights.

Under the registration rights agreement, our principal shareholder and the trusts will each have the right to require us to file a registration statement for the public sale of all of the shares of common stock owned by him or it any time after six months following the date the SEC declares the registration statement of which this prospectus forms a part effective. In addition, if we sell any shares of our common stock in a registered underwritten offering, each of our principal shareholder and the trusts will have the right to include his or its shares in that offering. The underwriters of any such offering will have the right to limit the number of shares to be included in such sale.

We will pay all expenses relating to any demand or piggyback registration, except for underwriters or brokers commission or discounts. The securities covered by the registration rights agreement will no longer be registrable under the registration rights agreement if they have been sold to the public either pursuant to a registration statement or under Rule 144 promulgated under the Securities Act.

Shareholder Note

On November 22, 2004, we entered into a subordinated note with our principal shareholder for $50.0 million at an annual rate of 6.00% interest. During the years ended December 31, 2004 and 2005, we paid approximately $308,000 and $2.9 million in interest on the note, respectively. During 2005, our principal shareholder forgave $2.0 million of the principal amount of the note. The outstanding balance was paid by us in full in December 2005.

After the completion of this offering, the ongoing related party transactions described above and any future additional related party transactions will be reviewed by our audit committee on a regular basis.

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Description of Capital Stock

Concurrent with the closing of this offering, Continental Resources, Inc. will amend and restate its certificate of incorporation and bylaws to increase its authorized capital stock, provide for an 11 for 1 stock split in the form of a stock dividend and add certain other provisions as described below. We will effect the stock split concurrent with the closing of this offering. The information in this section describes our amended and restated certificate of incorporation and bylaws that will be in effect following the closing of this offering and assumes that the stock split has taken place.

The following summary of the capital stock and amended and restated certificate of incorporation and bylaws of Continental Resources, Inc. does not purport to be complete and is qualified in its entirety by reference to the provisions of applicable law and to our amended and restated certificate of incorporation and bylaws, forms of which are filed as exhibits to the registration statement of which this prospectus is a part.

The authorized capital stock of Continental Resources, Inc. will consist of 500,000,000 shares of common stock, $.01 par value per share, and 25,000,000 shares of preferred stock, $.01 par value per share.

Common Stock

As of April 16, 2007, we have 7,902,906 shares of voting common stock and 151,252,893 shares of non-voting common stock outstanding. After this offering, we will have 168,005,799 shares of common stock outstanding, all of which will be voting common stock.

Holders of our common stock will be entitled to one vote for each share held on all matters submitted to a vote of shareholders and do not have cumulative voting rights. Accordingly, holders of a majority of the shares of our common stock entitled to vote in any election of directors may elect all of the directors standing for election.

Holders of our common stock are entitled to receive proportionately any dividends if and when such dividends are declared by our board of directors, subject to any preferential dividend rights of outstanding preferred stock. Upon the liquidation, dissolution or winding up of our company, the holders of our common stock are entitled to receive ratably our net assets available after the payment of all debts and other liabilities and subject to the prior rights of any outstanding preferred stock. Holders of our common stock have no preemptive, subscription, redemption or conversion rights. The rights, preferences and privileges of holders of our common stock are subject to, and may be adversely affected by, the rights of the holders of shares of any series of preferred stock that we may designate and issue in the future.

Our common stock has been approved for listing on the NYSE, subject to official notice of issuance, under the symbol CXP.

Preferred Stock

Under the terms of our amended and restated certificate of incorporation, our board of directors will be authorized to designate and issue shares of preferred stock in one or more series without shareholder approval. Our board of directors has discretion to determine the rights, preferences, privileges and restrictions, including voting rights, dividend rights, conversion rights, redemption privileges and liquidation preferences, of each series of preferred stock. It is not possible to state the actual effect of the issuance of any shares of preferred stock upon the rights of holders of the common stock until the board of directors determines the specific rights of the holders of the preferred stock. However, these effects might include:

restricting dividends on the common stock;

diluting the voting power of the common stock;

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impairing the liquidation rights of the common stock; and

delaying or preventing a change in control of our company.

We have no present plans to issue any shares of preferred stock.

Limitations on Liability and Indemnification of Officers and Directors

Our amended and restated certificate of incorporation will provide that none of our directors shall be personally liable to us or our shareholders for monetary damages for breach of fiduciary duty as a director, except liability for:

any breach of the director s duty of loyalty to us or our shareholders;

acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law;

the payment of unlawful dividends and certain other actions prohibited by the Oklahoma General Corporation Act (the OGCA); and

any transaction from which the director derived any improper personal benefit.

The effect of this provision of our certificate of incorporation will be to eliminate our right and the rights of our shareholders to recover monetary damages against a director for breach of the director s fiduciary duty of care, including breaches resulting from negligent or grossly negligent behavior, except in the situations described above. This provision will not limit or eliminate our rights or the rights of any shareholder to seek non-monetary relief, such as an injunction or rescission in the event of a breach of a director s duty of care.

Our amended and restated bylaws also will provide that we will indemnify officers and directors against losses that they may incur in investigations and legal proceedings resulting from their services to us.

Our amended and restated bylaws also will provide that:

we will be required to indemnify our directors and officers to the fullest extent permitted by Oklahoma law;

we may indemnify our other employees and agents to the extent that we indemnify our officers and directors, unless otherwise required by law, our certificate of incorporation, our bylaws or agreements to which we are a party; and we will be required to advance expenses, as incurred, to our directors and officers in connection with a legal proceeding to the fullest extent permitted by law.

We also have entered into indemnification agreements with each of our current directors and officers to give them additional contractual assurances regarding the scope of the indemnification set forth in our certificate of incorporation and bylaws and to provide additional procedural protections. See Management Indemnification Agreements for a description of such agreements. At present, there is no material pending litigation or proceeding involving any of our directors, officers or employees for which indemnification from us is sought. We are not aware of any threatened litigation that may result in claims for indemnification from us.

We are currently in the process of obtaining liability insurance for our directors and officers that will be effective upon the consummation of this offering.

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Anti-takeover Effects of Provisions of Our Certificate of Incorporation and Bylaws and of Oklahoma Law

Our amended and restated certificate of incorporation and bylaws will contain the following additional provisions, some of which are intended to enhance the likelihood of continuity and stability in the composition of our board of directors and in the policies formulated by our board of directors. In addition, some provisions of the OGCA, if applicable to us, may hinder or delay an attempted takeover without prior approval of our board of directors.

Provisions of our amended and restated certificate of incorporation and bylaws and of the OGCA could discourage attempts to acquire us or remove incumbent management. These provisions could, therefore, prevent shareholders from receiving a premium over the market price for the shares of common stock they hold.

Classified Board. Our amended and restated certificate of incorporation and bylaws will provide that our board of directors be divided into three classes of directors, with the classes to be as nearly equal in number as possible. As a result, approximately one-third of our board of directors will be elected each year. The classification of directors will have the effect of making it more difficult for shareholders to change the composition of our board. Our amended and restated certificate of incorporation and bylaws also will provide that the number of directors will be fixed from time to time exclusively pursuant to a resolution adopted by the board.

Filling Board of Directors Vacancies; Removal. Our amended and restated certificate of incorporation will provide that vacancies and newly created directorships resulting from any increase in the authorized number of directors or any vacancies resulting from death, resignation, retirement, disqualification, removal from office or other cause, may be filled by the affirmative vote of a majority of our directors then in office, though less than a quorum. Each director will hold office until his or her successor is elected and qualified, or until the director s earlier death, resignation, retirement or removal from office. Any director may resign at any time upon written notice to us.

Our amended and restated certificate of incorporation and bylaws will provide that, for so long as Harold G. Hamm, our Chairman, Chief Executive Officer and principal shareholder, and his affiliates own 50% or more of our outstanding shares of common stock, directors may be removed, with or without cause, by the affirmative vote of the holders of a majority of our outstanding shares of common stock. However, from and after the date on which Mr. Hamm and his affiliates cease to own 50% or more of our outstanding shares of common stock, directors may be removed only for cause by affirmative vote of the holders of a majority of our outstanding shares of common stock.

Shareholder Action by Written Consent. Our amended and restated certificate of incorporation will provide that, for so long as Mr. Hamm and his affiliates own 50% or more of our outstanding shares of capital stock entitled to vote in the election of directors, any action required or permitted to be taken by our shareholders may be taken at a duly called meeting of shareholders or by the written consent of shareholders owning the minimum number of shares required to approve the action. However, from and after the date on which Mr. Hamm and his affiliates cease to own 50% or more of our outstanding shares of common stock, shareholders will not be permitted to act by written consent.

Call of Special Meetings. Our amended and restated certificate of incorporation and bylaws will provide that special meetings of our shareholders may be called at any time by the board of directors acting pursuant to a resolution adopted by the board and may not be called by the shareholders.

Advance Notice Requirements for Shareholder Proposals and Director Nominations. Our amended and restated bylaws will provide that shareholders seeking to bring business before or to nominate candidates for

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election as directors at an annual meeting of shareholders must provide timely notice of their proposal in writing to the corporate secretary. With respect to the nomination of directors, to be timely, a shareholder s notice must be delivered to or mailed and received at our principal executive offices (i) with respect to an election of directors to be held at an annual meeting of shareholders, not later than 90 days nor more than 120 days prior to the anniversary date of the proxy statement for the immediately preceding annual meeting of shareholders of the company and (ii) with respect to an election of directors to be held at a special meeting of shareholders, not earlier than 90 days prior to such special meeting and not later than the close of business on the later of the seventieth day prior to such special meeting or the tenth day following the day on which public announcement of the date of the special meeting is first made. With respect to other business to be brought before an annual meeting of shareholders, to be timely, a shareholder s notice must be delivered to or mailed and received at our principal executive offices not later than 90 days nor more than 120 days prior to the anniversary date of the proxy statement for the immediately preceding annual meeting of shareholders of the company. Our amended and restated bylaws also will specify requirements as to the form and content of a shareholder s notice. These provisions may preclude shareholders from bringing matters before an annual meeting of shareholders or from making nominations for directors at an annual meeting of shareholders or may discourage or defer a potential acquirer from conducting a solicitation of proxies to elect its own slate of directors or otherwise attempting to obtain control of us.

No Cumulative Voting. The OGCA provides that shareholders are not entitled to the right to cumulate votes in the election of directors unless our certificate of incorporation provides otherwise. Our amended and restated certificate of incorporation will not expressly provide for cumulative voting. Under cumulative voting, a minority shareholder holding a sufficient percentage of a class of shares may be able to ensure the election of one or more directors.

Authorized but Unissued Shares. Our amended and restated certificate of incorporation will provide that the authorized but unissued shares of common stock and preferred stock are available for future issuance without shareholder approval, subject to various limitations imposed by the New York Stock Exchange. These additional shares may be utilized for a variety of corporate purposes, including future public offerings to raise additional capital, corporate acquisitions and employee benefit plans. The existence of authorized but unissued shares of common stock and preferred stock could make it more difficult or discourage an attempt to obtain control of our company by means of a proxy contest, tender offer, merger or otherwise.

Certificate of Incorporation and Bylaws. Pursuant to the OGCA, our amended and restated certificate of incorporation may not be adopted, repealed or amended, in whole or in part, without the approval of the holders of at least a majority of the outstanding shares of our capital stock. In addition, after such time as Mr. Hamm and his affiliates cease to own 50% or more of our outstanding shares of capital stock entitled to vote in the election of directors, the provision of our certificate of incorporation relating to the classification of our board of directors may not be repealed or amended without the approval of the holders of at least 80% of the outstanding shares of our capital stock entitled to vote in the election of directors.

Our amended and restated certificate of incorporation will permit our board of directors to adopt, amend and repeal our bylaws. Our amended and restated bylaws will provide that our bylaws can be amended by either our board of directors or, as long as Mr. Hamm and his affiliates own 50% or more of our outstanding shares of capital stock entitled to vote in the election of directors, the affirmative vote of the holders of at least a majority of the outstanding shares of our capital stock entitled to vote in the election of directors.

Oklahoma Business Combination Statute. Under the terms of our amended and restated certificate of incorporation and as permitted under the OCGA, we will elect not to be subject to Section 1090.3 of the OGCA, Oklahoma s anti-takeover law. In general this section prevents an interested shareholder from engaging in a

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business combination with us for three years following the date the person became an interested shareholder, unless:

- prior to the date the person became an interested shareholder, our board of directors approved the transaction in which the interested shareholder became an interested shareholder or approved the business combination;
- upon consummation of the transaction that resulted in the interested shareholder becoming an interested shareholder, the interested shareholder owns stock having at least 85% of all voting power at the time the transaction commenced, excluding stock held by our directors who are also officers and stock held by certain employee stock plans; or
- on or subsequent to the date of the transaction in which the person became an interested shareholder, the business combination is approved by our board of directors and authorized at a meeting of shareholders by the affirmative vote of the holders of two-thirds of all voting power not attributable to shares owned by the interested shareholder.

An interested shareholder is defined, generally, as any person that owns stock having 15% or more of all of our voting power, any person that is an affiliate or associate of us and owned stock having 15% or more of all of our voting power at any time within the three-year period prior to the time of determination of interested shareholder status, and any affiliate or associate of such person.

A business combination includes:

- any merger or consolidation involving us and an interested shareholder;
- any sale, lease, exchange, mortgage, pledge, transfer or other disposition to or with an interested shareholder of 10% or more of our assets;
- subject to certain exceptions, any transaction that results in the issuance or transfer by us of any of our stock to an interested shareholder;
- any transaction involving us that has the effect of increasing the proportionate share of the stock of any class or series or voting power owned by the interested shareholder;
- the receipt by an interested shareholder of any loans, guarantees, pledges or other financial benefits provided by or through us; or
- any share acquisition by the interested shareholder pursuant to Section 1090.1 of the OGCA.

Because we will opt out of the Oklahoma anti-takeover law, any interested shareholder could pursue a business combination transaction that is not approved by our board of directors.

Oklahoma Control Share Statute. Under the terms of our amended and restated certificate of incorporation and as permitted under the OGCA, we will elect not to be subject to Sections 1145 through 1155 of the OGCA, Oklahoma s control share acquisition statute. In general, Section 1145 of the OGCA defines control shares as our issued and outstanding shares that, in the absence of the Oklahoma control share statute, would have voting power, when added to all of our other shares that are owned, directly or beneficially, by an acquiring person or over which the acquiring person has the ability to exercise voting power, that would entitle the acquiring person, immediately after the acquisition of the shares to exercise, or direct the exercise of, such voting power in the election of directors within any of the following ranges of voting power:

one-fifth (1/5) or more but less than one-third (1/3) of all voting power;

one-third (1/3) or more but less than a majority of all voting power; or

a majority of all voting power.

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A control share acquisition means the acquisition by any person of ownership of, or the power to direct the exercise of voting power with respect to, control shares. After a control share acquisition occurs, the acquiring person is subject to limitations on the ability to vote such control shares. Specifically, Section 1149 of the OGCA provides that under most control share acquisition scenarios, the voting power of control shares having voting power of one-fifth (1/5) or more of all voting power is reduced to zero unless the shareholders of the issuing public corporation approve a resolution . . . according the shares the same voting rights as they had before they became control shares. Section 1153 of the OGCA provides the procedures for obtaining shareholder consent of a resolution of an acquiring person to determine the voting rights to be accorded the shares acquired or to be acquired in the control share acquisition.

Because we will opt out of the Oklahoma control share statute, any shareholder holding control shares will have the right to vote his or its shares in full in the election of directors.

Registration Rights

In connection with the closing of this offering, we will enter into a registration rights agreement with our principal shareholder and the two trusts established for the benefit of Mr. Hamm s children covering all of the shares of common stock owned by our principal shareholder and the trusts after the closing of this offering. For a description of the registration rights agreement, see Certain Relationships and Related Party Transactions Registration Rights Agreement.

Transfer Agent and Registrar

The transfer agent and registrar for our common stock is American Stock Transfer & Trust Company.

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Shares Eligible for Future Sale

General

Prior to this offering, there has been no public market for our common stock. Sales of substantial amounts of common stock in the open market, including shares issued upon exercise of outstanding options, or the perception that those sales could occur, could adversely affect prevailing market prices and could impair our ability to raise capital in the future through the sale of our equity securities.

Upon completion of the offering, we will have outstanding 168,005,799 shares of our common stock, and outstanding options to purchase 1,418,340 shares of our common stock. All of the 29,500,000 shares sold in the offering, or the 33,925,000 shares if the underwriters exercise their overallotment option in full, will be freely tradable without restriction under the Securities Act, except for any shares purchased by one of our affiliates, as that term is defined under Rule 144 under the Securities Act. All of our outstanding shares other than the shares sold in this offering (a total of 138,505,799 shares, or 134,080,799 shares if the underwriters exercise their overallotment option to purchase additional shares in full) will be restricted securities within the meaning of Rule 144 under the Securities Act and may not be sold other than through registration under the Securities Act or pursuant to an exemption from registration, subject to the restrictions on transfer contained in the lock-up agreements described below and in Underwriting.

Persons who may be deemed affiliates generally include individuals or entities that control, are controlled by or are under common control with us and may include our officers, directors and significant shareholders.

Lock-up Agreements

In connection with this offering, we, Harold G. Hamm, the Harold Hamm DST Trust and the Harold Hamm HJ Trust have agreed that, during the period beginning from the date of this prospectus and continuing to and including the date 180 days after the date of this prospectus, neither we nor any of them will, directly or indirectly, offer, sell, offer to sell, contract to sell or otherwise dispose of any shares of our common stock without the prior written consent of J.P. Morgan Securities Inc. and Merrill Lynch, Pierce, Fenner & Smith Incorporated, with limited exceptions as described under Underwriting. We have been informed by J.P. Morgan Securities Inc. and Merrill Lynch, Pierce, Fenner & Smith Incorporated that they have no present intention to consent to the release of the lock-up restrictions described above. This lock-up will not apply to approximately 2,296,030 shares of restricted stock that are currently held by our employees and directors or issuable upon the exercise of options outstanding under our long-term incentive plan, up to an additional 1,100,000 shares covered by grants that we are permitted to award under our existing long-term incentive plan during the 180-day lock-up period and any shares of common stock purchased by our directors, officers, employees and other persons pursuant to the directed share program. We have directed the underwriters to reserve up to 2,250,000 shares of common stock for sale to such persons at the initial public offering price through the directed share program. See Underwriting for a description of these lock-up arrangements. Upon the expiration of these lock-up agreements, 137,628,109 shares, or 133,203,109 shares if the underwriters exercise their overallotment option in full, will be eligible for sale in the public market under Rule 144 of the Securities Act, subject to volume limitations and other restrictions contained in Rule 144.

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Rule 144

In general, under Rule 144 as currently in effect, beginning 90 days after the date of this prospectus, a person, or persons whose shares are aggregated, who has beneficially owned restricted shares for at least one year, including the holding period of any prior owner (other than an affiliate of ours) would be entitled to sell within any three-month period a number of shares that does not exceed the greater of:

- 1% of the number of shares of common stock then outstanding; or
- the average weekly reported trading volume of the common stock on the NYSE during the four calendar weeks preceding the filing of a Form 144 with respect to the sale.

Sales under Rule 144 also are subject to manner of sale provisions and notice requirements and to the availability of current public information about us.

Rule 144(k)

Under Rule 144(k), a person who is not deemed to have been an affiliate of ours at any time during the three months preceding a sale and who has beneficially owned the shares proposed to be sold for at least two years, including the holding period of any prior owner (other than an affiliate of ours) is entitled to sell those shares without complying with the manner of sale, public information, volume limitation or notice provisions of Rule 144.

Registration Rights

In connection with the closing of this offering, we will enter into a registration rights agreement with our principal shareholder and the two trusts established for the benefit of Mr. Hamm s children covering all of the shares of common stock owned by our principal shareholder and the trusts after the closing of this offering. For a description of the registration rights agreement, see Certain Relationships and Related Party Transactions Registration Rights Agreement.

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Material U.S. Federal Tax Consequences

for Non-U.S. Holders of Our Common Stock

The following is a general discussion of the material U.S. federal income and estate tax consequences to non-U.S. Holders with respect to the acquisition, ownership and disposition of our common stock. In general, a Non-U.S. Holder for purposes of this discussion is any beneficial owner of our common stock other than the following:

an individual citizen or resident of the U.S., including an alien individual who is a lawful permanent resident of the U.S. or meets the substantial presence test under section 7701(b)(3) of the Internal Revenue Code of 1986, as amended (the Code);

a corporation (or an entity treated as a corporation) created or organized in the U.S. or under the laws of the U.S., any state thereof, or the District of Columbia;

a partnership (or an entity treated as a partnership);

an estate, the income of which is subject to U.S. federal income tax regardless of its source; or

a trust, if a U.S. court can exercise primary supervision over the administration of the trust and one or more U.S. persons can control all substantial decisions of the trust, or certain other trusts that have a valid election to be treated as a U.S. person pursuant to the applicable Treasury Regulations.

This discussion is based on current provisions of the Code, final, temporary and proposed Treasury Regulations, judicial opinions, published positions of the Internal Revenue Service, or IRS, and all other applicable administrative and judicial authorities, all of which are subject to change, possibly with retroactive effect. This discussion does not address all aspects of U.S. federal income and estate taxation or any aspects of state, local, or non-U.S. taxation, nor does it consider any specific facts or circumstances that may apply to particular Non-U.S. Holders that may be subject to special treatment under the U.S. federal income tax laws including, but not limited to, insurance companies, real estate investment trusts, regulated investment companies, persons holding our common stock as part of a hedging or conversion transaction or a straddle or other risk-reduction transaction, tax-exempt organizations, pass-through entities, banks or financial institutions, brokers, dealers in securities, and U.S. expatriates. If a partnership or other entity treated as a partnership for U.S. federal income tax purposes is a beneficial owner of our common stock, the tax treatment of a partner in the partnership will generally depend upon the status of the partner and the activities of the partnership. This discussion assumes that the Non-U.S. Holder will hold our common stock as a capital asset, which generally is property held for investment.

Prospective investors are urged to consult their tax advisors regarding the U.S. federal, state and local, and non-U.S. income and other tax considerations of acquiring, holding and disposing of shares of common stock.

Dividends

In general, dividends paid to a Non-U.S. Holder (to the extent paid out of our current or accumulated earnings and profits, as determined under U.S. federal income tax principles) will be subject to U.S. withholding tax at a rate equal to 30% of the gross amount of the dividend, or a lower rate prescribed by an applicable income tax treaty, unless the dividends are effectively connected with a trade or business carried on by the Non-U.S. Holder within the U.S. Under applicable Treasury regulations, a Non-U.S. Holder will be required to satisfy certain certification requirements, generally on IRS Form W-8BEN, or any successor form, directly or through an intermediary, in order to claim a reduced rate of withholding under an applicable income tax treaty. If tax is withheld in an amount in excess of the amount applicable under an income tax treaty, a refund of the excess amount may generally be obtained by filing an appropriate claim for refund with the IRS.

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Dividends that are effectively connected with a U.S. trade or business (and, where an income tax treaty applies, are attributable to a U.S. permanent establishment of the Non-U.S. Holder) generally will not be subject to U.S. withholding tax if the Non-U.S. Holder files the properly completed required forms, including IRS Form W-8ECI, or any successor form, with the payor of the dividend, but instead generally will be subject to U.S. federal income tax on a net income basis in the same manner as if the Non-U.S. Holder were a resident of the U.S. A corporate Non-U.S. Holder that receives effectively connected dividends may be subject to an additional branch profits tax at a rate of 30%, or a lower rate prescribed by an applicable income tax treaty, on its effectively connected earnings and profits, subject to adjustments.

Gain on Sale or Other Disposition of Common Stock

In general, a Non-U.S. Holder will not be subject to U.S. federal income tax on any gain realized upon the sale or other taxable disposition of the Non-U.S Holder s shares of common stock unless:

- the gain is effectively connected with a trade or business carried on by the Non-U.S. Holder within the U.S. (and, where an income tax treaty applies, is attributable to a U.S. permanent establishment of the Non-U.S. Holder), in which case the branch profits tax discussed above may also apply if the Non-U.S. Holder is a corporation;
- the Non-U.S. Holder is an individual who holds shares of common stock as capital assets and is present in the U.S. for 183 days or more in the taxable year of disposition and certain other conditions are met; or
- we are or have been a U.S. real property holding corporation for U.S. federal income tax purposes during specified periods.

A Non-U.S. Holder described in the first and third bullet points above will be subject to tax on the net gain derived from the sale under regular graduated U.S. federal income tax rates. A Non-U.S. Holder described in the second bullet point above will be subject to a 30% tax on the gain derived from the sale, which may be offset by U.S. source capital losses.

Because of the oil and natural gas properties and other real property assets we own, we may be a U.S. real property holding corporation. The determination of whether we are a U.S. real property holding corporation is fact specific and depends on the composition of our assets. Generally, a corporation is a U.S. real property holding corporation if the fair market value of its U.S. real property interests, as defined in the Internal Revenue Code and applicable regulations, equals or exceeds 50% of the aggregate fair market value of its worldwide real property interests and its other assets used or held for use in a trade or business. If we are, have been, or become, a U.S. real property holding corporation, and our common stock is regularly traded on an established securities market, a Non-U.S. Holder who (actually or constructively) holds or held (at anytime during the shorter of the five year period preceding the date of dispositions or the holder s holding period) more than five percent of our common stock would be subject to U.S. federal income tax on a disposition of our common stock, but other Non-U.S. Holders generally would not be. If our common stock is not so traded, all Non-U.S. Holders would be subject to U.S. federal income tax on disposition of our common stock.

You are encouraged to consult your own tax advisor regarding our possible status as a U.S. real property holding corporation and its possible consequences in your particular circumstances.

Information Reporting and Backup Withholding

Generally, we must report annually to the IRS the amount of dividends paid, the name and address of the recipient, and the amount, if any, of tax withheld. A similar report is sent to the recipient. These information reporting requirements apply even if withholding was not required because the dividends were effectively

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connected dividends or withholding was reduced by an applicable income tax treaty. Under income tax treaties or other agreements, the IRS may make its reports available to tax authorities in the recipient s country of residence.

Dividends paid to a Non-U.S. Holder that is not an exempt recipient generally will be subject to backup withholding, currently at a rate of 28% of the gross proceeds, unless a Non-U.S. Holder certifies as to its foreign status, which certification may be made on IRS Form W-8BEN.

Proceeds from the disposition of common stock by a Non-U.S. Holder effected by or through a U.S. office of a broker will be subject to information reporting and backup withholding, currently at a rate of 28% of the gross proceeds, unless the Non-U.S. Holder certifies to the payor under penalties of perjury as to, among other things, its address and status as a Non-U.S. Holder or otherwise establishes an exemption. Generally, U.S. information reporting and backup withholding will not apply to a payment of disposition proceeds if the transaction is effected outside the U.S. by or through a non-U.S. office. However, if the broker is, for U.S. federal income tax purposes, a U.S. person, a controlled foreign corporation, a foreign person who derives 50% or more of its gross income for specified periods from the conduct of a U.S. trade or business, specified U.S. branches of foreign banks or insurance companies or a foreign partnership with various connections to the U.S., information reporting, but not backup withholding, will apply unless:

the broker has documentary evidence in its files that the holder is a Non-U.S Holder and certain other conditions are met; or

the holder otherwise establishes an exemption.

Backup withholding is not an additional tax. Rather, the amount of tax withheld is applied as a credit to the U.S. federal income tax liability of persons subject to backup withholding. If backup withholding results in an overpayment of U.S. federal income taxes, a refund may be obtained, provided the required documents are timely filed with the IRS.

Estate Tax

Our common stock owned or treated as owned by an individual who is not a citizen or resident of the U.S. (as specifically defined for U.S. federal estate tax purposes) at the time of death will be includible in the individual s gross estate for U.S. federal estate tax purposes, unless an applicable estate tax treaty provides otherwise.

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Underwriting

We and the selling shareholder are offering the shares of common stock described in this prospectus through a number of underwriters. J.P. Morgan Securities Inc. and Merrill Lynch, Pierce, Fenner & Smith Incorporated are acting as joint book-running managers of the offering and as representatives of the underwriters. We and the selling shareholder have entered into an underwriting agreement with the underwriters. Subject to the terms and conditions of the underwriting agreement, we and the selling shareholder have severally agreed to sell to the underwriters, and each underwriter has severally agreed to purchase, at the public offering price less the underwriting discount set forth on the cover page of this prospectus, the number of shares of common stock listed next to its name in the following table:

Name	Number of shares
J.P. Morgan Securities Inc.	
Merrill Lynch, Pierce, Fenner & Smith Incorporated	
Citigroup Global Markets Inc.	
UBS Securities LLC	
Deutsche Bank Securities, Inc.	
Raymond James & Associates, Inc.	
Total	29,500,000

The underwriters are committed to purchase all the shares of common stock offered by us and the selling shareholder if they purchase any shares. The underwriting agreement provides that if an underwriter defaults, the purchase commitments of non-defaulting underwriters may be increased or the offering may be terminated. The underwriting agreement also provides that the obligations of the underwriters are subject to certain conditions precedent, including the absence of any material adverse change in our business and the receipt of certain certificates, opinions and letters from us, the selling shareholder, our counsel and our independent auditors.

The underwriters propose to offer the shares of common stock directly to the public at the initial public offering price set forth on the cover page of this prospectus and to certain dealers at that price less a concession not in excess of $ per share. Any such dealers may resell shares to certain other brokers or dealers at a discount of up to $ per share from the initial public offering price. After the initial public offering of the shares, the offering price and other selling terms may be changed by the underwriters. Sales of shares made outside of the United States may be made by affiliates of the underwriters. The representatives have advised us and the selling shareholder that the underwriters do not intend to confirm discretionary sales in excess of 5% of the shares of common stock offered in this offering.

The underwriters have an option to buy up to 4,425,000 additional shares of common stock from the selling shareholder to cover sales of shares by the underwriters which exceed the number of shares specified in the table above. The underwriters have 30 days from the date of this prospectus to exercise this overallotment option. If any shares are purchased with this overallotment option, the underwriters will purchase shares in approximately the same proportion as shown in the table above. If any additional shares of common stock are purchased, the underwriters will offer the additional shares on the same terms as those on which the shares are being offered.

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The underwriting fee is equal to the public offering price per share of common stock less the amount paid by the underwriters per share of common stock. The underwriting fee is $ per share. The following table shows the per share and total underwriting discount that we and the selling shareholder will pay to the underwriters assuming both no exercise and full exercise of the underwriters overallotment option to purchase additional shares:

	Without overallotment exercise	With full overallotment exercise
Per share	$	$
Total	$	$

We estimate that the total expenses of this offering, including registration, filing and listing fees, printing fees and legal and accounting expenses, but excluding the underwriting discount, will be approximately $1.9 million, all of which will be paid by us.

We have directed the underwriters to reserve up to 2,250,000 shares of common stock for sale to our directors, officers, employees and other persons at the initial public offering price through a directed share program. The number of shares of common stock available for sale to the general public in the public offering will be reduced to the extent these persons purchase any reserved shares. Any shares not so purchased will be offered by the underwriters to the general public on the same basis as other shares offered hereby.

A prospectus in electronic format may be made available on the web sites maintained by one or more underwriters, or selling group members, if any, participating in the offering. Other than the prospectus in electronic format, the information on such web sites is not part of this prospectus. The underwriters may agree to allocate a number of shares to underwriters and selling group members for sale to their online brokerage account holders. Internet distributions will be allocated by the representatives to underwriters and selling group members that may make Internet distributions on the same basis as other allocations.

We, Harold G. Hamm, the Harold Hamm DST Trust and the Harold Hamm HJ Trust have agreed that, without the prior written consent of J.P. Morgan Securities Inc. and Merrill Lynch, Pierce, Fenner & Smith Incorporated, neither we nor any of them will, with limited exceptions as described below, during the period ending 180 days after the date of this prospectus,

offer, pledge, announce the intention to sell, grant any option, right or warrant to purchase, or otherwise transfer or dispose of, directly or indirectly, any shares of our common stock (including, without limitation, common stock which may be deemed to be beneficially owned by such directors, officers and shareholders in accordance with the rules and regulations of the SEC and securities which may be issued upon exercise of a stock option or warrant) or any securities convertible into or exercisable or exchangeable for common stock; or

request or demand that we file a registration statement related to the common stock; or

enter into any swap or other agreement that transfers, in whole or in part, any of the economic consequences of ownership of the common stock, whether any such transaction described above is to be settled by delivery of common stock or such other securities, in cash or otherwise. Notwithstanding the foregoing, we will be able to grant awards under our existing long-term incentive plan covering up to 1,100,000 shares of our common stock during the lock-up period. These shares will not be subject to the lock-up restrictions described above.

In the event that (1) during the last 17 days of the 180-day restricted period, we issue an earnings release or material news or a material event relating to our company occurs; or (2) prior to the expiration of the 180-day restricted period, we announce that we will release earnings results during the 16-day period beginning on the

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last day of the 180-day period, the restrictions described above shall continue to apply until the expiration of the 18-day period beginning on the issuance of the earnings release or the occurrence of the material news or material event.

We have been informed by J.P. Morgan Securities Inc. and Merrill Lynch, Pierce, Fenner & Smith Incorporated that they have no present intention to consent to the release of the lock-up restrictions described above.

We and the selling shareholder have agreed to indemnify the underwriters against certain liabilities, including liabilities under the Securities Act of 1933.

Our common stock has been approved for listing on the New York Stock Exchange, subject to official notice of issuance, under the symbol CXP.

In connection with this offering, the underwriters may engage in stabilizing transactions, which involves making bids for, purchasing and selling shares of common stock in the open market for the purpose of preventing or retarding a decline in the market price of the common stock while this offering is in progress. These stabilizing transactions may include making short sales of the common stock, which involves the sale by the underwriters of a greater number of shares of common stock than they are required to purchase in this offering, and purchasing shares of common stock on the open market to cover positions created by short sales. Short sales may be covered shorts, which are short positions in an amount not greater than the underwriters overallotment option referred to above, or may be naked shorts, which are short positions in excess of that amount. The underwriters may close out any covered short position either by exercising their overallotment option, in whole or in part, or by purchasing shares in the open market. In making this determination, the underwriters will consider, among other things, the price of shares available for purchase in the open market compared to the price at which the underwriters may purchase shares through the overallotment option. A naked short position is more likely to be created if the underwriters are concerned that there may be downward pressure on the price of the common stock in the open market that could adversely affect investors who purchase in this offering. To the extent that the underwriters create a naked short position, they will purchase shares in the open market to cover the position.

The underwriters have advised us that, pursuant to Regulation M under the Securities Exchange Act of 1934, they may also engage in other activities that stabilize, maintain or otherwise affect the price of the common stock, including the imposition of penalty bids. This means that if the representatives of the underwriters purchase common stock in the open market in stabilizing transactions or to cover short sales, the representatives can require the underwriters that sold those shares as part of this offering to repay the underwriting discount received by them.

These activities may have the effect of raising or maintaining the market price of the common stock or preventing or retarding a decline in the market price of the common stock, and, as a result, the price of the common stock may be higher than the price that otherwise might exist in the open market. Neither we nor any of the underwriters make any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of our common stock. If the underwriters commence these activities, they may discontinue them at any time. The underwriters may carry out these transactions on the New York Stock Exchange, in the over-the-counter market or otherwise.

Prior to this offering, there has been no public market for our common stock. The initial public offering price will be determined by negotiation by us, the selling shareholder and the representatives of the underwriters. In determining the initial public offering price, we, the selling shareholder and the representatives of the underwriters expect to consider a number of factors including:

the information set forth in this prospectus and otherwise available to the representatives;

our prospects and the history and prospects for the industry in which we compete;

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- an assessment of our management;
- our prospects for future earnings;
- the general condition of the securities markets at the time of this offering; and
- the recent market prices of, and demand for, publicly traded common stock of generally comparable companies.

None of the underwriters, our company or the selling shareholder can assure investors that an active trading market will develop for our shares of common stock, or that the shares will trade in the public market at or above the initial public offering price.

Certain of the underwriters and their affiliates have provided in the past to us and our affiliates and may provide from time to time in the future certain commercial banking, financial advisory, investment banking and other services for us and such affiliates in the ordinary course of their business, for which they have received and may continue to receive customary fees and commissions. In addition, from time to time, certain of the underwriters and their affiliates may effect transactions for their own account or the account of customers, and hold on behalf of themselves or their customers, long or short positions in our debt or equity securities or loans, and may do so in the future.

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Legal Matters

The validity of the shares of common stock offered by this prospectus will be passed upon for us by Crowe & Dunlevy, A Professional Corporation, Oklahoma City, Oklahoma. Certain other legal matters will be passed upon for us by Vinson & Elkins L.L.P., Houston, Texas. Certain legal matters with respect to the offering will be passed upon for the underwriters by Davis Polk & Wardwell, New York, New York. Vinson & Elkins L.L.P. and Davis Polk & Wardwell will rely upon Crowe & Dunlevy, A Professional Corporation as to all matters of Oklahoma law.

Experts

The consolidated financial statements of Continental Resources, Inc. and subsidiary as of December 31, 2005 and 2006 and for each of the three years in the period ended December 31, 2006, included in this prospectus and elsewhere in the registration statement have been audited by Grant Thornton LLP, independent registered public accountants, as indicated in their reports with respect thereto, and are included herein in reliance upon the authority of said firm as experts in accounting and auditing.

Estimates of the oil and gas reserves of Continental Resources, Inc. and related future net cash flows and the present values thereof as of December 31, 2004, 2005 and 2006 included herein were based in part upon reserve reports prepared by Ryder Scott Company, L.P., independent petroleum engineers. We have incorporated these estimates in reliance on the authority of such firm as an expert in such matters.

Where You Can Find More Information

We have filed with the SEC under the Securities Act a registration statement on Form S-1 with respect to the common stock offered by this prospectus. This prospectus, which constitutes part of the registration statement, does not contain all the information set forth in the registration statement or the exhibits and schedules which are part of the registration statement, portions of which are omitted as permitted by the rules and regulations of the SEC. Statements made in this prospectus regarding the contents of any contract or other document are summaries of the material terms of the contract or document. With respect to each contract or document filed as an exhibit to the registration statement, reference is made to the corresponding exhibit. For further information pertaining to us and the common stock offered by this prospectus, reference is made to the registration statement, including the exhibits and schedules thereto, copies of which may be inspected without charge at the public reference facilities of the SEC at 100 F. Street, N.E., Washington, D.C. 20549. Copies of all or any portion of the registration statement may be obtained from the SEC at prescribed rates. Information on the public reference facilities may be obtained by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains a web site that contains reports, proxy and information statements and other information that is filed through the SEC s EDGAR System. The web site can be accessed at http://www.sec.gov.

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Report of Independent Registered Public Accounting Firm

Board of Directors

Continental Resources, Inc.

We have audited the accompanying consolidated balance sheets of Continental Resources, Inc. and Subsidiary as of December 31, 2005 and 2006, and the related consolidated statements of income, shareholders equity and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these 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. The Company is not required to have, nor were we engaged to perform an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 Continental Resources, Inc. and Subsidiary as of December 31, 2005 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma

March 15, 2007

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Continental Resources, Inc. and Subsidiary

Consolidated Balance Sheets

	Historical		Pro forma
	December 31,		December 31,
	2005	2006	2006
			(Unaudited)
	(In thousands, except par values and share data)		
Current assets:			
Cash and cash equivalents	$ 6,014	$ 7,018	$ 7,018
Receivables:			
Oil and gas sales	20,509	55,037	55,037
Affiliated parties	42,112	7,698	7,698
Joint interest and other, net	14,726	26,351	26,351
Inventories	4,826	7,831	7,831
Prepaid expenses	660	1,046	1,046
Total current assets	88,847	104,981	104,981
Net property and equipment, based on successful efforts method of accounting	509,393	751,747	751,747
Debt issuance costs, net	1,994	2,201	2,201
Total assets	$ 600,234	$ 858,929	$ 858,929
Liabilities and shareholders equity			
Current liabilities:			
Accounts payable trade	$ 33,598	$ 100,414	$ 100,414
Accounts payable to affiliated parties	3,121	13,727	13,727
Dividends payable		218	52,318
Accrued liabilities	28,795	34,954	35,172
Revenues and royalties payable	31,655	28,738	28,738
Current portion of asset retirement obligation	2,120	2,528	2,528
Total current liabilities	99,289	180,579	232,897
Long-term debt	143,000	140,000	140,000
Other noncurrent liabilities:			
Asset retirement obligation, net of current portion	32,233	38,745	38,745
Other noncurrent liabilities	982	1,086	1,086
Total other noncurrent liabilities	33,215	39,831	39,831
Commitments and contingencies (Notes 7 and 10)			
Shareholders equity:			

Preferred stock, $0.01 par value: 1,000,000 shares authorized; no shares issued and outstanding			
Common stock, $.01 par value; 20,000,000 shares authorized, 14,458,966 shares issued and outstanding at December 31, 2005; 14,464,204 shares issued and outstanding at December 31, 2006	144	144	144
Additional paid-in-capital	27,087	27,087	380,942
Retained earnings	297,461	471,313	65,140
Accumulated other comprehensive income (loss)	38	(25)	(25)
Total shareholders equity	324,730	498,519	446,201
Total liabilities and shareholders equity	$ 600,234	$ 858,929	$ 858,929

See Note 1 relating to pro forma information.

The accompanying notes are an integral part of these consolidated financial statements.

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Continental Resources, Inc. and Subsidiary

Consolidated Statements of Income

	Year ended December 31,		
	2004	2005	2006
	(In thousands, except share data)		
Revenues:			
Oil and natural gas sales	$ 162,419	$ 252,947	$ 374,304
Oil and natural gas sales to affiliates	19,016	108,886	94,298
Crude oil marketing and trading	226,664		
Oil and natural gas service operations	10,811	13,931	15,050
Total revenues	418,910	375,764	483,652
Operating costs and expenses:			
Production expense	36,801	39,709	45,694
Production expense to affiliates	6,953	13,045	17,171
Production tax	12,297	16,031	22,331
Exploration expense	12,633	5,231	19,738
Crude oil marketing and trading	227,210		
Oil and gas service operations	6,466	7,977	8,231
Depreciation, depletion, amortization and accretion	38,627	49,802	65,428
Property impairments	11,747	6,930	11,751
General and administrative	12,400	31,266	23,016
(Gain) loss on sale of assets	150	(3,026)	(290)
Total operating costs and expenses	365,284	166,965	213,070
Income from operations	53,626	208,799	270,582
Other income (expense):			
Interest expense	(23,309)	(11,326)	(11,310)
Interest expense to affiliates	(308)	(2,894)	
Loss on redemption of bonds	(4,083)		
Other	890	867	1,742
	(26,810)	(13,353)	(9,568)
Income from continuing operations before income taxes	26,816	195,446	261,014
Provision (benefit) for income taxes		1,139	(132)
Income from continuing operations	26,816	194,307	261,146
Discontinued operations	1,680		
Loss on sale of discontinued operations	(632)		

Net income	$ 27,864	$ 194,307	$ 261,146
Basic:			
Income from continuing operations per share	$ 1.87	$ 13.52	$ 18.17
Net income per share	1.94	13.52	18.17
Diluted:			
Income from continuing operations per share	1.85	13.42	17.99
Net income per share	1.93	13.42	17.99
Cash dividends per share	1.04	0.14	6.06
Pro forma C-corporation and stock split data: (unaudited)			
Income from continuing operations before income taxes	$ 26,816	$ 195,446	$ 261,014
Pro forma provision for income taxes attributable to continuing operations	10,190	74,269	99,185
Pro forma income from continuing operations	16,626	121,177	161,829
Discontinued operations, net of tax	1,042		
Loss on sale of discontinued operations, net of tax	(392)		
Pro forma net income	$ 17,276	$ 121,177	$ 161,829
Pro forma basic earnings per share	$ 0.11	$ 0.77	$ 1.02
Pro forma diluted earnings per share	0.11	0.76	1.01

See Note 1 relating to pro forma information.

The accompanying notes are an integral part of these consolidated financial statements.

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Continental Resources, Inc. and Subsidiary

Consolidated Statements of Shareholders Equity

	Shares outstanding	Common stock	Additional paid-in capital	Retained earnings	Accumulated other comprehensive income (loss)	Total shareholders equity
	(In thousands, except share data)					
Balance, January 1, 2004	14,368,919	$ 144	$ 25,087	$ 92,190	$ (489)	$ 116,932
Comprehensive income:						
Net income				27,864		27,864
Change in fair value of derivative contracts					(5,907)	(5,907)
Reclassification of loss on settled contracts					6,396	6,396
Net change in fair value of derivative contracts						489
Total comprehensive income						28,353
Cash dividends				(14,900)		(14,900)
Balance, December 31, 2004	14,368,919	144	25,087	105,154		130,385
Comprehensive income:						
Net income				194,307		194,307
Other comprehensive income					38	38
Total comprehensive income						194,345
Issuance of restricted stock	90,047					
Capital contribution			2,000			2,000
Cash dividends				(2,000)		(2,000)
Balance, December 31, 2005	14,458,966	144	27,087	297,461	38	324,730
Comprehensive income:						
Net income				261,146		261,146
Other comprehensive loss					(63)	(63)
Total comprehensive income						261,083
Stock options exercised	2,060					
Issuance of restricted stock	18,252					
Repurchased and cancelled restricted stock	(2,119)					
Restricted stock withheld for taxes	(3,396)					
Forfeited restricted stock	(9,559)					
Cash dividends				(87,294)		(87,294)
Balance, December 31, 2006	14,464,204	$ 144	$ 27,087	$ 471,313	$ (25)	$ 498,519

The accompanying notes are an integral part of these consolidated financial statements.

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Continental Resources, Inc. and Subsidiary

Consolidated Statements of Cash Flows

	Year ended December 31,		
	2004	2005	2006
		(In thousands)	
Cash Flows from operating activities:			
Net income	$ 27,864	$ 194,307	$ 261,146
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	38,987	48,206	63,860
Accretion of asset retirement obligation	1,036	1,596	1,680
Property Impairments	11,747	6,930	11,751
Amortization of debt issuance costs	4,789	1,662	900
(Gain) loss on sale of assets	1,566	(3,026)	(290)
Loss on redemption of bonds	4,083		
Dry hole costs	9,489	1,432	13,344
Equity compensation	2,010	13,715	2,874
Changes in assets and liabilities:			
Accounts receivable	(15,133)	(39,194)	(11,739)
Inventories	(280)	766	(3,005)
Prepaid expenses	(695)	371	(386)
Accounts payable	7,129	12,205	77,422
Revenues and royalties payable	4,372	19,033	(2,917)
Accrued liabilities and other	(2,901)	6,456	2,297
Other noncurrent assets	(221)		
Other noncurrent liabilities	12	806	104
Net cash provided by operating activities	93,854	265,265	417,041
Cash flows from investing activities:			
Exploration and development	(88,361)	(140,591)	(313,071)
Purchase of other property and equipment	(5,190)	(1,942)	(6,944)
Purchase of oil and gas properties	(756)	(2,267)	(6,564)
Proceeds from sale of assets	389	11,084	2,056
Net cash acquired on disposition of subsidiary	20,926		
Net cash used in investing activities	(72,992)	(133,716)	(324,523)
Cash flows from financing activities:			
Line of credit and other borrowings	147,100	25,000	286,000
Repayment of senior subordinated notes	(131,233)		
Repayment of shareholder note		(48,000)	
Repayment of line of credit and other borrowings	(4,562)	(112,464)	(289,000)
Payment of stock-based compensation		(3,915)	
Dividends to shareholders	(14,900)	(2,000)	(87,373)
Debt issuance costs	(3,650)	(88)	(1,107)
Exercise of options			29
Net cash used in financing activities	(7,245)	(141,467)	(91,451)

Effect of exchange rate changes on cash and cash equivalents		38	(63)
Net change in cash and cash equivalents	13,617	(9,880)	1,004
Cash and cash equivalents at beginning of period	2,277	15,894	6,014
Cash and cash equivalents at end of period	$ 15,894	$ 6,014	$ 7,018

The accompanying notes are an integral part of these consolidated financial statements.

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements

1. Organization and Summary of Significant Accounting Policies

Description of Company

Continental Resources, Inc. (Continental or the Company) was incorporated in Oklahoma on November 16, 1967, as Shelly Dean Oil Company. On September 23, 1976, the name was changed to Hamm Production Company. In January 1987, the Company acquired all of the assets and assumed the debt of Continental Trend Resources, Inc. and affiliated entities J.S. Aviation and Wheatland Oil Co., which were merged into Hamm Production Company, and the corporate name was changed to Continental Trend Resources, Inc. In 1991, the Company s name was changed to Continental Resources, Inc. Effective June 1, 1997, the Company converted to an S-corporation under subchapter S of the Internal Revenue Code.

On July 21, 2004, the Company completed the sale of all of the outstanding stock of its subsidiary Continental Gas, Inc. (CGI) to the Company s shareholders, for $22.6 million in cash. The sales price was representative of the fair value of the net assets based on an appraisal by an independent third party who also provided the Company with an opinion of the fairness from a financial point of view of the sale of CGI to the shareholders. The CGI assets included seven gas gathering systems and three gas-processing plants. The results of operations of CGI prior to its disposition are included in income from discontinued operations for the year ended December 31, 2004 and represent revenues of $51.0 million and income from discontinued operations of $1.7 million.

Continental had one wholly owned subsidiary, Continental Resources of Illinois, Inc. (CRII) at December 31, 2004 and 2005. CRII was incorporated in June 2001 for the purpose of acquiring the assets of Farrar Oil Company and Har-Ken Oil Company. Continental acquired Banner Pipeline Company, L.L.C. (Banner) on March 30, 2006 for approximately $8.8 million, which represented the book value of working capital, principally cash, accounts receivable, crude oil inventory and accounts payable. CRII was merged into Continental on October 12, 2006. Banner was Continental s only subsidiary at December 31, 2006.

Continental s principal business is oil and natural gas exploration, development and production. As of December 31, 2006, the Company had interests in approximately 1,589 wells and serves as the operator of 1,302 of these wells. The Company s operations are primarily in the Rocky Mountain, the Mid-Continent and the Gulf Coast regions of the United States.

Basis of presentation

All significant inter-company accounts and transactions have been eliminated in the consolidated financial statements.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Of the estimates and assumptions that affect reported results, the estimate of the Company s oil and natural gas reserves, which is used to compute depreciation, depletion, amortization and impairment on producing oil and gas properties, is the most significant.

Revenue recognition

Oil and natural gas sales result from undivided interests held by the Company in oil and natural gas properties. Sales of oil and natural gas produced from oil and natural gas operations are recognized when the

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

product is delivered to the purchaser and title transfers to the purchaser. The Company uses the sales method of accounting for natural gas imbalances in those circumstances where it has under-produced or over-produced its ownership percentage in a property. Under this method, a receivable or liability is recognized only to the extent that an imbalance cannot be recouped from the reserves in the underlying properties. The Company s aggregate imbalance positions at December 31, 2005 and 2006 were not material. Charges for gathering and transportation are included in production expenses.

During 2004 and the first three months of 2005, the Company purchased barrels of oil back from certain of its wellhead purchasers downstream of the initial sales point to exchange at the Cushing, Oklahoma hub in order to minimize pricing differentials with the NYMEX oil futures contract. In 2005, revenues of $39.8 million and expenses of $39.7 million pertaining to these marketing activities were netted as provided by Emerging Issues Task Force (EITF) 04-13, which the Company adopted as of January 2005. The Company presented this purchase and sale activity gross in the 2004 income statement as crude oil marketing and trading revenues of $226.7 million and crude oil marketing and trading expenses of $227.2 million under the guidance provided by EITF 99-19, Reporting Revenues Gross as a Principal and/or Net as an Agent. The Company ceased marketing its production in this manner in March 2005 and now generally markets its production at the wellhead.

Cash and cash equivalents

The Company considers all highly liquid investments with original maturities of three months or less to be cash equivalents. The Company maintains its cash and cash equivalents in accounts that may not be federally insured. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk.

At December 31, 2005 and 2006, the Company s cash included approximately $301,000 and $216,000, respectively, in a Canadian bank, which was converted to US dollars using the exchange rates in effect at December 31, 2005 and 2006.

Accounts receivable

The Company operates exclusively in oil and natural gas exploration and production related activities. Oil and natural gas sales and joint interest receivables are generally unsecured. Accounts receivable are due within 30 days and considered delinquent after 60 days. The Company determines its allowance for doubtful accounts by considering a number of factors, including the length of time accounts are past due, the Company s loss history, and the customer or working interest owner s ability to pay. The Company writes off specific accounts when they become uncollectible and any payments subsequently received on these receivables are credited to the allowance for doubtful accounts. The following table presents the allowance for doubtful accounts at December 31, 2004, 2005 and 2006 and changes in the allowance for these years:

	Balance at beginning of period	Additions charged to costs and expenses	Deductions	Balance at end of period
Year ended December 31, 2004	$ 229,972	$ 23,000	$	$ 252,972
Year ended December 31, 2005	252,972	59,378	(140,899)	171,451
Year ended December 31, 2006	171,451	68,178	(46,303)	193,326

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

Concentration of credit risk

The Company is subject to credit risk resulting from the concentration of its crude oil and natural gas receivables with several significant customers. The largest purchasers of the Company s oil and gas production accounted for 56% (three purchasers), 60% (three purchasers) and 33% (two purchasers) of total oil and natural gas sales revenues for 2004, 2005 and 2006 respectively. These purchasers constituted all purchasers with oil and natural gas sales in excess of 10% of total oil and natural gas sales. The Company does not require collateral. While the Company believes its recorded receivables will be collected, in the event of default the Company would follow normal collection procedures. The Company does not believe the loss of any single purchaser would materially impact its operating results, as oil and natural gas are fungible products with well-established markets and numerous purchasers.

Debt issuance costs

Costs incurred in connection with the issuance of long-term debt are capitalized and amortized over the term of the related debt. The Company had capitalized costs of $2.0 million and $2.2 million (net of accumulated amortization of $3.8 million and $4.5 million) relating to the issuance of its long-term debt at December 31, 2005 and 2006, respectively. During the years ended December 31, 2004, 2005 and 2006, the Company recognized associated amortization expense of $4.8 million, $1.7 million and $0.9 million, respectively.

Inventories

Inventories are stated at the lower of cost or market. Inventory consists primarily of tubular goods and production equipment, which totaled approximately $4.8 million and $4.2 million at December 31, 2005 and 2006, respectively, and crude oil line fill of approximately $3.6 million at December 31, 2006. The Company had no crude oil in inventory at December 31, 2005.

Property and equipment

Property and equipment are capitalized and stated at cost, while maintenance and repairs are expensed as incurred.

Depreciation and amortization are provided in amounts sufficient to expense the cost of depreciable assets to operations over their estimated useful lives using the straight-line method. Estimated useful lives are as follows:

Property and Equipment	**Useful Lives in Years**
Furniture and fixtures	10
Automobiles	5
Machinery and equipment	10-20
Office and computer equipment	5
Building and improvements	10-40

Oil and gas properties

The Company uses the successful efforts method of accounting for oil and gas properties whereby costs to acquire mineral interests in oil and gas properties, drill and equip exploratory wells that find proved reserves and to drill and equip development wells are capitalized. Geological and geophysical costs, seismic costs, lease

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

rentals and costs associated with unsuccessful exploratory wells are expensed as incurred. Maintenance and repairs are expensed as incurred, except that the cost of replacements or renewals that expand capacity or improve production are capitalized.

The Company reports capitalized exploratory drilling costs on the balance sheet according to Statement of Financial Accounting Standards (SFAS) No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies (SFAS No. 19). On a monthly basis, the Company capitalizes the costs of drilling exploratory wells pending determination of whether the well has found proved reserves. The Company capitalizes costs associated with the acquisition or construction of support equipment and facilities with the drilling and development costs to which they relate. If proved reserves are found by an exploratory well, associated capitalized costs become part of well equipment and facilities; however, if proved reserves are not found, the capitalized costs associated with the well are expensed, net of any salvage value. Total capitalized exploratory drilling costs, as of December 31, 2005 and 2006, pending the determination of proved reserves were $1.9 million and $10.0 million, respectively. None of these costs were suspended beyond one year.

Production expenses are those costs incurred by the Company to operate and maintain its oil and natural gas properties and associated equipment and facilities. Production expenses include labor costs to operate the Company s properties, repairs and maintenance, and materials and supplies utilized in the Company s operations.

The Company accounts for its asset retirement obligations pursuant to SFAS No. 143, Accounting for Asset Retirement Obligations which requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement costs are charged to expense using a systematic and rational method and the liability is accreted to the expected abandonment amount over the asset s life.

The Company s primary asset retirement obligations relate to future plugging and abandonment expenses on its oil and natural gas properties and related facilities disposal. The following table summarizes the changes in the Company s future abandonment liability from January 1, 2005 through December 31, 2006 (in thousands):

	2004	2005	2006
Asset retirement obligation liability at January 1,	$ 26,608	$ 34,192	$ 34,353
Asset retirement obligation accretion expense	1,036	1,596	1,680
Plus: Revisions	6,726		4,391
Additions for new assets	516	1,031	2,480
Less: Plugging costs and sold assets	(694)	(2,466)	(1,631)
Asset retirement obligation liability at December 31,	$ 34,192	$ 34,353	$ 41,273

As of December 31, 2005 and 2006, property and equipment included $21.9 million and $27.7 million, respectively, of net asset retirement costs. The Company considered the impact of FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations and determined that it did not have a material effect on the Company s results of operations or financial condition.

Depreciation, depletion, amortization, accretion and impairment

Depreciation, depletion, and amortization (DD&A) of capitalized drilling and development costs, including related support equipment and facilities, of producing oil and gas properties are computed using the units of

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

production method on an individual property, field or unit basis based on total estimated proved developed oil and gas reserves. Amortization of producing leasehold is based on the unit-of-production method using total estimated proved reserves. In arriving at rates under the unit-of-production method, the quantities of recoverable oil and natural gas are established based on estimates made by the Company s geologists, engineers and independent reserve engineers. Upon sale or retirement of properties, the cost and related accumulated DD&A are eliminated from the accounts and the resulting gain or loss is recognized. Unit of production rates are revised whenever there is an indication of a need, but at least twice annually in conjunction with its semi-annual reserve reports. Revisions are accounted for prospectively as changes in accounting estimates.

Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of proved undeveloped reserves. Individually significant non-producing properties are periodically assessed for impairment of value and a loss is recognized at the time of impairment by providing an impairment allowance. Other non-producing properties are amortized on a composite method based on the Company s estimated experience of successful drilling and the average holding period. Impairment of non-producing properties was $5.5 million, $4.4 million and $5.4 million for 2004, 2005, and 2006 respectively.

In accordance with the provisions of SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets , the Company recognizes impairment expenses for developed oil and gas properties and other long-lived assets when indicators of impairment are present and the undiscounted cash flows from proved and risk-adjusted probable reserves are not sufficient to recover the assets carrying amount. The impairment loss is measured by comparing the fair value of the asset to its carrying amount. Fair values are based on discounted future cash flows. The Company s oil and gas properties are reviewed for indicators of impairment on a field-by-field basis, resulting in the recognition of impairment provisions of $6.2 million, $2.5 million and $6.3 million, respectively, for 2004, 2005 and 2006. The majority of the impairment recognized in these years relates to fields comprised of a small number of properties or single wells on which the Company does not expect sufficient future net cash flows to recover its carrying cost.

The costs of retired, sold, or abandoned properties that constitute part of an amortization base are charged or credited, net of proceeds received, to the accumulated depletion, depreciation and amortization reserve. Gains or losses from the disposal of other properties are recognized in the current period. Effective July 1, 2005, the Company adopted SFAS No. 153, Exchanges of Nonmonetary Assets, an Amendment of APB Opinion No. 29 (SFAS No. 153), for the exchanges of nonmonetary assets occurring after the implementation date. Prior to implementing SFAS No. 153, the Company generally did not recognize gains on nonmonetary exchanges involving oil and gas properties. According to the provisions of SFAS No. 153, all nonmonetary asset exchanges that have commercial substance, as defined, will be measured at fair value with gain or loss recognized in earnings. Values of historical nonmonetary asset exchanges have not been material.

Income taxes

Effective June 1, 1997, the Company converted to an S-corporation under Subchapter S of the Internal Revenue Code. As a result, income taxes attributable to federal and state taxable income of the Company after May 31, 1997, if any, are payable by the shareholders of the Company. Certain properties held by the Company at the time of the conversion may be subject to federal taxation on the excess of the S-corporation conversion date fair market value over the asset s then taxable basis if sold within 10 years of the conversion to an S-corporation. These taxes are payable by the Company. In 2005, the Company recorded federal income tax expense of $1.1 million attributable to such gains on sales of properties according to section 1374 of the Internal Revenue Code. The benefit recorded during 2006 reflects a change in estimate of the original provision recorded.

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

Pro forma information (unaudited)

Pro forma adjustments are reflected on the 2006 consolidated balance sheet to adjust for $52.1 million of dividends declared after December 31, 2006 and the reclassification of undistributed earnings between retained earnings and additional paid-in capital in connection with the Company s conversion from an S-corporation to a C-corporation in connection with its planned initial public offering as if the conversion had occurred on December 31, 2006.

Pro forma adjustments are reflected on the consolidated statements of income to provide for income taxes in accordance with SFAS No. 109 as if the Company had been a C-corporation for all periods presented. For unaudited pro forma income tax calculations, deferred tax assets and liabilities were recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities were measured using enacted tax rates expected to apply to taxable income in the years in which the Company expects to recover or settle those temporary differences. A statutory Federal tax rate of 35% and effective state tax rate of 3% (net of Federal income tax effects) were used for the pro forma enacted tax rate for all periods. The pro forma tax effects are based upon currently available information. Management believes that these assumptions provide a reasonable basis for representing the pro forma tax effects.

Pro forma adjustments are reflected on the consolidated statements of income to adjust earnings per share for the effect of the Company s planned 11 for 1 stock split to be effected as a stock dividend in connection with the consummation of the Company s planned initial public offering.

Issued and outstanding shares, inclusive of restricted stock, at December 31, 2005 and 2006 on a historical and pro forma basis, were as follows:

	December 31,	
	2005	2006
Outstanding shares (historical)	14,458,966	14,464,204
Outstanding shares (pro forma)	159,048,626	159,106,244

The following table sets forth the computation of shares used in the pro forma basic and diluted earnings per share computations for the years ended December 31, 2004, 2005 and 2006:

	Year ended December 31,		
	2004 Shares	2005 Shares	2006 Shares
Shares used in basic earnings per share	158,058,109	158,058,109	158,115,089
Effect of dilutive securities:			
Restricted stock		160,094	299,508
Employee stock options	1,180,817	1,087,812	1,247,939
Shares used in diluted earnings per share	159,238,926	159,306,015	159,662,536

The pro forma information should be read in conjunction with the related historical information and is not necessarily indicative of the results that would have been attained had the transactions actually taken place.

Comprehensive income

The Company classifies other comprehensive income (loss) items by their nature in the consolidated financial statements and displays the accumulated balance of other comprehensive income (loss) separately in the

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

shareholders equity section of the balance sheet. Accumulated other comprehensive income (loss) at December 31, 2005 and 2006 consists of foreign currency translation.

Earnings per common share

Basic earnings per common share is computed by dividing net income by the weighted-average number of shares outstanding for the period. Diluted earnings per share reflects the potential dilution of nonvested restricted stock awards and dilutive stock options, which are calculated using the treasury stock method as if these options were exercised. The following tables set forth earnings per share and the computation of shares used in the basic and diluted earning per share computations for the years ended December 31, 2004, 2005 and 2006:

	Year ended December 31,		
	2004	**2005**	**2006**
Basic income per share:			
From continuing operations	$ 1.87	$ 13.52	$ 18.17
From discontinued operations	0.11		
Loss on sale of discontinued operations	(0.04)		
Net income per share	$ 1.94	$ 13.52	$ 18.17
Diluted income per share:			
From continuing operations	$ 1.85	$ 13.42	$ 17.99
From discontinued operations	0.12		
Loss on sale of discontinued operations	(0.04)		
Net income per share	$ 1.93	$ 13.42	$ 17.99

	Year ended December 31,		
	2004 Shares	**2005 Shares**	**2006 Shares**
Shares used in basic earnings per share	14,368,919	14,368,919	14,374,099
Effect of dilutive securities:			

Restricted stock		14,554	27,228
Employee stock options	107,347	98,892	113,449
Shares used in diluted earnings per share	14,476,266	14,482,365	14,514,776

Accounting for derivatives

The Company had no open hedges at December 31, 2005 or 2006. In 2004, the Company utilized derivative contracts to hedge the commodity price risk associated with specifically identified purchase or sales contracts, oil and gas production or operational needs. The Company accounted for its non-trading derivative activities under the guidance provided by SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities , as amended, and recognized all of its derivative instruments as assets or liabilities in the balance sheet at fair value with such amounts classified as current or long-term based on their anticipated settlement. The accounting for the changes in fair value of a derivative depends on the intended use of the derivative and resulting designation.

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Notes to Consolidated Financial Statements (continued)

Fair value of financial instruments

The Company s financial instruments consist primarily of cash, trade receivables, trade payables and long-term debt. The carrying value of cash, trade receivables and trade payables are considered to be representative of their respective fair values, due to the short maturity of these instruments.

The fair value of long-term debt approximates its carrying value based on the borrowing rates currently available to the Company for bank loans with similar terms and maturities. The estimated fair value of long-term debt is $143.0 million and $140.0 million at December 31, 2005 and 2006, respectively.

Equity compensation

The Company accounts for employee stock option grants and restricted stock grants in accordance with SFAS 123(R). The terms of the restricted stock grants and stock option grants stipulate that, while the Company is a private company, it is required to purchase the vested restricted stock and stock acquired from stock option exercises at each employee s request based upon the purchase price as determined by a formula specified in each award agreement. Additionally, the Company has the right to purchase vested restricted stock and stock acquired from stock option exercises at the same price upon termination of employment for any reason and for a period of two years subsequent to leaving the employment of the Company. The Company measures compensation cost for the awards based upon the formula purchase price which is determined by calculating a per share value for shareholders equity adjusted for the excess of each period s ending PV-10 oil and gas reserve valuation over the book value of oil and gas properties.

The right to sell and requirement to purchase will lapse when the Company becomes a reporting company under Section 12 of the Exchange Act. Upon becoming a reporting company under Section 12 of the Exchange Act, the Company will be required to record a charge to earnings to adjust the plan determined share price to the price received in an initial public offering and account for the grants under the fair value provisions of SFAS 123(R) thereafter.

Recent accounting pronouncements

In December 16, 2004, the FASB issued SFAS 123(R), Share-Based Payment, a revision of SFAS 123, and APB Opinion 25, Accounting for Stock Issued to Employees . SFAS 123(R) requires that the fair value of share-based payment transactions (including those with employees and non-employees) be recognized in the financial statements. SFAS 123(R) applies to all share-based payment transactions in which an entity acquires goods or services by issuing (or offering to issue) its shares, share options or other equity instruments (except for those held by an

ESOP) or by incurring liabilities (1) in amounts based on the price of the entity s shares or other equity instruments or (2) that require (or may require) settlement by the issuance of an entity s share or other equity instruments. SFAS 123(R) is effective for the Company in the first annual reporting period after December 15, 2005. The Company implemented SFAS 123(R) on January 1, 2006 using the modified prospective application. The adoption of SFAS 123(R) did not have a material effect on the Company s consolidated financial statements.

In September 2006, the Securities and Exchange Commission issued Staff Accounting Bulletin (SAB) No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Current Year Misstatements*. SAB No. 108 requires analysis of misstatements using both an income statement (rollover) approach and a

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balance sheet (iron curtain) approach in assessing materiality and provides for a one-time cumulative effect transition adjustment. The Company has applied the guidance of SAB No. 108 effective December 31, 2006. The application of this SAB had no effect on the consolidated financial statements.

In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). The interpretation clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes*. The interpretation is effective for fiscal years beginning after December 15, 2006. The adoption of FIN 48 is not expected to have a material impact on the Company s consolidated financial position or results of operations.

In September 2006, the FASB finalized SFAS No. 157, Fair Value Measurements which will become effective in 2008. This Statement defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements; however, it does not require any new fair value measurements. The provisions of SFAS No. 157 will be applied prospectively to fair value measurements and disclosures in the Company s Consolidated Financial Statements beginning in the first quarter of 2008. The adoption of SFAS No. 157 is not expected to have a material impact on the Company s consolidated financial position or results of operations.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115 . This Statement provides entities with an option to choose to measure eligible items at fair value at specified election dates. If elected, an entity must report unrealized gains and losses on the item in earnings at each subsequent reporting date. The fair value option may be applied instrument by instrument, with a few exceptions, such as investments otherwise accounted for by the equity method; is irrevocable (unless a new election date occurs); and is applied only to entire instruments and not to portions of instruments. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. Management does not believe that the implementation of SFAS No. 159 will have a material impact on the Company s financial statements.

2. Hedging Contracts

The Company has utilized fixed-price contracts and zero-cost collars in the past to reduce exposure to unfavorable changes in oil and gas prices that are subject to significant and often volatile fluctuation. Under the fixed price delivery contracts the Company received the fixed price stated in the contract. Under the zero-cost collars, if the market price of crude oil exceeded the ceiling strike price or fell below the floor strike price, then the Company received the applicable collar strike price. If the market price was between the floor strike price and the ceiling strike price, the Company received market price.

The Company was not a party to any open hedge contracts at December 31, 2005 or 2006. Charges in the amount of $6.4 million for hedging activities are reported as a reduction in oil and gas sales in the income statement for the year ended December 31, 2004. The Company was not a party to any hedging activities during 2005 or 2006. The Company recognized no significant amounts due to hedge ineffectiveness in 2004.

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3. Long-term Debt

The Company had the following long-term debt outstanding as of the dates shown (in thousands):

	December 31,	
	2005	2006
Credit Agreement due April 12, 2011	$ 143,000	$ 140,000

On November 22, 2004, the Company executed a Fifth Amended and Restated Credit Agreement (Credit Agreement, as amended) in which a group of lenders agreed to provide a $400.0 million senior secured revolving credit facility with a commitment of $250.0 million as of December 31, 2005. Borrowings under the credit facility are secured by liens on substantially all oil and gas properties and associated assets of the Company.

On March 23, 2005, the Company executed an amendment to the Credit Agreement and revised the pricing grid, which lowered the Utilization Percentage and the LIBOR margins. On December 7, 2005, the Company executed an amendment to the Credit Agreement in order to terminate certain covenants including a requirement to hedge certain quantities of its production under various conditions.

At that time, borrowings under the credit facility bore interest, payable quarterly, at a rate per annum equal to the London Interbank Offered Rate (LIBOR) for one, two, three or six months, as elected by the Company, plus a margin ranging from 125 to 200 basis points, or at the lead banks reference rate plus an applicable margin ranging from 25 to 50 basis points.

On April 12, 2006, the Company amended the Credit Agreement. The amended facility matures on April 12, 2011. At the Company s election, the maturity date can be extended for up to two one-year periods. Borrowings under the facility bear interest, payable quarterly, at a rate per annum equal to the London Interbank Offered Rate for one, two, three or six months, as elected by the Company, plus a margin ranging from 100 to 175 basis points, depending on the percentage of its borrowing base utilized, or the lead banks reference rate. The amended facility has a note amount of $750.0 million, a borrowing base of $500.0 million, subject to semi-annual redetermination, and a commitment level of $300.0 million. Under the terms of the amended facility, the Company is allowed to set the commitment level at any level up to the borrowing base.

The amended facility contains certain covenants including that the Company maintain a current ratio of not less than 1.0 to 1.0 (inclusive of availability under the Credit Agreement) and a Total Funded Debt to EBITDAX, as defined, of no greater than 3.75 to 1.0. The Company was in compliance with these covenants at December 31, 2006.

The Company had $160.0 million available under the Credit Agreement at December 31, 2006 and incurred approximately $200,000 in commitment fees during 2006. These fees are 0.2% of the daily average excess of the commitment amount over the outstanding credit balance. Fees are payable five business days after the end of each quarter. The Company paid approximately $1.1 million in debt issuance fees for the new credit facility, which was capitalized and is being amortized on a straight-line basis, the use of which approximates the effective interest method, over the life of the credit facility. The Company s weighted average interest rate was 6.42% at December 31, 2006.

The Company redeemed $119.5 million of Senior Subordinated 10.25% Notes during November 2004 and paid a premium of $4.1 million due to early redemption of the notes.

On November 22, 2004, the Company signed a note with its principal shareholder for $50.0 million. The annual rate of interest was 6.00% and interest payments were due the last day of each calendar quarter beginning

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December 31, 2004. The maturity date of the note was March 31, 2008. A subordination agreement was executed making the $50.0 million note to the Company subordinate to the Credit Agreement discussed above. The Company paid the outstanding balance in December 2005. (Note 11)

At December 31, 2006, the Company had $2.0 million of outstanding letters of credit that expire during 2007.

4. Cash Flow Information

Net cash provided by operating activities reflects cash payments as follows (in thousands):

	December 31,		
	2004	2005	2006
Interest paid	$ 29,313	$ 14,598	$ 10,875
Income taxes paid			1,007

Noncash investing and financing activities are as follows (in thousands):

	December 31,		
	2004	2005	2006
Capital contribution note payable forgiven by shareholder	$	$ 2,000	$
Cancellation of capital leases		10,058	
Asset retirement obligations	7,242	1,031	6,871

5. Property, Plant, and Equipment

Property, plant and equipment includes the following at December 31, 2005 and 2006 (in thousands):

	2005	2006
Proved oil and gas properties	$ 753,841	$ 1,032,108
Unproved oil and gas properties	32,785	57,309
Service properties, equipment and other	19,790	25,668
Total property and equipment	806,416	1,115,085
Accumulated depreciation, depletion and amortization	(297,023)	(363,338)
Net property and equipment	$ 509,393	$ 751,747

6. Accrued Liabilities

Accrued liabilities includes the following at December 31, 2005 and 2006 (in thousands):

	2005	2006
Equity compensation	$ 12,186	$ 14,444
Production taxes and income taxes	9,417	7,369
Drilling cost advances from third parties	2,295	7,235
Interest	652	989
Other	4,245	5,135
Total accrued liabilities	$ 28,795	$ 35,172

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7. Lease Commitments

The Company leases office space under operating leases from the principal shareholder (See Note 11).

The Company had a capital lease arrangement to lease compressors in place at December 31, 2004 from a related party. The assets related to these capital leases totaled $16.8 million at December 31, 2004, with accumulated depreciation of $3.5 million at December 31, 2004. In 2005, the capital lease contract was cancelled and the Company executed an operating lease effective January 28, 2005. The Company recorded a loss of $3.1 million on the termination of the capital lease. The Company pays approximately $400,000 per month under the operating lease. The term of the operating lease is through January 28, 2009.

Lease expense associated with the Company s operating leases for the years ended December 31, 2004, 2005 and 2006, was $0.7 million, $5.3 million and $5.9 million, respectively. At December 31, 2006, including leases renewed and entered into subsequent to December 31, 2006, the minimum future rental commitments under operating leases having non-cancelable lease terms in excess of one year, including leases from related parties, are as follows (in thousands):

Year	Leases with Related Parties	Leases with Non-Related Parties	Total Amount
2007	$ 4,936	$ 360	$ 5,296
2008	4,819	313	5,132
2009	402	141	543
2010		79	79
2011		17	17
Total obligations	$ 10,157	$ 910	$ 11,067

8. Shareholders Equity

On December 8, 2004, the Company s Amended and Restated Certificate of Incorporation was amended to convert 1,000,000 shares of common stock to voting common stock, par value $.01 per share, and 19,000,000 shares of common stock to non-voting common stock, par value $.01 per share. Each share of common stock, par value $.01 per share, outstanding was converted and reclassified into 5% voting common stock and 95% non-voting stock. At December 31, 2005 and 2006, there were 718,446 voting shares and 13,740,520 and 13,745,758 of non-voting shares, respectively.

During 2006, the Company declared cash dividends totaling $87.6 million to existing shareholders and, subject to forfeiture, to holders of unvested restricted stock. Of this amount, $298,000 was charged to compensation expense related to the restricted stock liability. During 2006, the Company paid cash dividends of $87.4 million. The unpaid balance of $218,000 relates to dividends associated with unvested restricted stock and will be paid as the restricted stock vests.

9. Stock Compensation

Effective October 1, 2000, the Company adopted the Continental Resources, Inc. 2000 Stock Option Plan (2000 Plan) and granted options to eligible employees. These options were either Incentive Stock Options, Nonqualified Stock Options or a combination of both. The granted stock options vest either over a five-year period at the rate of 20% each year or over a three year period at the rate of 33 $^{1}/_{3}$% both commencing on the first

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anniversary of the grant date. The maximum number of shares covered consisted of 1,020,000 shares of the Company s common stock, par value $.01 per share. On November 10, 2005, the 2000 Plan was terminated and 152,000 shares of common stock, par value $0.01 per share, remained reserved for unexercised stock options previously granted under the 2000 Plan. As of December 31, 2006, options covering 67,060 shares had been exercised.

The Company s stock option grants under the 2000 plan are as follows:

	Outstanding		Exercisable	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Outstanding December 31, 2003	172,000	$ 10.79	114,933	$ 10.34
Granted	20,000	43.62		
Exercised	(25,000)	12.60		
Canceled				
Outstanding December 31, 2004	167,000	14.45	118,866	10.39
Granted	25,000	62.82		
Exercised	(40,000)	10.50		
Canceled				
Outstanding December 31, 2005	152,000	23.44	109,667	12.59
Granted				
Exercised	(2,060)	13.82		
Canceled	(6,667)	43.62		
Outstanding December 31, 2006	143,273	$ 22.64	124,606	$ 17.51

The total intrinsic value of options exercised during the years ended December 31, 2004, 2005 and 2006 was $0.7 million, $3.2 million and $0.1 million, respectively. The intrinsic value of a stock option is the amount by which the formula derived value of the underlying stock exceeds the exercise price of the option. At December 31, 2006, the outstanding options had a weighted average life of 5.22 years and an aggregate intrinsic value of $6.2 million. At December 31, 2006, the exercisable options had a weighted average life of 4.80 years and an aggregate intrinsic value of $6.1 million. As of December 31, 2006, there was $148,000 of unrecognized compensation expense related to non-vested stock options. The expense is expected to be recognized over a weighted average period of 0.9 years.

The recorded liability associated with the exercise of options during 2004 and 2005 was settled in cash. Shares of common stock were issued in 2006 and the Company s outstanding common stock changed as a result of the options exercised.

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The following table summarizes information about stock options outstanding at December 31, 2006:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	**Number Outstanding**	**Weighted Average Remaining Contractual Life**	**Weighted Average Exercise Price**	**Number Exercisable**	**Weighted-Average Exercise Price**
$7.00 - $7.77	56,940	4.53 years	$ 7.38	54,940	$ 7.36
$14.00	48,000	3.75 years	14.00	48,000	14.00
$43.62	13,333	7.58 years	43.62	13,333	43.62
$62.82	25,000	8.33 years	62.82	8,333	62.82
	143,273		$ 22.64	124,606	$ 17.51

On October 3, 2005, the Company adopted the Continental Resources, Inc. 2005 Long-Term Incentive Plan (2005 Plan) and reserved a maximum of 500,000 shares of non-voting common stock that may be issued pursuant to the 2005 Plan. As of December 31, 2006, the Company had outstanding 71,037 shares of restricted stock granted to directors, officers and key employees under the 2005 Plan. All grants were made on or after October 3, 2005. Restricted stock is awarded in the name of the recipient and except for the right of disposal, constitutes issued and outstanding shares of the Company s common stock for all corporate purposes during the period of restriction including the right to receive dividends, subject to forfeiture. Restricted stock grants vest over periods ranging from one to three years.

Pursuant to the award agreements the Company has the right to purchase vested restricted shares and shares acquired by option exercise at all times the employee remains in the employment of the Company and for a period of two years subsequent to leaving the employment of the Company and grantees have the right to require the Company to purchase vested restricted shares and shares acquired by option exercise, each at a purchase price as determined by a formula specified in each award agreement. All grants of stock options and restricted stock were issued at the then estimated formula purchase price of the Company s stock determined according to the plans. In accordance with the plans, the Company calculates the formula purchase price quarterly based on shareholders equity adjusted for the excess of period end PV-10 oil and gas reserve valuation over the book value of oil and gas properties. The amounts subject to purchase are reflected on the accompanying consolidated balance sheets as liabilities of $12.2 million and $14.4 million as of December 31, 2005 and 2006, respectively. The Company s associated compensation expense, as included in general and administrative expense, was $2.0 million, $13.7 million and $2.9 million during 2004, 2005 and 2006, respectively.

Effective January 1, 2006, the Company adopted SFAS No. 123(R), using the modified-prospective transition method. As the Company s employee stock options and restricted stock awards have been accounted for as liability awards, and adjusted to the formula price as prescribed by the plan at the end of each reporting period, the adoption did not change the accounting for the awards.

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Restricted Stock

The Company issued 90,047 shares of restricted stock during 2005. During 2005 there were no forfeitures or vesting. A summary of changes in the non-vested restricted shares at December 31, 2006, is presented below:

	Number of Non-vested Shares	Weighted Average Grant-Date Fair Value
Non-vested restricted shares as of December 31, 2005	90,047	$ 147.42
Granted	18,252	126.73
Vested	(27,703)	116.95
Forfeited	(9,559)	147.40
Non-vested restricted shares as of December 31, 2006	71,037	$ 153.99

The formula-based value of the restricted shares that vested during 2006 at their vesting date was $3.2 million. The formula as provided in the 2005 Plan determines the value by calculating a per share value for shareholders equity adjusted for the excess of each period s ending PV-10 oil and gas reserve valuation over the book value of oil and gas properties.

As of December 31, 2006, there was $5.2 million of unrecognized compensation expense related to non-vested restricted shares. The expense is expected to be recognized over a weighted average period of 2.3 years.

10. Commitments and Contingencies

During the three years ended December 31, 2006, the Company maintained a defined contribution retirement plan for its employees and makes discretionary contributions to the plan based on a percentage of eligible employees compensation, excluding bonuses. During 2004, 2005 and 2006, contributions to the plan were 5% of eligible employees compensation, excluding bonuses. Expense for the years ended December 31, 2004, 2005 and 2006, was $431,000, $663,000 and $790,000, respectively.

The Company and other affiliated companies participate in a self-insurance pool (the Pool) covering health and workers compensation claims made by employees up to the first $100,000 and $250,000, respectively, per claim. Any amounts paid above these are reinsured through third-party providers. Allocations between the Company and other affiliated companies are based on estimated costs per employee of the Pool. Beginning with 2007, the Company will be segregated from the affiliates at the same limits described above. The Company accrues for claims that have been incurred but not yet reported based on a review of claims filed versus expected claims based on claims history. At December 31, 2005 and 2006 the accrued liability for health claims was $238,000 and $629,000, respectively.

Property and general liability insurance is maintained through third-party providers with a $250,000 deductible on each policy. In combination with excess liability coverage the Company has insurance up to $35 million in place. The Company had no pending claims at December 31, 2006.

The Company is involved in various legal proceedings in the normal course of business, none of which, in the opinion of management, will have a material adverse effect on the financial position or results of operations of the Company. As of December 31, 2005 and 2006, the Company has provided a reserve of $520,000 and $670,000, respectively, for various matters none of which are believed to be individually significant.

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Due to the nature of the oil and gas business, the Company is exposed to possible environmental risks. The Company is not aware of any material environmental issues or claims.

11. Related Party Transactions

The Company currently markets a portion of its natural gas sales to an affiliate. Previously, the Company marketed a portion of its oil sales to an affiliate. During the years ended December 31, 2004, 2005, and 2006, these sales were approximately $19.0 million, $108.9 million, and $94.3 million. The Company also contracts for field services such as compression and drilling rig services and purchases residue fuel gas and reclaimed oil from certain affiliates. Production expense attributable to these affiliates was $7.0 million, $13.0 million and $17.2 million for the years ended December 31, 2004, 2005 and 2006, respectively. The total amount paid to these companies, a portion of which was billed to other interest owners, was approximately $23.4 million, $38.6 million and $52.9 million during the years ended December 31, 2004, 2005 and 2006, respectively. At December 31, 2005 and 2006, approximately $42.1 million and $7.7 million was due from affiliates and approximately $3.1 million and $13.7 million was due to affiliates, respectively.

Affiliates of the Company, owned by the Company s principal shareholder and in one instance by an officer of the Company, also own working and royalty interests in wells operated by the Company. The Company paid revenues, including royalties, of approximately $1.8 million, $5.6 million, and $7.9 million and billed expenses of $1.4 million, $4.2 million, and $5.2 million during the years ended December 31, 2004, 2005, and 2006 to these affiliates and this officer.

The Company leases office space under operating leases from a company owned by the Company s principal shareholder. Rents paid associated with these leases totaled approximately $506,000, $556,000 and $638,000 for the years ended December 31, 2004, 2005 and 2006, respectively. The term of these leases is through February 2008 at an annual rate of approximately $673,000.

On November 22, 2004, the Company entered into a subordinated note with the principal shareholder, which required the Company to make quarterly interest payments beginning December 31, 2004. Interest paid during 2004 and 2005 was $308,000 and $2.9 million, respectively. During 2005, the principal shareholder forgave $2.0 million of this note and a contribution to paid-in capital was recorded. The outstanding balance of $48.0 million was paid on December 27, 2005. (Note 3).

12. Oil and Gas Property Information

The following table sets forth the Company s results of operations from oil and natural gas producing activities for the years ended December 31, 2004, 2005 and 2006 (in thousands):

	December 31,		
	2004	2005	2006
Oil and gas sales	$ 181,435	$ 361,833	$ 468,602
Production expense and tax	(56,051)	(68,785)	(85,196)
Exploration expense	(12,633)	(5,231)	(19,738)
Accretion of asset retirement obligation	(1,029)	(1,596)	(1,680)
Depreciation, depletion and amortization	(36,193)	(46,829)	(62,130)
Property impairments	(11,747)	(6,930)	(11,751)
Results from oil and gas producing activities	$ 63,782	$ 232,462	$ 288,107

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Notes to Consolidated Financial Statements (continued)

	December 31,		
	2004	2005	2006
Pro forma presentation for income tax (unaudited)			
Results from oil and gas producing activities before pro forma income tax	$ 63,782	$ 232,462	$ 288,107
Pro forma income tax	(24,237)	(88,336)	(109,481)
Results from oil and gas producing activities after pro forma income tax	$ 39,545	$ 144,126	$ 178,626

Costs incurred in oil and gas activities

Costs incurred, both capitalized and expensed, in connection with the Company s oil and gas acquisition, exploration and development activities for the three years ended December 31, 2004, 2005 and 2006 are shown below (in thousands).

	2004	2005	2006
Property acquisition costs:			
Proved	$ 756	$ 2,267	$ 6,564
Unproved	11,700	14,496	29,970
Total property acquisition costs	12,456	16,763	36,534
Exploration costs	30,867	9,289	68,686
Development costs	53,036	117,837	221,286
Total	$ 96,359	$ 143,889	$ 326,506

Exploration costs above include asset retirement costs of $244,000, $305,000 and $214,000 and development costs above include asset retirement costs of $6,998,000, $726,000 and $6,658,000 for the years 2004, 2005 and 2006, respectively.

Aggregate capitalized costs

Aggregate capitalized costs relating to the Company s oil and gas producing activities, and related accumulated depreciation, depletion and amortization, as of December 31, 2005 and 2006 are as follows (in thousands):

	2005	2006
Proved oil and gas properties	$ 753,841	$ 1,032,108
Unproved oil and gas properties	32,785	57,309
Total	786,626	1,089,417
Less-accumulated DD&A	(283,036)	(349,192)
Net capitalized costs	$ 503,590	$ 740,225

Under the successful efforts method of accounting, the costs of drilling an exploratory well are capitalized pending determination of whether proved reserves can be attributed to the discovery. When initial drilling operations are complete, management determines whether the well has discovered oil and gas reserves and, if so, whether those reserves can be classified as proved. Often, the determination of whether proved reserves can be recorded under strict Securities and Exchange Commission (SEC) guidelines cannot be made when drilling is completed. In those situations where management believes that commercial hydrocarbons have not been discovered, the exploratory drilling costs are reflected in the Consolidated Statement of Income as dry hole costs (a component of exploration expense). Where sufficient hydrocarbons have been discovered to justify further

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exploration or appraisal activities, exploratory drilling costs are deferred on the Consolidated Balance Sheet pending the outcome of those activities.

At the end of each quarter, operating and financial management review the status of all deferred exploratory drilling costs in light of ongoing exploration activities in particular, whether the Company is making sufficient progress in its ongoing exploration and appraisal efforts. If management determines that future appraisal drilling or development activities are not likely to occur, any associated exploratory well costs are expensed in that period.

The following table presents the amount of capitalized exploratory drilling costs pending evaluation at December 31 for each of the last three years and changes in those amounts during the years then ended (in thousands):

	2004	2005	2006
Balance, January 1	$ 814	$ 3,237	$ 1,874
Additions to capitalized exploratory well costs pending determination of proved reserves	30,024	8,984	65,721
Reclassification to proved oil and gas properties based on the determination of proved reserves	(18,112)	(8,915)	(44,203)
Capitalized exploratory well costs charged to expense	(9,489)	(1,432)	(13,343)
Balance, December 31	$ 3,237	$ 1,874	$ 10,049
Number of projects	2	13	26

13. Supplemental Oil and Gas Information (Unaudited)

The following table shows estimates of proved reserves prepared by the Company s technical staff and independent external reserve engineers in accordance with SEC definitions. Ryder Scott Company prepared reserve estimates for properties comprising 83% of the Company s standardized measure of discounted future net cash flows as of December 31, 2004, 2005 and 2006. Remaining reserve estimates were prepared by the Company s technical staff. Substantially all reserves stated here are located in the United States of America.

Proved reserves are estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured, and estimates of engineers other than the Company s might differ materially from the estimates set forth herein. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and gas that are ultimately recovered.

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Gas imbalance receivables and liabilities for each of the three years ended December 31, 2004, 2005 and 2006, were not material and have not been included in the reserve estimates.

Proved oil and gas reserves

	Natural Gas (MMcf)	Crude Oil (MBbls)
Proved reserves as of December 31, 2003	67,096	73,000
Revisions of previous estimates	1,257	3,172
Extensions, discoveries and other additions	554	7,918
Production	(8,794)	(3,688)
Sale of minerals in place		
Purchase of minerals in place	507	200
Proved reserves as of December 31, 2004	60,620	80,602
Revisions of previous estimates	1,431	1,653
Extensions, discoveries and other additions	54,823	23,290
Production	(9,006)	(5,708)
Sale of minerals in place		(1,292)
Purchase of minerals in place	250	100
Proved reserves as of December 31, 2005	108,118	98,645
Revisions of previous estimates	(307)	416
Extensions, discoveries and other additions	23,235	6,111
Production	(9,225)	(7,480)
Sale of minerals in place		
Purchase of minerals in place	44	346
Proved reserves as of December 31, 2006	121,865	98,038

The following reserve information sets forth the estimated quantities of proved developed and proved undeveloped oil and natural gas reserves of the Company as of December 31, 2004, 2005 and 2006:

Proved Developed Reserves

	Natural Gas (MMcf)	Crude Oil (MBbls)	Oil Equivalent (MBoe)
December 31, 2004	56,733	65,594	75,050
December 31, 2005	54,257	71,259	80,302
December 31, 2006	70,420	75,336	87,073

Proved Undeveloped Reserves	Natural Gas (MMcf)	Crude Oil (MBbls)	Oil Equivalent (MBoe)
December 31, 2004	3,887	15,008	15,656
December 31, 2005	53,861	27,386	36,363
December 31, 2006	51,445	22,702	31,276

Proved developed reserves are proved reserves expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are proved reserves that require incremental capital expenditures to recover. Natural gas is converted to barrels of oil equivalent using a conversion factor of six thousand cubic feet per barrel.

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

Standardized measure of discounted future net cash flows relating to proved oil and gas reserves

The standardized measure of discounted future net cash flows presented in the following table was computed using year-end prices and costs and a 10% discount factor. However, the Company cautions that actual future net cash flows may vary considerably from these estimates. Although the Company s estimates of total proved reserves, development costs and production rates were based on the best available information, the development and production of the oil and gas reserves may not occur in the periods assumed. Actual prices realized, costs incurred and production quantities may vary significantly from those used. Therefore, such estimated future net cash flows computations should not be considered to represent the Company s estimate of the expected revenues or the current value of existing proved reserves.

	December 31,		
	2004	2005	2006
		(in thousands)	
Historical			
Future cash inflows	$ 3,562,595	$ 6,332,258	$ 5,244,078
Future production costs	(1,280,180)	(1,808,654)	(1,763,573)
Future development and abandonment costs	(113,390)	(434,249)	(466,057)
Future net cash flows	2,169,025	4,089,355	3,014,448
10% annual discount for estimated timing of cash flows	(1,054,705)	(1,884,980)	(1,429,976)
Standardized measure of discounted future net cash flows	$ 1,114,320	$ 2,204,375	$ 1,584,472
Pro forma for income tax			
Future cash inflows	$ 3,562,595	$ 6,332,258	$ 5,244,078
Future production costs	(1,280,180)	(1,808,654)	(1,763,573)
Future development and abandonment costs	(113,390)	(434,249)	(466,057)
Future income taxes	(775,620)	(1,497,230)	(1,061,163)
Future net cash flows pro forma for income taxes	1,393,405	2,592,125	1,953,285
10% annual discount for estimated timing of cash flows	(677,450)	(1,194,834)	(926,588)
Standardized measure of discounted future net cash flows	$ 715,955	$ 1,397,291	$ 1,026,697

The year-end weighted average oil price utilized in the computation of future cash inflows was $40.46, $55.87, and $47.85 per barrel at December 31, 2004, 2005 and 2006, respectively. The year-end weighted average natural gas price utilized in the computation of future cash inflows was $4.97, $7.60, and $4.54 per Mcf at December 31, 2004, 2005 and 2006, respectively. Future cash flows are reduced by estimated future costs to develop and to produce the proved reserves, as well as certain abandonment costs, based on year-end cost estimates assuming continuation of existing economic conditions.

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

Income taxes were not computed at December 31, 2004, 2005 or 2006, as the Company elected S-corporation status effective June 1, 1997. The changes in the aggregate standardized measure of discounted future net cash flows attributable to the Company s proved oil and gas reserves are presented below for each of the past three years (in thousands):

	2004	2005	2006
Standardized measure of discounted future net cash flows at the beginning of the year	$ 815,224	$ 1,114,320	$ 2,204,375
Extensions, discoveries and improved recovery, less related costs	108,634	566,858	138,119
Revisions of previous quantity estimates	57,525	43,338	5,455
Changes in estimated future development and abandonment costs	(44,323)	(317,286)	(139,623)
Purchase (sales) of minerals in place	1,311	(8,714)	5,953
Net changes in prices and production costs	210,323	870,255	(520,756)
Accretion of discount	81,522	111,432	220,438
Sales of oil and gas produced, net of production costs	(125,850)	(287,817)	(383,405)
Development costs incurred during the period	12,604	48,894	123,971
Change in timing of estimated future production, and other	(2,650)	63,095	(70,055)
Net Change	299,096	1,090,055	(619,903)
Standardized measure of discounted future net cash flows at the end of the year	$ 1,114,320	$ 2,204,375	$ 1,584,472

15. Recent Events (Unaudited)

Concurrent with a proposed initial public offering, the Company will convert from a subchapter S-corporation to a subchapter C-corporation. In connection with this conversion, a charge to earnings (estimated to be $178.8 million if the conversion occurred as of December 31, 2006) will be recorded to recognize deferred taxes.

On January 10, 2007, the Company declared cash dividends of approximately $18.8 million to its shareholders for tax purposes and, subject to forfeiture, to holders of unvested restricted stock. Of this amount, $124,000 was charged to compensation expense related to its restricted stock liability. On January 31, 2007, the Company paid $18.7 million of the dividends declared. The unpaid balance of $86,000 relates to unvested restricted stock and is accrued and will be paid as the restricted stock vests.

On March 6, 2007 the Company declared a cash dividend of approximately $33.3 million payable in April 2007 to its shareholders of record as of March 15, 2007, for tax purposes and, subject to forfeiture, to holders of unvested restricted stock.

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Glossary of Oil and Natural Gas Terms

The terms defined in this section are used throughout this prospectus:

Bbl. One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or natural gas liquids.

Bcf. One billion cubic feet of natural gas.

Boe. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.

British thermal unit. The heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Basin. A large natural depression on the earth s surface in which sediments generally brought by water accumulate.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Development well. A well drilled within the proved area of a natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Enhanced recovery. The recovery of oil and natural gas through the injection of liquids or gases into the reservoir, supplementing its natural energy. Enhanced recovery methods are often applied when production slows due to depletion of the natural pressure.

Environmental Assessment (EA). An environmental assessment, a study that can be required pursuant to federal law to assess the potential direct, indirect and cumulative impacts of a project.

Environmental Impact Statement (EIS). An environmental impact statement, a more detailed study that can be required pursuant to federal law of the potential direct, indirect and cumulative impacts of a project that may be made available for public review and comment.

Exploratory well. A well drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

Formation. A layer of rock which has distinct characteristics that differ from nearby rock.

Horizontal drilling. A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

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Infill wells. Wells drilled into the same pool as known producing wells so that oil or natural gas does not have to travel as far through the formation.

MBbl. One thousand barrels of crude oil, condensate or natural gas liquids.

Mcf. One thousand cubic feet of natural gas.

MMBbl. One million barrels of crude oil, condensate or natural gas liquids.

MMBoe. One million Boe.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

NYMEX. The New York Mercantile Exchange.

Net acres. The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

Overpressured. A subsurface formation that exerts an abnormally high formation pressure on a wellbore drilled into it.

PUD. Proved undeveloped.

PV-10. When used with respect to oil and natural gas reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the SEC. PV-10 is a non-GAAP financial measure. However, our PV-10 and our standardized measure of discounted future net cash flows (the most directly comparable measure calculated and presented in accordance with GAAP) are equivalent because we are a subchapter S-corporation until the closing date of this offering.

Primary recovery. The period of production in which oil moves from its reservoir through the wellbore under naturally occurring reservoir pressure.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved reserves. The estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved undeveloped reserves (PUD). Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Recompletion. The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.

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Spacing. The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

Standardized Measure. Discounted future net cash flows estimated by applying year-end prices to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the oil and gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

Unit. The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

Waterflood. The injection of water into an oil reservoir to push additional oil out of the reservoir rock and into the wellbores of producing wells. Typically an enhanced recovery process.

Wellbore. The hole drilled by the bit that is equipped for oil or gas production on a completed well. Also called well or borehole.

Working interest. The right granted to the lessee of a property to explore for and to produce and own oil, gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

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February 19, 2007

Continental Resources, Inc.

302 North Independence

Enid, Oklahoma 73702

Gentlemen:

At your request we have prepared an estimate of the proved reserves and future production and income attributable to certain leasehold interests of Continental Resources, Inc. as of December 31, 2006. The properties evaluated by Ryder Scott Company, L. P. (Ryder Scott) were selected by Continental Resources, and account for approximately 82.9 percent of the future net income discounted at 10 percent attributable to the proved reserves as of December 31, 2006. The income data have been estimated using the Securities and Exchange Commission (SEC) guidelines for future cost and price parameters.

The estimated reserve quantities and future income quantities presented in this report are related to hydrocarbon prices. December 31, 2006 hydrocarbon prices were used in the preparation of this report; however, actual future prices may vary significantly from December 31, 2006 prices due to a combination of economic and political forces. Therefore, quantities of reserves actually recovered and quantities of income actually received may differ significantly from the estimated quantities presented in this report. The results are summarized as follows:

SEC PARAMETERS

Estimated Proved Net Reserve and Income Data

Certain Leasehold Interests of

Continental Resources, Inc.

As of December 31, 2006

	Net Oil** M Barrels	Net Gas** MMCF	Future Net** Income M$	Discounted** FNI @ 10%M$
Evaluated by Ryder Scott	86,682	70,226	$ 2,499,633	$ 1,313,670

Evaluated by				
Continental Resources	11,356	51,639	$ 514,815	$ 270,802
Total Proved Reserves	98,038	121,865	$ 3,014,448	$ 1,584,472

* Ryder Scott has not reviewed the reserves and cashflow projections for those properties evaluated by Continental Resources, Inc. Ryder Scott has included these values at the request of Continental Resources, Inc. and expresses no opinion as to the reasonableness of these values.

** From TRC Consultants : PhdWin Decline Analysis

Liquid hydrocarbons are expressed in standard 1000 barrels. All gas volumes are sales gas expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas where the gas reserves are located. No attempt has been made to quantify or otherwise account for any accumulated gas production imbalances that may exist.

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Reserves Included in This Report

The *proved reserves* included herein conform to the definition as set forth in the Securities and Exchange Commission s Regulation S-X Part 210.4-10 (a) as clarified by subsequent Commission Staff Accounting Bulletins.

Estimates of Reserves

In general, the reserves included herein were estimated by performance methods or the volumetric method; however, other methods were used in certain cases where characteristics of the data indicated such other methods were more appropriate in our opinion. The reserves estimated by the performance method utilized extrapolations of various historical data in those cases where such data were definitive. Reserves were estimated by the volumetric method in those cases where there were inadequate historical performance data to establish a definitive trend or where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate.

The reserves included in this report are estimates only and should not be construed as being exact quantities. They may or may not be actually recovered, and if recovered, the revenues therefrom and the actual costs related thereto could be more or less than the estimated amounts. Moreover, estimates of reserves may increase or decrease as a result of future operations.

Projection Rates

Initial production rates are based on the current producing rates for those reservoirs now on production. Test data and other related information was used to estimate the anticipated initial production rates for those wells or locations, which are not currently producing. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. The future anticipated decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates. For reserves not yet on production, sales were projected to commence at an anticipated date of delivery, which was furnished by Continental Resources, Inc.

The future production rates from reservoirs now on production may be more or less than estimated because of changes in market demand or allowables set by regulatory bodies. Wells or locations, which are not currently producing, may start producing earlier or later than anticipated in our estimates of their future production rates.

Hydrocarbon Prices

Continental Resources, Inc. has utilized hydrocarbon prices in effect at December 29, 2006, the crude oil price was $61.05 per barrel and the spot gas price was $6.30 per MMBTU. Product prices, which were actually used for each property, reflect adjustment from the above stated prices for gravity, quality, local conditions, and/or distance from market. These prices were held constant to depletion of the properties. In accordance with Securities and Exchange Commission guidelines, changes in hydrocarbon prices subsequent to December 29, 2006 were not considered in this report. Ryder Scott has not performed a detailed study of the product prices and makes no warranty for the product prices utilized in this report.

Costs

Continental Resources, Inc supplied operating costs for the leases and wells in this report. When applicable, the operating costs include a portion of general and administrative costs allocated directly to the leases and wells under terms of operating agreements. Development costs were furnished by Continental Resources, Inc. and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The current operating and development costs were held constant throughout the life of the properties. Continental Resources, Inc. has used an estimate of zero abandonment costs after salvage value for all properties in this report. Ryder Scott has not performed a detailed study of the operating and development costs and makes no warranty for the costs utilized in this report.

General

Ryder Scott Company performed the reserve analysis and generated the projection of future production presented in this report. However, at the request of Continental Resources, Inc., the economic analyses were performed using TRC Consultants PhdWin Decline Analysis. Ryder Scott Company, L. P. has made every attempt to confirm that the values used for scheduling production were correct. However, the internal calculations of this program were accepted without verification. In addition, Ryder Scott Company has accepted the ownership interests; costs and prices supplied by Continental Resources, Inc. as correct and have not attempted to verify those values. Ryder Scott Company has not attempted to verify the accuracy of the economic output from TRC Consultants PhdWin Decline Analysis.

As prepared by Continental Resources, Inc., the tables presented in this report are generated by TRC Consultants PhdWin Decline Analysis and are located behind the Appendix tab. The summary report contains individual tables of estimated production and income by year beginning January 1, 2007 by reserve category for the properties evaluated by Ryder Scott. These tables are located behind the tab titled Grand Summary Projections . A one-line summary of net reserves and income data for each of the subject properties is presented behind the tab titled One-Line Summaries . A one-line summary of reserves and income data ranked by BTAX cashflow discounted at 10 percent is behind the Property Ranking tab.

While it may reasonably be anticipated that the prices received by Continental Resources, Inc. for the sale of its production may be higher or lower than the prices used in this evaluation as described above, and the operating costs relating to such production may also increase above existing levels, such increases or decreases in prices and costs were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

The reserve estimates presented herein are based upon a detailed study of the top valued properties in which Continental Resources, Inc. owns an interest; however, we have not made any field examination of the properties. Continental Resources, Inc. has informed us that they have furnished us all of the accounts, records, geological and engineering data and reports and other data required for this investigation. The production data, ownership interests, prices, costs and other factual information furnished to Ryder Scott Company, L. P. by Continental Resources, Inc. in connection with this investigation were accepted without independent verification.

Neither Ryder Scott Company, L. P., nor any of its employees has any interest in the subject properties and neither the employment to make this study nor the compensation is contingent on our estimates of reserves and future income for the subject properties.

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This report was prepared for the exclusive use of Continental Resources, Inc. The data, work papers and maps used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,
RYDER SCOTT COMPANY, L.P.

Scott J. Wilson, P.E.
Vice President

Approved:

Larry T. Nelms, P.E.

Managing Senior Vice President

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29,500,000 Shares

Continental Resources, Inc.

Common Stock

PROSPECTUS

JPMorgan

Merrill Lynch & Co.

Citi

UBS Investment Bank

Deutsche Bank Securities

Raymond James

, 2007

You should rely only on the information contained in this prospectus. We have not authorized anyone to provide you with information different from that contained in this prospectus. We and the selling shareholder are offering to sell, and seeking offers to buy, shares of common stock only in jurisdictions where offers and sales are permitted. The information contained in this prospectus is accurate only as of the date of this prospectus, regardless of the time of delivery of this prospectus or of any sale of our common stock.

No action is being taken in any jurisdiction outside the United States to permit a public offering of the common stock or possession or distribution of this prospectus in that jurisdiction. Persons who come into possession of this prospectus in jurisdictions outside the United States are required to inform themselves about and to observe any restrictions as to this offering and the distribution of this prospectus applicable to that jurisdiction.

Until , 2007, all dealers that buy, sell or trade in our common stock, whether or not participating in this offering, may be required to deliver a prospectus. This is in addition to the dealers obligation to deliver a prospectus when acting as underwriters and with respect to their unsold allotments or subscriptions.

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Part II

Information Not Required in Prospectus

Item 13. Other Expenses of Issuance and Distribution

The following table sets forth the costs and expenses to be paid by us in connection with the sale of the shares of common stock being registered hereby. All amounts are estimates except for the SEC registration fee, the NASD filing fee and the NYSE listing fee.

Securities and Exchange Commission registration fee	$ 62,620
NASD filing fee	75,500
NYSE listing fee	250,000
Accounting fees and expenses	480,000
Legal fees and expenses	725,000
Printing and engraving expenses	252,975
Transfer agent and registrar fees and expenses	5,000
Total	$ 1,851,095

Item 14. Indemnification of Directors and Officers

Continental Resources, Inc. (the Registrant) is incorporated in Oklahoma. Section 1031 of the Oklahoma General Corporation Act (the OGCA) authorizes a court to award, or a corporation s board of directors to grant, indemnity under certain circumstances to directors, officers employees or agents in connection with actions, suits or proceedings, by reason of the fact that the person is or was a director, officer, employee or agent, against expenses and liabilities incurred in such actions, suits or proceedings so long as they acted in good faith and in a manner the person reasonable believed to be in, or not opposed to, the best interests of the company, and with respect to any criminal action if they had no reasonable cause to believe their conduct was unlawful. With respect to suits by or in the right of such corporation, however, indemnification is generally limited to attorneys fees and other expenses and is not available if such person is adjudged to be liable to such corporation unless the court determines that indemnification is appropriate.

In connection with the closing of the offering, the Registrant will amend and restate its certificate of incorporation and bylaws. As permitted by the OGCA, the Registrant s amended and restated certificate of incorporation will include a provision that eliminates the personal liability of its directors to the Registrant or its shareholders for monetary damages for breach of fiduciary duty as a director, except for liability:

for any breach of the director s duty of loyalty to it or its shareholders;

for acts or omissions not in good faith or that involve intentional misconduct or a knowing violation of law;

under section 1053 of the OGCA regarding unlawful dividends and stock purchases; or

for any transaction for which the director derived an improper personal benefit.

As permitted by the OGCA, the Registrant s amended and restated certificate of incorporation will provide that the Registrant is required to indemnify its directors and officers to the fullest extent permitted by the OGCA.

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As permitted by Oklahoma law, the Registrant s amended and restated bylaws will provide that:

- the Registrant may indemnify its other employees and agents, subject to very limited exceptions;
- the Registrant is required to advance expenses (including without limitation, attorneys fees), as incurred, to its directors and officers in connection with a legal proceeding, subject to very limited exceptions; and
- the rights conferred in the Registrant s bylaws are not exclusive.

The indemnification provisions in the Registrant s amended and restated certificate of incorporation may be sufficiently broad to permit indemnification of its directors and officers for liabilities arising under the Securities Act.

Under Oklahoma law, corporations also have the power to purchase and maintain insurance for directors, officers, employees and agents.

Prior to the closing of the offering, it is contemplated that the Registrant and its subsidiaries will obtain liability insurance policies which indemnify their directors and officers against loss arising from claims by reason of their legal liability for acts as such directors and officers, subject to limitations and conditions as set forth in the policies.

The Registrant has entered into written indemnification agreements with all of its directors and executive officers (including each of its named executive officers). These indemnification agreements are intended to permit indemnification to the fullest extent permitted by the OGCA. It is possible that the applicable law could change the degree to which indemnification is expressly permitted.

The indemnification agreements cover expenses (including attorneys fees), judgments, fines and amounts paid in settlement incurred as a result of the fact that such person, in his or her capacity as a director or officer, is made or threatened to be made a party to any suit or proceeding. The indemnification agreements generally cover claims relating to the fact that the indemnified party is or was an officer, director, employee or agent of the Registrant or any of its affiliates, or is or was serving at the Registrant s request in such a position for another entity. The indemnification agreements also obligate the Registrant to promptly advance all reasonable expenses incurred in connection with any claim. The indemnitee is, in turn, obligated to reimburse the Registrant for all amounts so advanced if it is later determined that the indemnitee is not entitled to indemnification. The indemnification provided under the indemnification agreements is not exclusive of any other indemnity rights; however, double payment to the indemnitee is prohibited.

The Registrant will not be obligated to indemnify the indemnitee with respect to claims brought by the indemnitee against it without prior approval of a majority of the Registrant s board of directors, except for claims brought by the Indemnitee to enforce his or her rights under the indemnification agreement.

Under the underwriting agreement that the Registrant will enter into in connection with the offering, the underwriters will be obligated, under certain circumstances, to indemnify directors and officers of the registrant against certain liabilities, including liabilities under the Securities Act. Reference is made to the form of underwriting agreement filed as Exhibit 1.1 hereto.

The foregoing discussion of the Registrant s amended and restated certificate of incorporation and bylaws and Oklahoma law is not intended to be exhaustive and is qualified in its entirety by such certificate of incorporation, bylaws or law.

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Item 15. Recent Sales of Unregistered Securities

During the past three years, the Registrant has issued unregistered securities to a limited number of persons, as described below. None of these transactions involved any underwriters or public offerings, and the Registrant believes that each of these transactions was exempt from registration requirements pursuant to Rule 701 of the Securities Act. The recipients of these securities represented their intention to acquire the securities for investment only and not with a view to or for sale in connection with any distribution thereof, and appropriate legends were affixed to the share certificates and instruments issued in these transactions.

During the year ended December 31, 2005, the Registrant issued options to purchase an aggregate of 275,000 shares of its common stock to certain of its executive officers under the Continental Resources, Inc. 2000 Stock Option Plan. During the year ended December 31, 2004, the Registrant issued options to purchase an aggregate of 220,000 shares of its common stock to certain of its executive officers under the Continental Resources, Inc. 2000 Stock Option Plan. The Registrant issued no options to purchase shares of its common stock under the Continental Resources, Inc. 2000 Stock Option Plan in 2006.

During the years ended December 31, 2005 and 2006 and during 2007, the Registrant also issued 990,517, 200,772 and 58,784 shares, respectively, of its restricted stock to certain of its executive officers, employees and directors under the Continental Resources, Inc. 2005 Long-Term Incentive Plan.

Item 16. Exhibits and Financial Statement Schedules

(a) The following exhibits are filed herewith:

Number	Exhibit
1.1**	Form of Underwriting Agreement.
3.1**	Form of Third Amended and Restated Certificate of Incorporation of Continental Resources, Inc.
3.2**	Form of Second Amended and Restated Bylaws of Continental Resources, Inc.
4.1**	Specimen Common Stock Certificate.
4.2**	Form of Registration Rights Agreement by and among Continental Resources, Inc., the Revocable Inter Vivos Trust of Harold G. Hamm, the Harold Hamm DST Trust and the Harold Hamm HJ Trust.
5.1***	Opinion of Crowe & Dunlevy, A Professional Corporation.
10.1**	Sixth Amended and Restated Credit Agreement among Union Bank of California, N.A., Guaranty Bank, FSB, Fortis Capital Corp., The Royal Bank of Scotland plc, other financial institutions and banks and Continental Resources, Inc. dated April 12, 2006.
10.2	Omnibus Agreement among Continental Resources, Inc., Hiland Partners, LLC, Harold Hamm, Hiland Partners GP, LLC, Continental Gas Holdings, Inc. and Hiland Partners, LP effective as of the closing of Hiland Partners, LP s initial public offering of common units (incorporated by reference to Exhibit 10.10 to the Annual Report on Form 10-K of Hiland Partners, LP filed on March 30, 2005, Commission File No. 000-51120).
10.3	

	Compression Services Agreement among Hiland Partners, LP and Continental Resources, Inc. effective as of January 28, 2005 (incorporated by reference to Exhibit 10.3 to the Annual Report on Form 10-K of Hiland Partners, LP filed on March 30, 2005, Commission File No. 000-51120).
10.4	Gas Purchase Contract between Continental Resources, Inc. and Hiland Partners, LP November 8, 2005 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Hiland Partners, LP filed on November 10, 2005, Commission File No. 000-51120).

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Number	Exhibit
10.5	Strategic Customer Relationship Agreement among Complete Energy Services, Inc., CES Mid-Continent Hamm, Inc. and Continental Resources, Inc. dated October 14, 2004 (incorporated by reference to Exhibit 10.12 to the Registration Statement on Form S-1 of Complete Production Services, Inc. filed on November 15, 2005, Commission File No. 333-128750).
10.6**	Continental Resources, Inc. 2000 Stock Option Plan.
10.7**	First Amendment to Continental Resources, Inc. 2000 Stock Option Plan.
10.8**	Form of Incentive Stock Option Agreement.
10.9**	Amended and Restated Continental Resources, Inc. 2005 Long-Term Incentive Plan effective as of April 3, 2006.
10.10**	Form of Restricted Stock Award Agreement.
10.11**	Amended and Restated Employment Agreement between Continental Resources, Inc. and Mark E. Monroe dated April 3, 2006.
10.12**	Form of Indemnification Agreement between Continental Resources, Inc. and each of the directors and executive officers thereof.
10.13**	Membership Interest Assignment Agreement by and between Continental Resources, Inc., the Harold Hamm Revocable Inter Vivos Trust, the Harold Hamm HJ Trust and the Harold Hamm DST Trust dated March 30, 2006.
21.1*	Subsidiaries of Continental Resources, Inc. (updating Exhibit 21.1 to Amendment No. 1 to the Registration Statement on Form S-1 of Continental Resources, Inc. filed on April 14, 2006, Commission File No. 333-132257).
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Ryder Scott Company, L.P.
23.3***	Consent of Crowe & Dunlevy, A Professional Corporation (included in Exhibit 5.1).
23.4**	Consent of Vinson & Elkins L.L.P.
24.1**	Power of Attorney.

* Filed herewith.
** Previously filed.
*** To be filed by amendment.

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Item 17. Undertakings

The undersigned Registrant hereby undertakes to provide to the underwriters at the closing specified in the underwriting agreement certificates in such denominations and registered in such names as required by the underwriters to permit prompt delivery to each purchaser.

Insofar as indemnification for liabilities arising under the Securities Act may be permitted to directors, officers and controlling persons of the Registrant pursuant to the provisions described in Item 14 above, or otherwise, the Registrant has been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Securities Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the Registrant of expenses incurred or paid by a director, officer or controlling person of the Registrant in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered hereunder, the Registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Securities Act and will be governed by the final adjudication of such issue.

The undersigned Registrant hereby undertakes that:

(1) For purposes of determining any liability under the Securities Act, the information omitted from the form of prospectus filed as part of this Registration Statement in reliance upon Rule 430A and contained in a form of prospectus filed by the Registrant pursuant to Rule 424(b)(1) or (4) or 497(h) under the Securities Act shall be deemed to be part of this Registration Statement as of the time it was declared effective; and

(2) For the purpose of determining any liability under the Securities Act, each post-effective amendment that contains a form of prospectus shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at the time shall be deemed to be the initial bona fide offering thereof.

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Signatures

Pursuant to the requirements of the Securities Act of 1933, the Registrant has duly caused this Amendment No. 6 to Registration Statement on Form S-1 to be signed on its behalf by the undersigned, thereunto duly authorized, in Enid, Oklahoma, on this 17th day of April, 2007.

CONTINENTAL RESOURCES, INC.

By: /s/ Mark E. Monroe

Name: **Mark E. Monroe**
Title: **President and Chief Operating Officer**

Pursuant to the requirements of the Securities Act of 1933, this Amendment No. 6 to Registration Statement on Form S-1 has been signed by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
* **Harold G. Hamm**	Chairman, Chief Executive Officer and Director (principal executive officer)	April 17, 2007
/s/ Mark E. Monroe **Mark E. Monroe**	President, Chief Operating Officer and Director	April 17, 2007
* **John D. Hart**	Vice President, Chief Financial Officer and Treasurer (principal financial and accounting officer)	April 17, 2007
* **Jack H. Stark**	Senior Vice President Exploration and Director	April 17, 2007

*		
Robert J. Grant	Director	April 17, 2007
*		
George S. Littell	Director	April 17, 2007
*		
Lon McCain	Director	April 17, 2007
*		
H. R. Sanders, Jr.	Director	April 17, 2007

*By: /s/ Mark E. Monroe

Mark E. Monroe

Attorney-in-Fact

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Exhibit Index

Number	Exhibit
1.1**	Form of Underwriting Agreement.
3.1**	Form of Third Amended and Restated Certificate of Incorporation of Continental Resources, Inc.
3.2**	Form of Second Amended and Restated Bylaws of Continental Resources, Inc.
4.1**	Specimen Common Stock Certificate.
4.2**	Form of Registration Rights Agreement by and among Continental Resources, Inc., the Revocable Inter Vivos Trust of Harold G. Hamm, the Harold Hamm DST Trust and the Harold Hamm HJ Trust.
5.1***	Opinion of Crowe & Dunlevy, A Professional Corporation.
10.1**	Sixth Amended and Restated Credit Agreement among Union Bank of California, N.A., Guaranty Bank, FSB, Fortis Capital Corp., The Royal Bank of Scotland plc, other financial institutions and banks and Continental Resources, Inc. dated April 12, 2006.
10.2	Omnibus Agreement among Continental Resources, Inc., Hiland Partners, LLC, Harold Hamm, Hiland Partners GP, LLC, Continental Gas Holdings, Inc. and Hiland Partners, LP effective as of the closing of Hiland Partners, LP s initial public offering of common units (incorporated by reference to Exhibit 10.10 to the Annual Report on Form 10-K of Hiland Partners, LP filed on March 30, 2005, Commission File No. 000-51120).
10.3	Compression Services Agreement among Hiland Partners, LP and Continental Resources, Inc. effective as of January 28, 2005 (incorporated by reference to Exhibit 10.3 to the Annual Report on Form 10-K of Hiland Partners, LP filed on March 30, 2005, Commission File No. 000-51120).
10.4	Gas Purchase Contract between Continental Resources, Inc. and Hiland Partners, LP dated November 8, 2005 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Hiland Partners, LP filed on November 10, 2005, Commission File No. 000-51120).
10.5	Strategic Customer Relationship Agreement among Complete Energy Services, Inc., CES Mid-Continent Hamm, Inc. and Continental Resources, Inc. dated October 14, 2004 (incorporated by reference to Exhibit 10.12 to the Registration Statement on Form S-1 of Complete Production Services, Inc. filed on November 15, 2005, Commission File No. 333-128750).
10.6**	Continental Resources, Inc. 2000 Stock Option Plan.
10.7**	First Amendment to Continental Resources, Inc. 2000 Stock Option Plan.
10.8**	Form of Incentive Stock Option Agreement.
10.9**	Amended and Restated Continental Resources, Inc. 2005 Long-Term Incentive Plan effective as of April 3, 2006.
10.10**	Form of Restricted Stock Award Agreement.
10.11**	Amended and Restated Employment Agreement between Continental Resources, Inc. and Mark E. Monroe dated April 3, 2006.
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23.1*	Consent of Grant Thornton LLP.
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23.3***	Consent of Crowe & Dunlevy, A Professional Corporation (included in Exhibit 5.1).
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24.1**	Power of Attorney.

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** Previously filed.
*** To be filed by amendment.

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