SANDRIDGE ENERGY INC
Form S-1
January 30, 2008

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As filed with the Securities and Exchange Commission on January 30, 2008

Registration No. 333-

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form S-1
REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933

SandRidge Energy, Inc.
(Exact name of registrant as specified in its charter)

Delaware	**1311**	**20-8084793**
(State or other jurisdiction of incorporation or organization)	*(Primary Standard Industrial Classification Code Number)*	*(I.R.S. Employer Identification No.)*

1601 N.W. Expressway, Suite 1600
Oklahoma City, Oklahoma 73118
(405) 753-5500
(Address, including zip code, and telephone number, including area code, of registrant s principal executive offices)

Tom L. Ward
Chairman, Chief Executive Officer and President
1601 N.W. Expressway, Suite 1600
Oklahoma City, Oklahoma 73118
(405) 753-5500
(Name, address, including zip code, and telephone number, including area code, of agent for service)

Copies to:

Vinson & Elkins L.L.P.
2500 First City Tower, 1001 Fannin
Houston, Texas 77002
(713) 758-2222
Attn: T. Mark Kelly

Approximate date of commencement of proposed sale to the public: As soon as practicable after this Registration Statement becomes effective.

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, please check the following box. þ

If this form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, please check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities to be Registered	Amount to be Registered	Proposed Maximum Offering Price per Share(2)	Proposed Maximum Aggregate Offering Price(2)	Amount of Registration Fee
Common Stock, par value $0.001	7,930,369(1)	$30.98	$245,682,832	$9,656

(1) Includes 1,180,107 shares of common stock currently outstanding and 6,750,262 shares of common stock issuable upon the conversion of our 7.75% convertible preferred stock.

(2) Estimated solely for the purpose of calculating the registration fee in accordance with Rule 457(c) under the Securities Act 1933. The price per share and aggregate offering prices for the shares registered hereby are calculated on the basis of $30.98, which is the average of the high and low prices reported on the New York Stock Exchange on January 24, 2008.

The Registrant hereby amends this Registration Statement on such date or dates as may be necessary to delay its effective date until the Registrant shall file a further amendment which specifically states that this Registration Statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933 or until the Registration Statement shall become effective on such date as the Commission, acting pursuant to said Section 8(a), may determine.

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SUBJECT TO COMPLETION, DATED JANUARY 30, 2008

Prospectus

7,930,369 Shares

SandRidge Energy, Inc.

Common Stock

This prospectus relates to up to 7,930,369 shares of the common stock of SandRidge Energy, Inc., which may be offered for sale by the selling stockholders named in this prospectus. The shares of common stock offered by this prospectus were acquired by the selling stockholders, or are issuable upon conversion of securities acquired by the selling stockholders, in connection with our December 2005, November 2006 and March 2007 private placements. We are registering the offer and sale of the shares of common stock to satisfy registration rights we have granted.

We are not selling any shares of common stock under this prospectus and will not receive any proceeds from the sale of common stock by the selling stockholders. The shares of common stock to which this prospectus relates may be offered and sold from time to time directly from the selling stockholders or alternatively through underwriters or broker-dealers or agents. The shares of common stock may be sold in one or more transactions, at fixed prices, at prevailing market prices at the time of sale or at negotiated prices. Please read Plan of Distribution.

Our common stock is listed on the New York Stock Exchange under the symbol SD.

Investing in our common stock involves a high degree of risk. See Risk Factors beginning on page 13.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved these securities or determined if this prospectus is accurate or complete. Any representation to the contrary is a criminal offense.

The date of this prospectus is , 2008

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You should rely only on the information contained in this prospectus or to which we have referred you. We and the selling stockholders have not authorized anyone to provide you with different information. We and the selling stockholders are not making an offer of these securities in any jurisdiction where such offer or sale is not permitted. You should assume that the information contained in this prospectus is accurate as of the date on the front of this prospectus only. Our business, financial condition, results of operations and prospects may have changed since that date.

This prospectus is part of a shelf registration statement that we filed with the Securities and Exchange Commission (the SEC) for a continuous offering. Under this prospectus, the selling stockholders may, from time to time, sell the shares of our common stock described in this prospectus in one or more offerings. This prospectus may be supplemented from time to time to add, update or change information in this prospectus. Any statement contained in this prospectus will be deemed to be modified or superseded for the purposes of this prospectus to the extent that a statement contained in a prospectus supplement modifies such statement. Any statement so modified will be deemed to constitute a part of this prospectus only as so modified, and any statement so modified will be deemed to constitute a part of this prospectus.

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The registration statement containing this prospectus, including the exhibits to the registration statement, provides additional information about us, the selling stockholders and the shares of our common stock offered under this prospectus. The registration statement, including the exhibits, can be read on the SEC website or at the SEC offices mentioned under the heading Where You Can Find More Information.

Information contained in our website does not constitute part of this prospectus.

SandRidge Energy, Inc., our logo and other trademarks mentioned in this prospectus are the property of their respective owners.

This prospectus includes market share and industry data that we obtained from internal research, publicly available information and industry publications and surveys. Our internal research and forecasts are based upon management s understanding of industry conditions. Industry surveys and publications generally state that the information contained therein has been obtained from sources believed to be reliable.

SUMMARY

This summary contains basic information about us and the offering. Because it is a summary, it does not contain all of the information that you should consider before investing in our common stock. You should read and carefully consider this entire prospectus before making an investment decision, especially the information presented under the heading Risk Factors and the consolidated and pro forma condensed combined financial statements and the accompanying notes thereto included elsewhere in this prospectus. We have provided definitions for some of the natural gas and oil industry terms used in this prospectus in the Glossary of Natural Gas and Oil Terms on page A-1 of this prospectus. Natural gas equivalents are determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids. Unless otherwise noted, all natural gas amounts are net of CO_2 or have CO_2 levels within pipeline specifications.

On December 29, 2006, we merged with and into a newly formed Delaware corporation and changed our name from Riata Energy, Inc. to SandRidge Energy, Inc. The purpose of the merger was to change our jurisdiction of incorporation from Texas to Delaware. Except as otherwise indicated or required by the context, references in this prospectus to we, us, our, SandRidge, Riata, or the Company refer to the business of SandRidge Energy, Inc. subsidiaries after the merger and its predecessor, Riata Energy, Inc., and its subsidiaries prior to the merger.

Overview

SandRidge is a rapidly expanding independent natural gas and oil company concentrating in exploration, development and production activities. We are focused on expanding our continuing exploration and exploitation of our significant holdings in an area of West Texas that we refer to as the West Texas Overthrust, or WTO, a natural gas prone geological region where we have operated since 1986 that includes the Piñon Field and our South Sabino and Big Canyon prospects. We intend to add to our existing reserve and production base in this area by increasing our development drilling activities in the Piñon Field and our exploration program in other prospects that we have identified. As a result of our 2006 acquisitions, including the NEG acquisition, we have nearly tripled our net acreage position in the WTO since January 2006. We believe that we are the largest operator and producer in the WTO and have assembled the largest acreage position in the area. We also operate significant interests in the Cotton Valley Trend in East Texas, the Gulf Coast area, the Gulf of Mexico and the Piceance Basin of Colorado.

We have assembled an extensive natural gas and oil property base in which we have identified over 4,500 potential drilling locations including over 2,600 in the WTO. As of June 30, 2007, our proved reserves were 1,174.0 Bcfe, of which 82% were natural gas and 97.5% of which were prepared by independent petroleum engineers. We had 1,469 gross (1,040 net) producing wells, substantially all of which we operate. As of September 30, 2007, we had interests in approximately 1,112,231 gross (763,032 net) natural gas and oil leased acres. We had 30 rigs drilling in the WTO as of September 30, 2007.

We also operate businesses that are complementary to our primary exploration, development and production activities, which provides us with operational flexibility and an advantageous cost structure. We own a fleet of 32 drilling rigs, three of which are currently being retrofitted. In addition, we are party to a joint venture that owns an additional twelve rigs, eleven of which are currently operating. We own related oil field services businesses, gas gathering and treating facilities and a marketing business. We also capture and supply CO_2 to support our tertiary oil recovery projects undertaken by us or third-parties. These assets are primarily located in our primary operating area in West Texas.

We expanded our management team significantly in 2006. Tom L. Ward, the co-founder and former President and Chief Operating Officer of Chesapeake Energy Corporation (Chesapeake), purchased a significant ownership interest in us June 2006 and joined us as Chief Executive Officer and Chairman of the Board. During Mr. Ward s 17 year tenure at Chesapeake, Chesapeake became one of the most active onshore drillers in the United States. From 1998 to 2005, Chesapeake drilled over 6,500 wells. Since Mr. Ward joined us, we have added eight new executive officers, substantially all of whom have experience at public exploration and production companies. We have also added key professionals in exploration, operations, land, accounting and finance.

In addition, we significantly increased our proved reserves and producing properties through the acquisition of NEG Oil and Gas LLC, or NEG, in November 2006. NEG owned core assets in the Val Verde and Permian Basins of West Texas, including overlapping or contiguous interests in the properties that we own in the WTO.

Our estimated capital expenditures for 2008 of approximately $1,250 million include $1,100 million allocated to exploration and development (including land and seismic acquisitions and our tertiary recovery operations), $50 million allocated to drilling and oil field services and $100 million allocated to midstream operations. Approximately $622 million of our 2008 capital expenditures will be spent on our Piñon Field development and our exploratory projects in the WTO (including land and seismic acquisitions). Under this capital budget, we plan to drill approximately 440 gross wells in 2008. The actual number of wells drilled and the amount of our 2008 capital expenditures will be dependent upon market conditions, availability of capital and drilling and production results.

Our Strategy

Our primary objective is to achieve long-term growth and maximize stockholder value over multiple business cycles by pursuing the following strategies:

Grow Through Exploration and Aggressive Drilling and Development of Existing Acreage. We expect to generate long-term reserve and production growth by exploring and aggressively drilling and developing our large acreage position. Our primary exploration and development focus will be in the WTO, where we have identified over 2,600 potential drilling locations and had 30 rigs operating as of September 30, 2007.

Apply Technological Improvements to Our Exploration and Development Program. We intend to enhance our drilling success rate and completion efficiency with improved 3-D seismic acquisition and interpretation technologies, together with advanced drilling, completion and production methods that historically have not been widely used in the under-explored WTO.

Seek Opportunistic Acquisitions in Our Core Geographic Area. Since January 2006, through acquisitions and leasing activities, we have nearly tripled our net acreage position in the WTO. We intend to continue to seek other opportunities to optimize and enhance our exploratory acreage position in the WTO and other strategic areas.

Reduce Costs, Enhance Returns and Maintain Operating Flexibility by Controlling Drilling Rigs and Midstream Assets. Our rig fleet enables us to aggressively develop our own acreage while maintaining the flexibility of a third-party contract drilling business. By controlling our fleet of drilling rigs and gathering and treating assets, we believe we will be able to better control overall costs and maintain a high degree of operational flexibility.

Capture and Utilize CO_2 for Tertiary Oil Recovery. We intend to capitalize on our access to CO_2 reserves and CO_2 flooding expertise to pursue enhanced oil recovery in mature oil fields in West Texas. By utilizing this CO_2 in our own tertiary recovery projects, we expect to recover additional oil that would have otherwise been abandoned following traditional waterfloods.

Competitive Strengths

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

Large Asset Base with Substantial Drilling Inventory. Our producing properties are characterized by long-lived predominantly natural gas reserves with established production profiles. Our estimated proved reserves of 1,174.0 Bcfe as of June 30, 2007 had a proved reserves to production ratio of approximately 19 years. Our core area of operations in the WTO has expanded to 581,961 gross (480,721 net) acres as of June 30, 2007. We have identified over 2,600 potential drilling locations in the WTO and believe that we will be able to expand the number of drilling locations in the remainder of the WTO through exploratory drilling and our use of 3-D seismic technology.

Geographically Concentrated Exploration and Development Operations. We intend to focus our drilling and development operations in the near term on the WTO to fully exploit this unique geological region. This geographic concentration allows us to establish economies of scale in both drilling and production operations to achieve lower production costs and generate increased cash flows from our producing properties. We believe our concentrated acreage position will enable us to organically grow our reserves and production for the next several years.

Experienced Management Team Focused on Delivering Long-term Stockholder Value. During 2006, we significantly expanded our management team when Tom L. Ward, co-founder and former president of Chesapeake, purchased a significant interest in us and became our Chairman and Chief Executive Officer. We also hired a new chief financial officer, three additional executive vice presidents and other additional senior executives. Our management team, board of directors and employees owned over 35% of our capital stock on a fully-diluted basis as of November 30, 2007, which we believe aligns their objectives with those of our stockholders.

High Degree of Operational Control. We operate over 95% of our production in the WTO, East Texas and the Gulf Coast area, which permits us to manage our operating costs and better control capital expenditures and the timing of development and exploitation activities.

Large Modern Fleet of Drilling Rigs. By controlling a large, modern and more efficient drilling fleet, we can develop our existing reserves and explore for new reserves on a more economic basis.

Our Businesses and Primary Operations

Exploration and Production

We explore for, develop and produce natural gas and oil reserves, with a focus on increasing our reserves and production in the WTO. We operate substantially all of our wells in the WTO. We also have significant operated leasehold positions in the Cotton Valley Trend in East Texas and the Gulf Coast area, as well as other non-core operating areas.

The following table identifies certain information concerning our exploration and production business as of September 30, 2007 unless otherwise noted:

Area	Estimated Net Proved Reserves (Bcfe)(1)	PV-10 (in millions)(1)(2)	Daily Production (Mmcfe/d)(3)	Proved Reserves/ Production(1)	Gross Acreage	Net Acreage	Number of Identified Potential Drilling Locations(1)
WTO	648.3	$ 1,190.9	69.1	25.7(4)	581,961	480,721	2,658
East Texas	156.3	310.2	26.3	16.3	48,606	32,557	566
Gulf Coast	104.5	410.7	44.2	6.6	53,464	34,765	51

Other(5)	265.9	646.9	37.1	19.5	428,200	214,989	1,298(6)
Total	1,174.0	$ 2,558.8	176.7	18.2	1,112,231	763,032	4,573

(1) Estimated net proved reserves, PV-10 and identified potential drilling locations are as of June 30, 2007.

(2) PV-10 generally differs from Standardized Measure of Discounted Net Cash Flows, or Standardized Measure, which is measured only at fiscal year end, because it does not include the effects of income taxes on future net revenues. For a reconciliation of PV-10 to Standardized Measure as of December 31, 2006, see Summary Historical Operating and Reserve Data. Our Standardized Measure was $1,440.2 million at December 31, 2006.

(3) Represents average daily net production for the third quarter 2007.

(4) Our proved reserves to production ratio in the WTO is significantly higher than our other areas of operation because of the high volume of our proved undeveloped reserves in this area. We expect this ratio to decrease as our production in the WTO increases.

(5) Includes our properties located offshore in the Gulf of Mexico, the Piceance Basin of Colorado, Other West Texas areas, including our tertiary oil recovery projects, and the Arkoma and Anadarko Basins and other non-strategic areas.

(6) Includes 828 identified potential drilling locations in the Piceance Basin.

West Texas Overthrust (WTO)

We have drilled and developed natural gas in the WTO since 1986. This area is located in Pecos and Terrell Counties in West Texas and provides for multi-pay exploration and development opportunities. The WTO has historically been largely under-explored due primarily to the remoteness and lack of infrastructure in the region, as well as historical limitations of conventional subsurface geological and geophysical methods. However, several fields including our prolific Piñon Field have been discovered. These fields have produced more than 255 Bcfe from less than 410 wells through September 30, 2007. We believe our access to and control of the necessary infrastructure combined with application of modern seismic techniques will allow us to identify further exploration and development opportunities in the WTO.

In May 2007, we began the first phase of 3-D seismic data acquisition in the WTO. This is the first of six phases planned over the next three years to acquire 1,300 square miles of 3-D seismic data in the WTO. We believe this 3-D seismic program may identify structural details of potential reservoirs, thus lowering the risk of exploratory drilling and improving completion efficiency. The first two phases of the seismic program covered 360 square miles and were completed in 2007.

We have aggressively acquired leasehold acreage in the WTO, nearly tripling our position since January 2006. As of September 30, 2007, we owned 581,961 gross (480,721 net) acres in the WTO, substantially all of which are along the leading edge of the WTO.

Piñon Field. The Piñon Field, located in Pecos County, is our most significant producing field, and accounts for 55% of our proved reserve base as of June 30, 2007, and approximately 75% of our 2007 exploration and development budget (including land and seismic acquisitions). The Piñon Field lies along the leading edge of the WTO.

As of June 30, 2007, our estimated proved natural gas and oil reserves in the Piñon Field were 648.3 Bcfe, 66% of which were proved undeveloped reserves. This field has produced approximately 205 Bcfe through September 30, 2007 and currently produces in excess of 118 gross Mmcfe per day.

Our interests in the Piñon Field included 351 producing wells as of September 30, 2007. We had an 84.4% average working interest in the producing area of Piñon Field and were running 30 drilling rigs in the Piñon Field as of September 30, 2007. As of June 30, 2007, we have identified 2,658 potential well locations in the Piñon Field, including 406 proved undeveloped drilling locations.

West Texas Overthrust Prospects. Through our exploratory drilling program, we have identified two prospect areas in the WTO, the South Sabino Prospect and the Big Canyon Prospect areas:

South Sabino Prospect Area. The South Sabino prospect area is located approximately twelve miles east of the Piñon Field. We have drilled two wells that appear to be on trend with the Piñon Field and are structurally higher against one of several thrust faults that make up the WTO. We began the first phase of our 3-D seismic program in this area in 2007.

Big Canyon Prospect Area. Located approximately 20 miles east of the Piñon Field along the WTO, this prospect area represents potential opportunities for future development.

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WTO Development Opportunities. The following table provides additional information concerning our development in the WTO:

Estimated Net PUD Reserves (Bcfe)(1)	Estimated Gross PUD Reserves (Bcfe)(1)	Gross PUD Drilling Locations(1)	Total Gross Drilling Locations (1)	Gross 2007 Drilling Locations	2007 Capital Expenditures Budget (in millions)(2)	2006 Year End Rigs Working	Rigs Working at 3Q 2007 End
431.1	675.2	406	2,658	207	$ 537	9	30

(1) As of June 30, 2007.

(2) Excludes capital expenditures related to land and seismic acquisitions.

East Texas Cotton Valley Trend. We own significant interests in the natural gas bearing Cotton Valley Trend, which covers a portion of East Texas and Northern Louisiana. The production in this region is generally characterized as long-lived. We intend to target the tight sands reservoirs and had six rigs running in this region at the end of 2007. As of June 30, 2007, East Texas accounted for 156.3 Bcfe of proved reserves and 566 potential drilling locations.

Gulf Coast Area. We own natural gas and oil interests in the Gulf Coast area, which encompasses the large coastal plain from the southernmost tip of Texas through the southern portion of Louisiana. Operations in this area are generally characterized as being comparatively higher risk and higher potential than in the other primary areas in which we operate, with successful wells typically having relatively higher initial production rates with steeper declines and shorter production lives. As of June 30, 2007, the Gulf Coast area accounted for 105.7 Bcfe of proved reserves and 51 potential drilling locations.

Other Exploration and Production Areas. We own significant natural gas and oil assets in the Gulf of Mexico and the Piceance Basin. Our Gulf of Mexico properties are located in bay and other shallow waters and produce a significant amount of natural gas and oil. Our acreage in the Piceance Basin of northwestern Colorado, a sedimentary basin in one of the country s most prolific natural gas producing regions, is substantially undeveloped. We intend to manage our investments in the Gulf of Mexico and the Piceance Basin area to maximize returns without increasing future capital expenditures significantly.

We also own natural gas and oil interests in West Texas other than the WTO, including our tertiary oil recovery operations. In addition, we own interests in properties in the Arkoma and Anadarko Basins and other non-strategic areas that are primarily operated by third-parties.

Drilling and Oil Field Services

We drill onshore for our own interests through our drilling and oil field services subsidiary, Lariat Services, Inc. (Lariat Services). We also drill wells for other natural gas and oil companies, primarily in West Texas. We own or operate a total of 38 operational rigs, including eleven operational rigs owned by Larclay, L.P. (Larclay), a joint venture with Clayton Williams Energy, Inc. (CWEI). We also own three rigs that are currently being retrofitted. Our rig fleet is designed to drill in our specific areas of operation in West Texas and the WTO. The rigs average in excess of 800 horsepower and have an average depth capacity greater than 10,500 feet.

Our oil field services divisions provide services that complement our exploration and production operations. These services include location and road construction, trucking, roustabout services, pulling units, coiled tubing units, rental tools and air drilling equipment. These services are primarily used for our own account, however, some of our service divisions also perform work for third parties. We also provide under-balanced drilling systems services for our own account.

Midstream Gas Services and Other Operations

To complement our exploration and production operations, particularly in the Piñon Field and surrounding areas, we provide gathering, compression, processing and treating services of natural gas. We have a 100%

interest in and operate the Pike s Peak gas treatment plant in West Texas and a 50% interest in the partnership that leases and operates the Grey Ranch gas treatment plant located in the WTO. The Pike s Peak and Grey Ranch gas treatment plants have capacity of 58 Mmcf per day and 82 Mmcf per day of high CO_2 gas, respectively. These two gas treatment plants, along with two third-party plants in this area, serve as the primary source of CO_2 for our current and planned tertiary oil recovery operations. We also operate or own approximately 300 miles of West Texas natural gas gathering pipelines. At September 30, 2007 we operated or owned approximately 39,200 horsepower of gas compression.

In order to ensure sufficient capacity for our existing and future Piñon Field production, we installed an additional 13,400 horsepower of compression and approximately 20 miles of large diameter pipeline in 2007.

Additionally, with our anticipated increase of high CO_2 gas production from the WTO over the next several years, we intend to build supplemental treating capacity, pipeline gathering infrastructure and compression facilities to accommodate our aggressive growth plans.

Our CO_2 gathering and tertiary oil recovery operations are conducted through our subsidiary, PetroSource Energy Company, L.P. (PetroSource). PetroSource is the sole gatherer of CO_2 from the four natural gas treatment plants located in the WTO. PetroSource owns 231 miles of CO_2 pipelines in West Texas with approximately 92,000 horsepower of owned and leased CO_2 compression. CO_2 injection has proven to be ideal in recovering additional oil that remains after traditional water flooding has been completed. We have interests in four current or potential CO_2 flood tertiary oil recovery projects in the West Texas region, the Wellman Unit, the George Allen Unit, the South Mallet Unit and the Jones Ranch area. We believe we have a competitive advantage in identifying, acquiring and developing these properties because of our strong expertise and available CO_2 supply.

Initial Public Offering

On November 9, 2007, we completed the initial public offering of our common stock. We sold 28,700,000 shares of our common stock, including 4,170,000 shares sold directly to an entity controlled by Tom L. Ward. The shares were sold at a price of $26 per share. We received net proceeds of approximately $705.4 million after deducting underwriting discounts of approximately $38.3 million and estimated offering expenses of approximately $2.5 million net. In conjunction with the offering, we granted the underwriters an option to purchase 3,679,500 additional shares of our common stock, which was exercised in full. After deducting underwriting discounts of approximately $5.7 million, we received net proceeds of approximately $89.9 million from these additional shares. The aggregate net proceeds of approximately $795.3 million were utilized as follows (in millions):

Repayment of outstanding balance on senior credit facility	$ 515.9
Repayment of note payable and accrued interest incurred in connection with recent acquisition	49.1
Excess cash to fund future capital expenditures	230.3
Total	$ 795.3

Risk Factors

Investing in our common stock involves risks, including, without limitation:

- natural gas and oil prices are volatile, and a decline in natural gas and oil prices can significantly affect our financial results and impede our growth;
- our estimated reserves are based on many assumptions that may turn out to be inaccurate, and any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves;
- unless we replace our natural gas and oil reserves, our reserves and production will decline, which would adversely affect our business, financial condition and results of operations;
- our potential drilling location inventories are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling;
- the development of the proved undeveloped reserves in the WTO may take longer and may require higher levels of capital expenditures than we currently anticipate;
- a significant portion of our operations are located in the WTO, making us vulnerable to risks associated with operating in one major geographic area;
- we have a substantial amount of indebtedness, which may adversely affect our cash flow and our ability to operate our business; and
- certain stockholders shares are restricted from immediate resale but may be sold into the market in the near future, which could cause the market price of our common stock to drop significantly.

Our Offices

Our company was founded in 1984 and is incorporated in Delaware. Our principal executive offices are located at 1601 N.W. Expressway, Suite 1600, Oklahoma City, Oklahoma 73118, and our telephone number at that address is (405) 753-5500.

The Offering

Common stock offered by the selling stockholders(1)	7,930,369 shares
Common stock outstanding(2)	141,845,661 shares
Common Stock to be outstanding assuming the conversion of our convertible preferred stock	164,121,472 shares
Dividend policy	We do not anticipate that we will pay cash dividends in the foreseeable future.
Use of Proceeds	We will not receive any proceeds from the sale of the shares of common stock by the selling stockholders.
New York Stock Exchange Symbol	SD

(1) See Selling Stockholders for information on the selling stockholders.

(2) As of November 30, 2007. The shares exclude 22,275,871 shares issuable upon conversion of our convertible preferred stock and the exercise of all warrants for convertible preferred stock.

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Summary Consolidated Historical and Pro Forma Combined Financial Data

Set forth below is our summary consolidated historical and unaudited pro forma combined financial data for the periods indicated. The historical financial data for the periods ended December 31, 2004, 2005 and 2006 and the balance sheet data as of December 31, 2005 and 2006 have been derived from our audited financial statements. Our historical financial data as of September 30, 2007 and for the nine months ended September 30, 2006 and 2007 are derived from our unaudited financial statements and, in our opinion, have been prepared on the same basis as the audited financial statements and include all adjustments, consisting of normal recurring adjustments, necessary for a fair statement of this information. The pro forma financial data have been derived from our unaudited pro forma financial statements included in this prospectus, which give pro forma effect to the transactions described in Unaudited Pro Forma Condensed Combined Financial Statements. You should read the following summary financial data in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and our historical and pro forma financial statements and related notes thereto appearing elsewhere in this prospectus.

	Historical					Pro Forma	
	Years Ended December 31,			Nine Months Ended September 30,		Nine Months Ended September 30,	Year Ended December 31,
	2004(1)	2005	2006	2006	2007	2006	2006
	(In thousands)						
Statement of Operations Data:							
Revenues	$ 175,995	$ 287,693	$ 388,242	$ 263,177	$ 461,775	$ 439,557	$ 565,256
Expenses:							
Production	10,230	16,195	35,149	21,625	77,707	64,009	84,895
Production taxes	2,497	3,158	4,654	2,579	12,328	2,579	9,770
Drilling and services	26,442	52,122	98,436	72,670	30,935	56,556	77,453
Midstream and marketing	96,180	141,372	115,076	85,525	61,191	44,307	66,848
Depreciation, depletion and amortization natural gas and crude oil	4,909	9,313	26,321	13,932	115,876	174,101	217,013
Depreciation, depletion and amortization other	7,765	14,893	29,305	22,106	36,545	22,106	29,701
General and administrative	6,554	11,908	55,634	32,024	45,781	38,126	67,629
Loss (gain) on derivative contracts	878	4,132	(12,291)	(16,176)	(55,228)	(107,039)	(111,998)
Loss (gain) on sale of assets	(210)	547	(1,023)	(849)	(1,704)	(851)	(1,023)

Total expenses	155,245	253,640	351,261	233,436	323,431	293,894	440,288
Income from operations	20,750	34,053	36,981	29,741	138,344	145,663	124,968
Other income (expense):							
Interest income	56	206	1,109	448	4,201	5,236	5,984
Interest expense	(1,678)	(5,277)	(16,904)	(4,090)	(88,630)	(59,774)	(74,056)
Minority interest	(262)	(737)	(296)	(281)	(321)	(170)	(185)
Income (loss) from equity investments	(36)	(384)	967	40	3,399	40	967
Total other income (expense)	(1,920)	(6,192)	(15,124)	(3,883)	(81,351)	(54,668)	(67,290)
Income before income taxes	18,830	27,861	21,857	25,858	56,993	90,995	57,678
Income tax expense	6,433	9,968	6,236	6,931	21,002	33,668	21,341
Income from continuing operations	12,397	17,893	15,621	18,927	35,991	57,327	36,337
Income from discontinued operations, net of tax	451	229					
Extraordinary gain	12,544						
Net income	25,392	18,122	15,621	18,927	35,991	57,327	36,337
Preferred stock dividends and accretion			3,967		30,573	27,155	40,174
Income (loss) available (applicable) to common stockholders	$ 25,392	$ 18,122	$ 11,654	$ 18,927	$ 5,418	$ 30,172	$ (3,837)

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	Historical					Pro Forma	
	Years Ended December 31,			Nine Months Ended September 30,		Nine Months Ended September 30,	Year Ended December 31,
	2004(1)	2005	2006	2006	2007	2006	2006
	(In thousands except per share data)						
Earnings Per Share Information:							
Basic							
Income from continuing operations	$ 0.22	$ 0.31	$ 0.21	$ 0.26	$ 0.35	$ 0.47	$ 0.30
Income from discontinued operations, net of income tax	0.01	0.01					
Extraordinary gain on acquisition	0.22						
Preferred stock dividends			(0.05)		(0.30)	(0.22)	(0.33)
Income (loss) per share available (applicable) to common stockholders	$ 0.45	$ 0.32	$ 0.16	$ 0.26	$ 0.05	$ 0.25	$ (0.03)
Weighted average number of shares outstanding(2):	56,312	56,559	73,727	71,692	102,562	122,429	122,426
Diluted							
Income from continuing operations	$ 0.22	$ 0.31	$ 0.21	$ 0.26	$ 0.35	$ 0.47	$ 0.30
Income from discontinued operations, net of income tax	0.01	0.01					
Extraordinary gain on acquisition	0.22						
Preferred stock dividends			(0.05)		(0.30)	(0.22)	(0.33)
Income (loss) per share available (applicable) to common stockholders	$ 0.45	$ 0.32	$ 0.16	$ 0.26	$ 0.05	$ 0.25	$ (0.03)

Weighted average number of outstanding shares(2):	56,312	56,737	74,664	72,633	103,778	123,370	123,363

(1) We recognized an extraordinary gain from the recognition of the excess of fair value over acquisition cost of $12.5 million related to an acquisition we made in 2004.

(2) The number of shares has been adjusted to reflect a 281.552-to-1 stock split in December 2005.

	Historical		
	At December 31,		At September 30,
	2005	2006	2007
	(In thousands)		
Balance Sheet Data:			
Cash and cash equivalents	$ 45,731	$ 38,948	$ 32,013
Property, plant and equipment, net	$ 337,881	$ 2,134,718	$ 2,889,495
Total assets	$ 458,683	$ 2,388,384	$ 3,170,456
Long-term debt	$ 43,133	$ 1,066,831	$ 1,451,504
Redeemable convertible preferred stock	$	$ 439,643	$ 450,356
Total stockholders equity	$ 289,002	$ 649,818	$ 965,123
Total liabilities and stockholders equity	$ 458,683	$ 2,388,384	$ 3,170,456

Summary Historical Operating and Reserve Data

The following historical estimates of net proved natural gas and oil reserves are based on reserve reports dated December 31, 2005 and 2006 and June 30, 2007, substantially all of which were prepared by our independent petroleum engineers. You should refer to Risk Factors, Management s Discussion and Analysis of Financial Condition and Results of Operations, and Business Exploration and Production in evaluating the material presented below.

	At December 31, 2005	At December 31, 2006	At June 30, 2007
Estimated Proved Reserves(1)			
Natural Gas (Bcf)(2)	237.4	850.7	967.6
Oil (MmBbls)	10.4	25.2	34.4
Total (Bcfe)	300.0	1,001.8	1,174.0
PV-10 (in millions)	$ 733.3(3)	$ 1,734.3(3)	$ 2,558.8(3)
Standardized Measure of Discounted Net Cash Flows (in millions)(4)	$ 499.2	$ 1,440.2	n/a(5)

(1) Our estimated proved reserves and the future net revenues, PV-10, and Standardized Measure of Discounted Net Cash Flows were determined using end of the period prices for natural gas and oil that we realized as of December 31, 2005, December 31, 2006 and June 30, 2007, which were $8.40 per Mcf of natural gas and $54.04 per barrel of oil at December 31, 2005, $5.64 per Mcf of natural gas and $57.75 per barrel of oil at December 31, 2006 and $6.70 per Mcf of natural gas and $63.78 per barrel of oil at June 30, 2007.

(2) Given the nature of our natural gas reserves, a significant amount of our production, primarily in the WTO, contains natural gas high in CO_2 content. These figures are net of volumes of CO_2 in excess of pipeline quality specifications.

(3) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved natural gas and oil reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash flows and using pricing assumptions in effect at the end of the period. PV-10 differs from Standardized Measure of Discounted Net Cash Flows because it does not include the effects of income taxes and other items on future net revenues. Neither PV-10 nor Standardized Measure represent an estimate of fair market value of our natural gas and oil properties. PV-10 is used by the industry and by our management as an arbitrary reserve asset value measure to compare against past reserve bases and the reserve bases of other business entities that are not dependent on the taxpaying status of the entity.

The following table provides a reconciliation of our Standardized Measure to PV-10:

	At December 31, 2005	At December 31, 2006
	(In millions)	
Standardized Measure of Discounted Net Cash Flows	$ 499.2	$ 1,440.2

Present value of future income tax and other discounted at 10%		234.1		294.1
PV-10	$	733.3	$	1,734.3

(4) The Standardized Measure of Discounted Net Cash Flows represents the present value of estimated future cash inflows from proved natural gas and oil reserves, less future development and production costs, and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized Measure differs from PV-10 because Standardized Measure includes the effect of future income taxes and other items.

(5) Standardized Measure of Discounted Net Cash Flows is only calculated at fiscal year end under applicable accounting rules.

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The following tables set forth information regarding our net production of oil, natural gas and natural gas liquids and certain price and cost information for each of the periods indicated. Because of the relatively high volumes of CO_2 produced with natural gas in certain areas of the WTO, our reported sales and reserves volumes and the related unit prices received for natural gas in these areas are reported net of CO_2 volumes stripped at the gas plants. The gas plant fees for removing CO_2 from our high CO_2 natural gas in the WTO have been taken into account in our lease operating expenses as processing and gathering fees. In all areas, natural gas sales are delivered to sales points with CO_2 levels within pipeline specifications and thus are included in sales and reserves volumes.

	Year Ended December 31,			Nine Months Ended September 30,	
	2004	2005	2006	2006	2007
Production Data:					
Natural Gas (Mmcf)	6,708	6,873	13,410	6,856	35,148
Oil (MBbls)	37	72	322	70	1,441
Combined Equivalent Volumes (Mmcfe)	6,930	7,305	15,342	7,275	43,793
Average Daily Combined Equivalent Volumes (Mmcfe/d)	18.9	20.0	42.0	27	160

	Year Ended December 31,			Nine Months Ended September 30,	
	2004	2005	2006	2006	2007
Average Prices(1):					
Natural Gas (per Mcf)	$ 4.43	$ 6.54	$ 6.19	$ 6.14	$ 6.56
Oil (per Bbl)	$ 34.03	$ 48.19	$ 56.61	$ 61.89	$ 61.67
Combined Equivalent (per Mcfe)	$ 4.47	$ 6.63	$ 6.60	$ 6.38	$ 7.30

(1) Reported prices represent actual prices for the periods presented and do not give effect to hedging transactions.

	Year Ended December 31,			Nine Months Ended September 30,	
	2004	2005	2006	2006	2007
Expenses per Mcfe:					
Lease operating expenses:					
Transportation	$ 0.14	$ 0.16	$ 0.22	$ 0.14	$ 0.15
Processing and gathering(1)	0.39	0.42	0.37	0.33	0.30
Other lease operating expenses	0.94	1.64	1.70	2.50	1.32
Total lease operating expenses	$ 1.48	$ 2.22	$ 2.29	$ 2.97	$ 1.77

Production taxes	$ 0.36	$ 0.43	$ 0.30	$ .35	$ .28

(1) Includes costs attributable to gas treatment to remove CO_2 and other impurities from our high CO_2 natural gas.

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RISK FACTORS

An investment in our common stock involves a high degree of risk. You should carefully consider the following risks and all of the other information contained in this prospectus before deciding to invest in our common stock.

Risks Related to the Natural Gas and Oil Industry and Our Business

Natural gas and oil prices are volatile, and a decline in natural gas and oil prices can significantly affect our financial results and impede our growth.

Our revenue, profitability and cash flow depend upon the prices and demand for natural gas and oil. The markets for these commodities are very volatile. Even relatively modest drops in prices can significantly affect our financial results and impede our growth. Changes in natural gas and oil prices have a significant impact on the value of our reserves and on our cash flow. Prices for natural gas and oil may fluctuate widely in response to relatively minor changes in the supply of and demand for natural gas and oil and a variety of additional factors that are beyond our control, such as:

- the domestic and foreign supply of natural gas and oil;
- the price of foreign imports;
- worldwide economic conditions;
- political and economic conditions in oil producing countries, including the Middle East and South America;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the level of consumer product demand;
- weather conditions;
- technological advances affecting energy consumption;
- availability of pipeline infrastructure, treating, transportation and refining capacity;
- domestic and foreign governmental regulations and taxes; and
- the price and availability of alternative fuels.

Lower natural gas and oil prices may not only decrease our revenues on a per share basis, but also may reduce the amount of natural gas and oil that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating natural gas and oil reserves is complex and inherently imprecise. It requires interpretations of available technical data and many assumptions, including assumptions relating to production rates and economic factors such as natural gas and oil prices, drilling and operating expenses, capital expenditures and availability of funds. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this prospectus. See Business Our Business and Primary Operations for information about our natural gas and oil reserves.

Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this prospectus. In addition, we may adjust estimates of proved reserves to reflect production history, results

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of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond our control.

The present value of future net cash flows from our proved reserves will not necessarily be the same as the current market value of our estimated natural gas and oil reserves.

We base the estimated discounted future net cash flows from our proved reserves on prices and costs in effect on the day of estimate. Actual future net cash flows from our natural gas and oil properties also will be affected by factors such as:

- actual prices we receive for natural gas and oil;
- actual cost of development and production expenditures;
- the amount and timing of actual production;
- supply of and demand for natural gas and oil; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of natural gas and oil properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

Unless we replace our natural gas and oil reserves, our reserves and production will decline, which would adversely affect our business, financial condition and results of operations.

Our future natural gas and oil reserves and production, and therefore our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs.

Our potential drilling location inventories are scheduled over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

As of June 30, 2007, only 699 of our 4,573 identified potential future well locations were attributable to proved undeveloped reserves. These potential drilling locations, including those without proved undeveloped reserves, represent a significant part of our growth strategy. Our ability to drill and develop these locations is subject to a number of uncertainties, including the availability of capital, seasonal conditions, regulatory approvals, natural gas and oil prices, costs and drilling results. Because of these uncertainties, we do not know if the numerous potential drilling locations we have will ever be drilled or if we will be able to produce natural gas or oil from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from our current expectations, which could adversely affect our business.

We will not know conclusively prior to drilling whether natural gas or oil will be present in sufficient quantities to be economically viable.

We describe some of our current prospects and drilling locations and our plans to explore those prospects and drilling locations in this prospectus. A prospect is a property on which we have identified what our geoscientists believe, based on available seismic and geological information, to be indications of natural gas or oil. Our prospects and drilling locations are in various stages of evaluation, ranging from a prospect that is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. Even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon bearing formation

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or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from the well or abandonment of the well. From January 1, 2007 through September 30, 2007, we participated in drilling a total of 189 gross wells, of which six have been identified as a dry hole. If we drill additional wells that we identify as dry holes in our current and future prospects, our drilling success rate may decline and materially harm our business. In sum, the cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive.

Properties that we buy may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against them.

Our reviews of properties we acquire are inherently incomplete because it generally is not feasible to review in depth every individual property involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as soil or ground water contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, we often assume certain environmental and other risks and liabilities in connection with acquired properties, which risks and liabilities could have a material adverse effect on our results of operations and financial condition.

The development of the proved undeveloped reserves in the WTO and other areas of operation may take longer and may require higher levels of capital expenditures than we currently anticipate.

Approximately 66% of the estimated proved reserves that we own or have under lease in the WTO as of June 30, 2007 are proved undeveloped reserves and 62% of our total reserves are proved undeveloped reserves. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Therefore, ultimate recoveries from these fields may not match current expectations. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves.

A significant portion of our operations are located in WTO, making us vulnerable to risks associated with operating in one major geographic area.

As of June 30, 2007, approximately 55% of our proved reserves and approximately 40% of our production were located in the WTO. In addition, a substantial portion of our WTO natural gas contains a high concentration of CO_2 and requires treating. As a result, we may be disproportionately exposed to the impact of delays or interruptions of production from these wells caused by transportation and treatment capacity constraints, curtailment of production or treatment plant closures for scheduled maintenance or unanticipated occurrences.

Many of our prospects in the WTO may contain natural gas that is high in CO_2 content, which can negatively affect our economics.

The reservoirs of many of our prospects in the WTO may contain natural gas that is high in CO_2 content. The natural gas produced from these reservoirs must be treated for the removal of CO_2 prior to marketing. If we cannot obtain sufficient capacity at treatment facilities for our natural gas with a high CO_2 concentration, or if the cost to obtain such capacity significantly increases, we could be forced to delay production and development or experience increased production costs.

Furthermore, when we treat the gas for the removal of CO_2, some of the methane is used to run the treatment plant as fuel gas and other methane and heavier hydrocarbons, such as ethane, propane and butane, cannot be separated from the CO_2 and is lost. This is known as plant shrink. Historically our plant shrink has been approximately 14% in the WTO. We do not know the amount of CO_2 we will encounter in any well until it is drilled. As a result, sometimes we encounter CO_2 levels in our wells that are higher than expected. The amount of CO_2 in the gas produced affects the heating content of the gas. For example, if a well is 65% CO_2, the gas produced often has a heating content of between 300 and 350 MBtu per Mcf. Giving consideration for plant shrink, as many as four Mcf of high CO_2 gas must be produced to sell one MmBtu of natural gas. We report our volumes of natural gas reserves and production net of CO_2 volumes that are removed prior to sales. Since the treatment expenses are incurred on an Mcf basis, we will incur a higher effective treating cost per MmBtu of natural gas sold for natural gas with a higher CO_2 content. As a result, high CO_2 gas wells must produce at much higher rates than low CO_2 gas wells to be economic, especially in a low natural gas price environment.

We may experience difficulty in staffing and retaining employees on our new drilling rigs, which may adversely affect the efficiency of our drilling program.

We have increased our number of drilling rigs and the level of our activity substantially. This has required us to add additional employees to staff our drilling rigs and to add professional and support staff to other departments. If we are unable to retain these employees, we may experience decreased efficiency and delays in our drilling program.

A significant decrease in natural gas production in our areas of midstream gas services operation, due to the decline in production from existing wells, depressed commodity prices or otherwise, would adversely affect our revenues and cash flow for our midstream gas services segment.

The profitability of our midstream business is materially impacted by the volume of natural gas we gather, transmit and process at our facilities. Most of the reserves backing up our midstream assets are operated by our exploration and production segment. A material decrease in natural gas production in our areas of operation would result in a decline in the volume of natural gas delivered to our pipelines and facilities for gathering, transmitting and processing. The effect of such a material decrease would be to reduce our revenues, operating income and cash flows. Fluctuations in energy prices can greatly affect production rates and investments by our exploration and production business and third-parties in the development of new natural gas and oil reserves. Drilling activity generally decreases as natural gas and oil prices decrease. We have no control over factors affecting production activity, including prevailing and projected energy prices, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulation and the availability and cost of capital. Failure to connect new wells to our gathering systems would, therefore, result in the amount of natural gas we gather, transmit and process being reduced substantially over time and could, upon exhaustion of the current wells, cause us to abandon our gathering systems and, possibly cease gathering, transmission and processing operations. Our ability to connect to new wells will be dependent on the level of drilling activity in our areas of operations and competitive market factors. As a consequence of these declines, our revenues and cash flows could be materially adversely affected.

Our use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of natural gas and oil, which could adversely affect the results of our drilling operations.

A significant aspect of our exploration and development plan involves seismic data. Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are present in those structures. Other geologists and petroleum professionals, when studying the same seismic data, may have significantly different interpretations than our professionals. In addition, the use of 2-D and 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses due to such expenditures. As a result, our drilling activities may not be geologically successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area may not improve.

We often gather 2-D and 3-D seismic data over large areas. Our interpretation of seismic data delineates for us those portions of an area that we believe are desirable for drilling. Therefore, we may choose not to acquire option or lease rights prior to acquiring seismic data, and in many cases, we may identify hydrocarbon indicators before seeking option or lease rights in the location. If we are not able to lease those locations on acceptable terms, it would result in our having made substantial expenditures to acquire and analyze 2-D and 3-D data without having an opportunity to attempt to benefit from those expenditures.

Drilling for and producing natural gas and oil are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our drilling and operating activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for natural gas and oil can be unprofitable, not only from dry holes, but from productive wells that do not produce sufficient revenues to return a profit. In addition, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- unusual or unexpected geological formations and miscalculations;
- pressures;
- fires;
- blowouts;
- loss of drilling fluid circulation;
- title problems;
- facility or equipment malfunctions;
- unexpected operational events;
- shortages of skilled personnel;
- shortages or delivery delays of equipment and services;
- compliance with environmental and other regulatory requirements; and
- adverse weather conditions.

Any of these risks can cause substantial losses, including personal injury or loss of life; damage to or destruction of property, natural resources and equipment; pollution; environmental contamination or loss of wells; and regulatory fines or penalties.

Insurance against all operational risks is not available to us. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. We do not carry environmental insurance, thus, losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not covered in full or in part by insurance could have a material adverse impact on our business activities, financial condition and results of operations.

Market conditions or operational impediments may hinder our access to natural gas and oil markets or delay our production.

Market conditions or a lack of satisfactory natural gas and oil transportation arrangements may hinder our access to natural gas and oil markets or delay our production. The availability of a ready market for our natural gas and oil production depends on a number of factors, including the demand for and supply of natural gas and oil and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities. For example, we are currently experiencing capacity limitations in the Piñon Field. Our failure to obtain such services on acceptable terms or expand our midstream assets could materially harm our business. We may be required to shut in wells for a lack of a market or because access to natural gas pipelines, gathering system capacity or processing facilities may be limited or unavailable. If that were to occur, then we would be unable to realize revenue from those wells until production arrangements were made to deliver the production to market.

Our development and exploration operations require substantial capital and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our natural gas and oil reserves.

The natural gas and oil industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration, development, production and acquisition of natural gas and oil reserves. To date, we have financed capital expenditures primarily with proceeds from the sale of equity, bank borrowings and cash generated by operations. We intend to finance our future capital expenditures with the sale of equity, asset sales, cash flow from operations and current and new financing arrangements. Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of natural gas and oil we are able to produce from existing wells;
- the prices at which natural gas and oil are sold; and
- our ability to acquire, locate and produce new reserves.

If our revenues decrease as a result of lower natural gas and oil prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. In order to fund our capital expenditures, we must seek additional financing. Our senior credit facility and term loan contain covenants restricting our ability to incur additional indebtedness without the consent of the lenders. Our lenders may withhold this consent in their sole discretion.

In addition, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. The failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our natural gas and oil reserves.

We have a substantial amount of indebtedness, which may adversely affect our cash flow and our ability to operate our business.

As of September 30, 2007, our total indebtedness was $1.5 billion, which represented approximately 51% of our total capitalization. Our substantial level of indebtedness increases the possibility that we may be unable to generate cash sufficient to pay, when due, the principal of, interest on or other amounts due in respect of our indebtedness. Our substantial indebtedness, combined with our lease and other financial obligations and contractual commitments, could have other important consequences to you. For example, it could:

- make us more vulnerable to adverse changes in general economic, industry and competitive conditions and adverse changes in government regulation;
- require us to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness, thereby reducing the availability of our cash flows to fund working capital, capital expenditures, acquisitions and other general corporate purposes;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;

place us at a competitive disadvantage compared to our competitors that are less leveraged and, therefore, may be able to take advantage of opportunities that our leverage prevents us from pursuing; and

limit our ability to borrow additional amounts for working capital, capital expenditures, acquisitions, debt service requirements, execution of our business strategy or other purposes.

Any of the above listed factors could materially adversely affect our business, financial condition and results of operations.

Our senior credit facility and term loan have restrictions and financial covenants which could adversely affect our operations.

We will depend on our senior credit facility for a portion of future capital needs. The senior credit facility and term loan restrict our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations. We also are required to comply with certain financial covenants and ratios. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control. Our failure to comply with any of the restrictions and covenants under the senior credit facility, term loan or other debt financing could result in a default under those facilities, which could cause all of our existing indebtedness to be immediately due and payable.

The senior credit facility limits the amounts we can borrow to a borrowing base amount, determined by the lender in its sole discretion on a semi-annual basis, based upon projected revenues from the natural gas and oil properties securing our loan. The lender can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under the senior credit facility, and any increase in the borrowing base requires its consent. Outstanding borrowings in excess of the borrowing base must be repaid immediately, or we must pledge other natural gas and oil properties as additional collateral. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under the senior credit facility.

Our derivative activities could result in financial losses or could reduce our earnings.

To achieve a more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of natural gas and oil, we currently, and may in the future, enter into derivative instruments for a portion of our natural gas and oil production, including collars and price-fix swaps. We have not designated any of our derivative instruments as hedges for accounting purposes and record all derivative instruments on our balance sheet at fair value. Changes in the fair value of our derivative instruments are recognized in current earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments. Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- production is less than expected;
- the counter-party to the derivative instrument defaults on its contract obligations; or
- there is a change in the expected differential between the underlying price in the derivative instrument and actual prices received.

In addition, these types of derivative arrangements limit the benefit we would receive from increases in the prices for natural gas and oil and may expose us to cash margin requirements.

Competition in the natural gas and oil industry is intense, which may adversely affect our ability to succeed.

The natural gas and oil industry is intensely competitive, and we compete with companies that have greater resources. Many of these companies not only explore for and produce natural gas and oil, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive natural gas and oil properties and exploratory prospects or identify, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low natural gas and oil market prices. Our larger competitors may be able to absorb the burden of present and future federal, state, local and other laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing natural gas and oil properties.

Downturns in natural gas and oil prices can result in decreased oil field activity which, in turn, can result in an oversupply of service providers and drilling rigs. This oversupply can result in severe reductions in prices received for oil field services or a complete lack of work for crews and equipment.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations.

Our natural gas and oil exploration, production, transportation and treatment operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. For instance, we may be unable to obtain all necessary permits, approvals and certificates for proposed projects. Alternatively, we may have to incur substantial expenditures to obtain, maintain or renew authorizations to conduct existing projects. If a project is unable to function as planned due to changing requirements or public opposition, we may suffer expensive delays, extended periods of non-operation or significant loss of value in a project. All such costs may have a negative effect on our business and results of operations.

Our business is subject to federal, state and local laws and regulations as interpreted and enforced by governmental agencies and other bodies vested with much authority relating to the exploration for, and the development, production and transportation of, natural gas and oil. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on us. For instance, the U.S. Department of the Interior s Minerals Management Service (MMS), may suspend or terminate our operations on federal leases for failure to pay royalties or comply with safety and environmental regulations.

Our operations expose us to potentially substantial costs and liabilities with respect to environmental, health and safety matters.

We may incur substantial costs and liabilities as a result of environmental, health and safety requirements applicable to our natural gas and oil exploration, development, production, transportation, treatment, and other activities. These costs and liabilities could arise under a wide range of environmental, health and safety laws, that cover, among other things, emissions into the air and water, habitat and endangered species protection, the containment and disposal of hazardous substances, oil field waste and other waste materials, the use of underground injection wells, and wetlands protection. These laws and regulations are complex, change frequently and have tended to become increasingly strict over time. Failure to comply with environmental, health and safety laws or regulations may result in assessment of administrative, civil, and criminal penalties, imposition of cleanup and site restoration costs and liens, and the issuance of orders enjoining or limiting our current or future operations. Compliance with these laws and regulations also increases the cost of our operations and may prevent or delay the commencement or continuance of a given operation. Specifically, we may incur increased expenditures in the future in order to maintain compliance with laws and regulations governing emissions of air pollutants from our natural gas treatment plants. See Business Environmental Matters and Regulation.

Under certain environmental laws that impose strict, joint and several liability we may be required to remediate our contaminated properties regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were or were not in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons, property or natural resources may result from environmental and other impacts of our operations. Moreover, new or modified environmental, health or safety laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. Therefore, the costs to comply with environmental, health or safety laws or regulations or the liabilities incurred in connection with them could significantly and adversely affect our business, financial condition or results of operations. In addition, many countries as well as several states of the U.S. have agreed to regulate emissions of greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning of natural gas and oil are greenhouse gases. Regulation of greenhouse gases could adversely impact some of our operations and demand for some of our services or products in the future. See Business Environmental Matters and Regulation.

The inability of one or more of our customers to meet their obligations may adversely affect our financial results.

Substantially all of our accounts receivable for natural gas and oil sales, drilling and oil field services and midstream gas services result from billings to third-parties in the energy industry. This concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. In addition, our natural gas and oil derivative arrangements expose us to credit risk in the event of nonperformance by counterparties.

We have identified a material weakness in our internal control over financial reporting. If additional material weaknesses are detected or if we fail to maintain an adequate system of internal control over financial reporting this could adversely affect our ability to accurately report our results.

We are not currently required to comply with Section 404 of the Sarbanes Oxley Act of 2002, and are therefore not required to make an assessment of the effectiveness of our internal controls over financial reporting for that purpose. As disclosed elsewhere in this prospectus and in Note 1 to our consolidated financial statements included in this prospectus, we have restated our consolidated financial statements for our December 31, 2006 year end. We have considered the internal control over financial reporting implications of the error which resulted in the restatement of our consolidated financial statements and determined a material weakness existed as it relates to financial reporting process and accounting for derivatives. See Management s Discussion and Analysis of Financial Condition and Results of Operations Restatement of Previously Issued Financial Statements Correction of an Accounting Error.

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with generally accepted accounting principles. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis.

Effective internal controls are necessary for us to provide reliable financial reports and effectively prevent fraud. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. Our efforts to develop and maintain our internal controls may not be successful, and we may be unable to maintain adequate controls over our financial processes and reporting in the future, including future compliance with the obligations under Section 404 of the Sarbanes-Oxley Act of 2002. We will be required to comply with Section 404 of the Sarbanes-Oxley Act of 2002 effective as of December 31, 2008. Any failure to develop or maintain effective controls, or difficulties encountered in their implementation or other effective improvement of our internal controls could harm our operating results. Ineffective internal controls could also cause investors to lose confidence in our reported financial information.

Risks Related to Our Common Stock

A significant portion of our outstanding shares of common stock may be sold into the market in the near future. This could cause the market price of our common stock to drop significantly.

As of November 30, 2007, we had outstanding 141,845,661 shares of common stock. In addition, 22,275,871 shares of common stock will be issuable upon conversion of our outstanding convertible preferred stock. Of these shares, the 7,930,369 shares the selling stockholders are selling in this offering will be freely tradable without restriction under the Securities Act except for any shares purchased by one of our affiliates as defined in Rule 144 under the Securities Act.

The resale of these shares in the future could cause the market price of our stock to drop significantly.

The market price for shares of our common stock may be highly volatile and could be subject to wide fluctuations.

The market price for shares of our common stock may be highly volatile and could be subject to wide fluctuations, even if an active trading market develops. Some of the factors that could negatively affect our share price include:

- actual or anticipated variations in our reserve estimates and quarterly operating results;
- liquidity and the registration of our common stock for public resale;
- sales of our common stock by our stockholders;
- changes in natural gas and oil prices;
- changes in our cash flows from operations or earnings estimates;
- publication of research reports about us or the exploration and production industry generally;
- increases in market interest rates which may increase our cost of capital;
- changes in applicable laws or regulations, court rulings and enforcement and legal actions;
- changes in market valuations of similar companies;
- adverse market reaction to any increased indebtedness we incur in the future;
- additions or departures of key management personnel;
- actions by our stockholders;
- speculation in the press or investment community regarding our business;
- large volume of sellers of our common stock pursuant to our resale registration statement with a relatively small volume of purchasers;
- general market and economic conditions; and
- domestic and international economic, legal and regulatory factors unrelated to our performance.

We do not anticipate paying any dividends on our common stock in the foreseeable future.

We do not expect to declare or pay any cash or other dividends in the foreseeable future on our common stock, as we intend to use cash flow generated by operations to expand our business. Our senior credit facility and term loan restrict our ability to pay cash dividends on our common stock, and we may also enter into credit agreements or other borrowing arrangements in the future that restrict our ability to declare or pay cash dividends on our common stock. In addition, the certificate of designation for our convertible preferred stock prohibits the payment of dividends to holders of our common stock without the consent of holders of a majority of our outstanding convertible preferred stock.

You may experience dilution of your ownership interests due to the future issuance of additional shares of our common stock.

We may in the future issue our previously authorized and unissued securities, resulting in the dilution of the ownership interests of our present stockholders and purchasers of common stock offered hereby. As of September 30, 2007, we were authorized to issue 400 million shares of common stock and 50 million shares of preferred stock with preferences and rights as determined by our Board of Directors. As of November 30, 2007, we had 141,854,661 shares of common stock outstanding and pursuant to our stock incentive plan, we have also reserved approximately 2.2 million shares of our common stock for future issuance as restricted stock, stock options or other equity-based grants to employees and directors. We may also issue additional shares of our common stock or other securities that are convertible into or exercisable for common stock in connection with the hiring of personnel, future acquisitions, future private placements of our securities for

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capital raising purposes or for other business purposes. We have 2,184,287 shares of convertible preferred stock outstanding, which may be converted into 22,275,871 shares of common stock at any time by the holders of such preferred stock or by us at any time following May 7, 2008 upon satisfaction of other conditions. See Description of Capital Stock Preferred Stock Convertible Preferred Stock. The potential issuance or sale of additional shares of common stock may create downward pressure on the trading price of our common stock.

Our certificate of incorporation and bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Our certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our certificate of incorporation and bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- a classified board of directors, so that only approximately one-third of our directors are elected each year;
- limitations on the removal of directors;
- the prohibition of stockholder action by written consent;
- and limitations on the ability of our stockholders to call special meetings and establish advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders.

Delaware law prohibits us from engaging in any business combination with any interested stockholder, meaning generally that a stockholder who beneficially owns more than 15% of our stock cannot acquire us for a period of three years from the date this person became an interested stockholder, unless various conditions are met, such as approval of the transaction by our board of directors.

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CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

Various statements contained in this prospectus, including those that express a belief, expectation, or intention, as well as those that are not statements of historical fact, are forward-looking statements. The forward-looking statements may include projections and estimates concerning the timing and success of specific projects and our future production, revenues, income and capital spending. Our forward-looking statements are generally accompanied by words such as estimate, project, predict, believe, expect, anticipate, potential, could, may, foresee, plan, goa convey the uncertainty of future events or outcomes. The forward-looking statements in this prospectus speak only as of the date of this prospectus; we disclaim any obligation to update these statements unless required by securities law, and we caution you not to rely on them unduly. We have based these forward-looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties relating to, among other matters, the risks discussed under the heading Risk Factors and the following:

- the volatility of natural gas and oil prices;
- discovery, estimation, development and replacement of natural gas and oil reserves;
- cash flow and liquidity;
- financial position;
- business strategy;
- amount, nature and timing of capital expenditures, including future development costs;
- availability and terms of capital;
- timing and amount of future production of natural gas and oil;
- availability of drilling and production equipment;
- timing of drilling rig fabrication and delivery;
- customer contracting of drilling rigs;
- availability of oil field labor;
- availability and regulation of CO_2;
- operating costs and other expenses;
- prospect development and property acquisitions;
- availability of pipeline infrastructure to transport natural gas production;
- marketing of natural gas and oil;

competition in the natural gas and oil industry;

governmental regulation and taxation of the natural gas and oil industry; and

developments in oil-producing and natural gas-producing countries.

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USE OF PROCEEDS

The selling stockholders will receive all of the proceeds from any sales of our common stock pursuant to this registration statement, and we will not receive any such proceeds. See Selling Stockholders.

DIVIDEND POLICY

We do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future. We currently intend to retain all available funds and any future earnings for use in the operation and expansion of our business, including exploration, development and acquisition activities. In addition, the terms of our revolving credit facility and term loan restrict our ability to pay dividends to holders of common stock. In addition, the certificate of designation for our convertible preferred stock prohibits the payment of dividends to holders of our common stock without the consent of holders of a majority of our outstanding convertible preferred stock. Accordingly, if our dividend policy were to change in the future, our ability to pay dividends would be subject to these restrictions and our then existing conditions, including our results of operations, financial condition, contractual obligations, capital requirements, business prospects and other factors deemed relevant by our board of directors. In December 2003, we paid a cash dividend on our common stock in the amount of $0.02 per share on the 56,312,400 shares then outstanding.

UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL STATEMENTS

The following unaudited pro forma condensed combined financial information reflects our historical results as adjusted on a pro forma basis to give effect to the NEG acquisition and other 2006 acquisitions and the related financing transactions, which were entered into in order to fund these transactions. The unaudited pro forma condensed combined statements of operations information for the year ended December 31, 2006 and the nine months ended September 30, 2006 give effect to these transactions as if they occurred on January 1, 2006. The pro forma adjustments are based on available information and assumptions that our management believes are reasonable and are described in the related notes.

NEG acquisition

We acquired all the outstanding membership interests of NEG on November 21, 2006 for approximately $990.4 million in cash, 12,842,000 shares of our common stock (valued at approximately $231.2 million) and the assumption of $300 million in debt, and received $21.1 million in available cash. The cash requirements were funded from the issuance of $550 million in preferred stock, common units and additional banking arrangements.

Prior to our acquisition of NEG, NEG acquired the remaining 50% membership interests in NEG Holding LLC that NEG did not already own, and NEG distributed all of its 50.1% capital stock and $148 million senior notes investment in National Energy Group, Inc. (NEGI). As a result, we acquired 100% of the membership interests in NEG Holding LLC and no interest in NEGI.

Other 2006 acquisitions

Our acquisition in March 2006 from a former director and former executive officer of additional equity interests in PetroSource to increase our ownership percentage from 86.5% to 99% in exchange for the extinguishment of subordinated debt of approximately $1.0 million and a $4.5 million cash payment for a total consideration of approximately $5.5 million.

Our acquisition in May 2006 of working interests in WTO leases for cash consideration of $40.9 million.

Our acquisition in May 2006 of working interests in leases in WTO for $4.7 million of common stock at $18.50 per share and cash of $8.2 million for a total consideration of $12.9 million.

Our acquisition in June 2006 from a former director and former executive officer of additional working interests in WTO leases in which we already held interests in exchange for cash consideration of $9.0 million.

Our acquisition in June 2006 of the remaining 1% equity interest in PetroSource in exchange for common stock of $0.5 million at $17.25 per share.

The historical statement of operations information for the year ended December 31, 2006 is derived from our audited consolidated financial statements. The historical statement of operations information for the nine months ended September 30, 2006 is derived from our unaudited condensed consolidated financial statements. We have provided the historical information regarding us and our subsidiaries and the assumptions and adjustments for the pro forma information.

The unaudited pro forma condensed combined financial statements are presented for informational purposes only and are not necessarily indicative of the combined results of operations which would have been realized had the transactions been effective for the period presented or the combined results of operations of SandRidge and its subsidiaries (including the entities to be acquired in the NEG acquisition) in the future. The unaudited pro forma condensed combined financial information for the period presented may have been different had the transactions actually been completed during the period due to, among other factors, those factors discussed in Risk Factors.

You should read the unaudited pro forma condensed combined financial information in conjunction with our historical financial statements and related notes and Management s Discussion and Analysis of Financial Condition and Results of Operations included in this prospectus.

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SandRidge Energy, Inc.

**UNAUDITED PRO FORMA CONDENSED COMBINED STATEMENT OF OPERATIONS
FOR THE YEAR ENDED DECEMBER 31, 2006**

	SandRidge Energy Historical	NEG Historical (January 1, 2006 through November 21, 2006)	Pro Forma Adjustments	SandRidge Energy Pro Forma Combined
	(In thousands except per share data)			
Revenues	$ 388,242	$ 253,832	$ (76,818)(a)(b)	$ 565,256
Expenses:				
Production	35,149	50,527	(781)(a)(b)	84,895
Production taxes	4,654	5,116		9,770
Drilling and services	98,436		(20,983)(a)	77,453
Midstream and marketing	115,076		(48,228)(a)	66,848
Depreciation, depletion and amortization natural gas and crude oil	25,723	91,611	99,081(a)(c)	216,415
Depreciation, depletion and amortization other	29,903	396		30,299
General and administrative cost	55,634	16,566	(4,571)(a)	67,629
Gain on derivative contracts	(12,291)	(99,707)		(111,998)
Gain on sale of assets	(1,023)			(1,023)
Income from operations	36,981	189,323	(101,336)	124,968
Interest income	1,109	4,875		5,984
Interest expense	(16,904)	(10,411)	(46,741)(d)	(74,056)
Minority interest	(296)		111(e)	(185)
Income from equity investments	967			967
Income before income tax provision	21,857	183,787	(147,966)	57,678
Income tax provision	6,236	2,143	12,962(f)	21,341
Income from continuing operations	15,621	181,644	(160,928)	36,337
Preferred dividends and accretion	3,967		36,207(g)	40,174
Income (loss) available (applicable) to common stockholders	$ 11,654	$ 181,644	$ (197,135)	$ (3,837)
Earnings per share available (applicable) to common stockholders:				
Basic	$ 0.16			$ (0.03)

Diluted	$ 0.16		$ (0.03)
Number of shares used in calculating earnings per share:			
Basic	73,727	48,699(h)(i)	122,426
Diluted	74,664	48,699(h)(i)	123,363

See Notes to Unaudited Pro Forma Condensed Combined Financial Information

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SandRidge Energy, Inc.

UNAUDITED PRO FORMA COMBINED CONSOLIDATED STATEMENTS OF OPERATIONS FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2006

	SandRidge Energy Historical	NEG Historical (January 1, 2006 through September 30, 2006)	Pro Forma Adjustments	SandRidge Energy Pro Forma Combined
Revenues	$ 263,177	$ 239,613	$ (63,233)(a)(b)	$ 439,557
Expenses				
Production	21,625	38,332	(94)(a)(b)	59,863
Production taxes	2,579	4,162		6,725
Drilling and services	72,670		(16,114)(a)	56,556
Midstream and marketing	85,525		(41,218)(a)	44,307
Depreciation, depletion and amortization natural gas and crude oil	13,932	76,189	83,649(a)(c)	173,770
Depreciation, depletion and amortization other	22,106	331		22,437
General and administrative	32,024	10,281	(4,179)(a)	38,126
Gain on derivative contracts	(16,176)	(90,863)		(107,039)
Gain on sale of assets	(849)	(2)		(851)
Income from operations	29,741	201,199	(85,277)	145,663
Interest income	448	4,788		5,236
Interest expense	(4,090)	(16,738)	(38,946)(d)	(59,774)
Minority interest	(281)		111(e)	(170)
Income from equity investments	40			40
Income before income tax provision	25,858	189,249	(124,112)	90,995
Income tax provision	6,931	2,143	24,594(f)	33,668
Income from continuing operations	18,927	187,106	(148,706)	57,327
Preferred dividend and accretion			27,155(g)	27,155
Income available to common stockholders	$ 18,927	$ 187,106	$ (175,861)	$ 30,172
Earnings per share available to common stockholders:				
Basic	$ 0.26			$ 0.25
Diluted	$ 0.26			$ 0.25

Number of shares used in calculating earnings per share:			
Basic	71,692	50,737(h)(i)	122,429
Diluted	72,633	50,737(h)(i)	123,370

See Notes to Unaudited Pro Forma Condensed Combined Financial Information

NOTES TO UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL INFORMATION

Basis of Presentation

The unaudited pro forma condensed combined statements of operations for the year ended December 31, 2006 and the nine months ended September 30, 2006 give effect to the NEG acquisition and the other 2006 acquisitions and the related financing transactions as if they occurred on January 1, 2006.

NEG s combined financial statements include the accounts of NEG and subsidiaries excluding NEGI, and the 103/4% Senior Notes due from NEGI, but including NEGI s 50% membership interest in NEG Holding LLC, from January 1, 2006 through November 21, 2006, the date of the NEG acquisition for purposes of the pro forma condensed combined statement of operations for the year ended December 31, 2006 and January 1, 2006 through September 30, 2006 for purposes of the pro forma condensed combined statement of operations for the nine months ended September 30, 2006.

The unaudited pro forma condensed combined statements of operations for the year ended December 31, 2006 and the nine months ended September 30, 2006 have been prepared based on the following information:

(a) audited consolidated financial statements of SandRidge and its subsidiaries as of and for the year ended December 31, 2006;

(b) unaudited condensed consolidated financial statements of SandRidge and its subsidiaries as of and for the nine months ended September 30, 2006; and

(c) other supplementary information we considered necessary for the purpose of reflecting the transactions contemplated in the pro forma combined financial statements.

We accounted for this acquisition using the purchase method of accounting for business combinations. Under the purchase method of accounting, we are deemed to be the acquirer for accounting purposes based on a number of factors determined in accordance with GAAP. The purchase method of accounting requires the assets we acquired and liabilities we assumed to be recorded at their estimated fair values.

For purposes of these pro forma condensed combined financial statements, the presentation of certain historical NEG financial information has been modified to conform to this pro forma presentation.

Statement of Operations Adjustments

(a) Reflects the pro forma elimination of activity between us and NEG. We provided services to NEG as the operator of certain oil and gas properties and also provided other services to NEG.

(b) Reflects the increase in revenues and expenses related to the other 2006 acquisitions of $5.2 million in revenues and $1.5 million in production expenses. These acquisitions were completed by September 30, 2006.

(c) Reflects a $97.0 million and $81.7 million incremental increase in depletion expense resulting from the step-up of property, plant and equipment acquired based on the allocation of the purchase price to the properties fair value at December 31, 2006 and September 30, 2006, respectively. Adjustment assumes no material changes in the estimated lives or amortization periods for acquired assets as a result of the purchase price allocation.

(d) Reflects adjustment to increase interest expense for the effect of the additional debt assumed from the merger and the amounts borrowed as well as to recognize amortization expense associated with our estimated debt issuance costs. The interest rate used in the calculation of interest expense is monthly LIBOR plus 4.5%, the expected actual interest rates, and the life used in the calculation of amortization expense is based on the expected life of the new debt. If the actual interest rate is 1/8% more or less than the assumed rate, the interest

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cost will increase or decrease by approximately $0.5 million for the year ended December 31, 2006 and $0.4 million for the nine months ended September 30, 2006.

(e) Reflects the net pro forma adjustment to minority interest as a result of the acquisition of additional interests in PetroSource in our financial statements.

(f) Reflects adjustment to income tax expense to reflect total combined pro forma income tax expense at a 37% statutory income tax rate as NEG was organized as a limited liability company for the period presented, thus not subject to corporate taxes.

(g) Reflects preferred dividends of 7.75% per annum and accretion on convertible preferred stock.

(h) Reflects shares issued for the NEG and other 2006 acquisitions adjusted for the inclusion of weighted average share amounts at December 31, 2006 and September 30, 2006.

Year ended December 31, 2006

Shares issued for the NEG and other 2006 acquisitions are as follows (in thousands):

NEG acquisition and related financing arrangements	18,174
Other 2006 acquisitions	279
	18,453
Less: weighted shares included in historical results	(2,134)
	16,319

Nine months ended September 30, 2006

Shares issued for the NEG and other 2006 acquisitions are as follows (in thousands):

NEG acquisition and related financing arrangements	18,174
Other 2006 acquisitions	279
	18,453
Less: weighted shares included in historical results	(96)
	18,357

(i) Reflects the issuance of 32,379,500 shares on November 9, 2007.

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SELECTED CONSOLIDATED HISTORICAL FINANCIAL DATA

Set forth below is our selected consolidated historical financial data for the periods indicated. The historical statement of operations data for the periods ended December 31, 2002, 2003, 2004, 2005 and 2006 and the balance sheet data as of December 31, 2002, 2003, 2004, 2005 and 2006 have been derived from our audited financial statements. Our historical statement of operations data as of and for the nine months ended September 30, 2006 and 2007 are derived from our unaudited financial statements and, in our opinion, have been prepared on the same basis as the audited financial statements and include all adjustments, consisting of normal recurring adjustments, necessary for a fair statement of this information. You should read the following summary financial data in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and our historical and pro forma financial statements and related notes thereto appearing elsewhere in this prospectus.

	Years Ended December 31,					Nine Months Ended September 30,	
	2002	2003(1)	2004(2)	2005	2006	2006	2007
	(In thousands)						
Statement of Operations Data:							
Revenues	$ 59,247	$ 155,337	$ 175,995	$ 287,693	$ 388,242	$ 263,177	$ 461,775
Expenses:							
Production	7,949	7,980	10,230	16,195	35,149	21,625	77,707
Production taxes	661	2,099	2,497	3,158	4,654	2,579	12,328
Drilling and services	8,858	13,847	26,442	52,122	98,436	72,670	30,935
Midstream marketing	23,689	94,620	96,180	141,372	115,076	85,525	61,191
Depreciation, depletion and amortization natural gas and crude oil	3,142	3,298	4,909	9,313	26,321	13,932	115,876
Depreciation, depletion and amortization other	2,431	5,284	7,765	14,893	29,305	22,106	36,545
General and administrative	4,355	3,705	6,554	11,908	55,634	32,024	45,781
Loss (gain) on derivative contracts	3,193	3,450	878	4,132	(12,291)	(16,176)	(55,228)
Loss (gain) on sale of assets		(1,284)	(210)	547	(1,023)	(849)	(1,704)
Total operating expenses	54,278	132,999	155,245	253,640	351,261	233,436	323,431
Income from operations	4,969	22,338	20,750	34,053	36,981	29,741	138,344

Other income (expense):							
Interest income	84	103	56	206	1,109	448	4,201
Interest expense	(1,000)	(1,208)	(1,678)	(5,277)	(16,904)	(4,090)	(88,630)
Minority interest	(673)	(96)	(262)	(737)	(296)	(281)	(321)
Income (loss) from equity investments	304	1,056	(36)	(384)	967	40	3,399
Total other income (expense)	(1,285)	(145)	(1,920)	(6,192)	(15,124)	3,883	81,351
Income before income taxes	3,684	22,193	18,830	27,861	21,857	25,858	56,993
Income tax expense	1,334	7,585	6,433	9,968	6,236	6,931	21,002
Income from continuing operations	2,350	14,608	12,397	17,893	15,621	18,927	35,991
Income (loss) from discontinued operations, net of tax	1,105	(85)	451	229			
Cumulative effect of accounting change		(1,636)					
Extraordinary gain			12,544				
Net income	3,455	12,887	25,392	18,122	15,621	18,927	35,991
Preferred stock dividends and accretion					3,967		30,573
Income (loss) available (applicable) to common stockholders	$ 3,455	$ 12,887	$ 25,392	$ 18,122	$ 11,654	$ 18,927	$ 5,418

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	Historical						
	Years Ended December 31,					Nine Months Ended September 30,	
	2002	2003(1)	2004(2)	2005	2006	2006	2007
	(In thousands except per share data)						
Earnings Per Share Information:							
Basic							
Income from continuing operations	$ 0.04	$ 0.26	$ 0.22	$ 0.31	$ 0.21	$ 0.26	$ 0.35
Income (loss) from discontinued operations, net of income tax	0.02		0.01	0.01			
Extraordinary gain on acquisition			0.22				
Cumulative effect of change in accounting principle, net of income tax		(0.03)					
Preferred stock dividends					(0.05)		(0.30)
Income per share available to common stockholders	$ 0.06	$ 0.23	$ 0.45	$ 0.32	$ 0.16	$ 0.26	$ 0.05
Weighted average number of shares outstanding(3):	56,312	56,312	56,312	56,559	73,727	71,692	102,562
Diluted							
Income from continuing operations	$ 0.04	$ 0.26	$ 0.22	$ 0.31	$ 0.21	$ 0.26	$ 0.35
Income (loss) from discontinued operations, net of income tax	0.02		0.01	0.01			
Extraordinary gain on acquisition			0.22				
Cumulative effect of change in accounting principle, net of income tax		(0.03)					
Preferred stock dividends					(0.05)		(0.30)
Income per share available to common stockholders	$ 0.06	$ 0.23	$ 0.45	$ 0.32	$ 0.16	$ 0.26	$ 0.05
Weighted average number of shares outstanding(3):	56,312	56,312	56,312	56,737	74,664	72,633	103,778

(1) We adopted the provisions of SFAS 143 Accounting for Retirement Obligations, resulting in a cumulative effect of change in accounting principal of $1.6 million.

(2) We recognized an extraordinary gain from the recognition of the excess of fair value over acquisition cost of $12.5 million related to an acquisition we made in 2004.

(3) The number of shares has been adjusted to reflect a 281.562-to-1 stock split in December 2005.

	As of December 31,					As of September 30,	
	2002	2003	2004	2005	2006	2006	2007
				(In thousands)			
Balance Sheet Data:							
Cash and cash equivalents	$ 1,876	$ 176	$ 12,973	$ 45,731	$ 38,948	$ 10,718	$ 32,013
Property, plant and equipment, net	$ 43,839	$ 70,289	$ 114,818	$ 337,881	$ 2,134,718	$ 517,465	$ 2,889,495
Total assets	$ 88,247	$ 127,744	$ 197,017	$ 458,683	$ 2,388,384	$ 607,717	$ 3,170,456
Long-term debt	$ 20,549	$ 24,740	$ 59,340	$ 43,133	$ 1,066,831	$ 160,913	$ 1,451,504
Redeemable convertible preferred stock	$	$	$	$	$ 439,643	$	$ 450,356
Total stockholders equity	$ 22,106	$ 33,940	$ 59,330	$ 289,002	$ 649,818	$ 311,849	$ 965,123
Total liabilities and stockholders equity	$ 88,247	$ 127,744	$ 197,017	$ 458,683	$ 2,388,384	$ 607,717	$ 3,170,456

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MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Introduction

The following discussion and analysis should be read in conjunction with the Selected Consolidated Historical Financial Data and the accompanying financial statements and related notes thereto and the Unaudited Pro Forma Condensed Combined Financial Information included elsewhere in this prospectus. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for natural gas and oil, economic and competitive conditions, regulatory changes, estimates of proved reserves, potential failure to achieve production from development projects, capital expenditures and other uncertainties, as well as those factors discussed below and elsewhere in this registration statement, particularly in Risk Factors and Cautionary Statement Concerning Forward-Looking Statements, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

Overview of Our Company

We are a rapidly expanding independent natural gas and oil company concentrating on exploration, development and production activities. We are focused on continuing the exploration and exploitation of our significant holdings in the West Texas Overthrust, which we refer to as the WTO, a natural gas prone geological region where we have operated since 1986 that includes the Piñon Field and our South Sabino and Big Canyon Prospects. We also own and operate drilling rigs and conduct related oil field services, and we own and operate interests in gas gathering, marketing and processing facilities and CO_2 gathering and transportation facilities.

On November 21, 2006, we acquired all of the outstanding membership interests in NEG Oil & Gas, or NEG, for total consideration of approximately $1.5 billion, excluding cash acquired. With core assets in the Val Verde and Permian Basins of West Texas, including overlapping or contiguous interests in the WTO, the NEG acquisition has dramatically increased our exploration and production segment operations. The NEG acquisition, coupled with numerous acquisitions of additional working interests completed during 2007, 2006 and late 2005, have significantly increased our holdings in the WTO. We also operate significant interests in the Cotton Valley Trend in East Texas and the Gulf Coast region.

During November 2007, we completed an initial public offering of our common stock, a portion of the proceeds from which were used to repay indebtedness outstanding under our senior credit facility as well as a note payable outstanding related to a recent acquisition. See further discussion of these transactions in Note 17 to the September 30, 2007 condensed consolidated financial statements contained in this prospectus.

Restatement of Previously Issued Financial Statements

Change in Method of Accounting for Oil and Gas Operations

In the fourth quarter of 2006, we changed from the successful efforts method to the full cost method of accounting for our oil and gas operations. All prior years financial statements presented have been restated to reflect the change.

Our management believes that the full cost method is preferable for a company more actively involved in the exploration and development of oil and gas reserves. The full cost method was also utilized by NEG prior to the NEG acquisition, and the assets acquired from NEG constituted more than our total oil and natural gas assets at that time.

Our financial results have been retroactively restated to reflect the conversion to the full cost method. As required by full cost accounting rules, all costs associated with property acquisition, exploration and development activities are capitalized. Exploration and development costs include dry hole costs, geological and geophysical costs, direct overhead related to exploration and development activities and other costs incurred for the purpose of finding oil and gas reserves.

In accordance with full cost accounting rules, we are subject to a limitation on capitalized costs. The capitalized cost of natural gas and oil properties, net of accumulated depreciation, depletion and amortization, may not exceed the estimated future net cash flows from proved oil and gas reserves discounted at 10%, plus the lower of cost or fair market value of unproved properties as adjusted for related tax effects which is known as the ceiling limitation. If capitalized costs exceed the ceiling limitation, the excess must be charged to expense. We did not have any adjustment to earnings due to the ceiling limitation for the periods presented herein.

Correction of an Accounting Error

In May 2007, we determined that we had incorrectly accounted for certain derivative instruments as of and for the year ended December 31, 2006 due to a clerical error. For the year ended December 31, 2006, we recognized an unrealized gain on change in fair value of derivatives related to mark-to-market adjustments of derivative instruments with a counterparty of approximately $3.0 million. As part of our first quarter 2007 closing process, we discovered that the mark-to-market adjustments booked in 2006 for the derivative instruments with this counterparty were recorded incorrectly. As part of our normal closing procedures, we requested from the counterparty our mark-to-market position. Historically, the counterparties have sent the statement in terms of our position. During the fourth quarter of 2006, we entered into derivative instruments with a new counterparty. The new counterparty confirmed the mark-to-market loss (gain) with respect to the counterparty s position, not our position, which we had requested. The position terms of the statement were not specified on the confirmation and it was recorded in error during the 2006 year end closing process. The restatement had no effect on our previously presented net cash provided by (used in) operating activities, investing activities or financing activities for any period presented.

Management took steps during the second quarter of 2007 to improve our internal control over financial reporting, including the hiring of experienced financial reporting professionals, redefining and realigning responsibilities and defining additional controls, reporting processes and procedures.

Segment Overview

Operating income is computed as segment operating revenue less direct operating costs. These measurements provide important information to us about the activity and profitability of our lines of business. Set forth in the table below is financial information regarding each of our current segments.

	Year Ended December 31,			Nine Months Ended September 30,	
	2004	2005	2006	2006	2007
			(In thousands)		
Segment revenue:					
Exploration and production	$ 37,564	$ 54,051	$ 106,413	$ 50,350	$ 320,410
Drilling and oil field services	39,211	80,151	138,657	106,255	56,999
Midstream gas services	99,044	147,499	122,892	91,214	71,131
Other	176	5,992	20,280	15,358	13,235
Total revenues	175,995	287,693	388,242	263,177	461,775

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	Year Ended December 31,			Nine Months Ended September 30,	
	2004	2005	2006	2006	2007
	(In thousands)				
Segment operating income:					
Exploration and production	14,000	14,886	17,069	8,203	138,306
Drilling and oil field services	4,206	18,295	32,946	27,178	14,252
Midstream gas services	2,636	4,096	3,528	3,138	5,958
Other	(92)	(3,224)	(16,562)	(8,778)	(20,172)
Total operating income	20,750	34,053	36,981	29,741	138,344
Interest income	56	206	1,109	448	4,201
Interest expense	(1,678)	(5,277)	(16,904)	(4,090)	(88,630)
Other income (expense)	(298)	(1,121)	671	(241)	3,078
Income before income taxes	$ 18,830	$ 27,861	$ 21,857	$ 25,858	$ 56,993

	Year Ended December 31,			Nine Months Ended September 30,	
	2004	2005	2006	2006	2007
Production data:					
Gas (Mmcf)	6,708	6,873	13,410	6,856	35,148
Oil (MBbls)	37	72	322	70	1,441
Combined equivalent volumes (Mmcfe)	6,930	7,305	15,342	7,275	43,793
Daily combined equivalent volumes (Mmcfe/d)	18.9	20.0	42.0	26.6	160.4
Average prices(1):					
Natural gas (per Mcf)	$ 4.43	$ 6.54	$ 6.19	$ 6.14	$ 6.56
Oil (per Bbl)	$ 34.03	$ 48.19	$ 56.61	$ 61.89	$ 61.67
Combined equivalent (per Mcfe)	$ 4.47	$ 6.63	$ 6.60	$ 6.38	$ 7.30
Drilling and oil field services:					
Number of operational drilling rigs owned at end of period	10	19	25	23.0	27.0(3)
Average number of operational drilling rigs owned during the period	8.0	14.3	21.9	21.0	26.0(3)
Average total revenue per rig per day(2)	$ 9,128	$ 11,503	$ 17,034	$ 17,089	$ 17,302

(1) Reported prices represent actual average prices for the periods presented and do not give effect to hedging transactions.

(2) Does not include revenues for related rental equipment.

(3) Does not include five rigs being retrofitted as of September 30, 2007.

We report the results of our operations in the following segments:

Exploration and Production Segment

We explore for, develop and produce natural gas and oil reserves, with a focus on our proved reserves and extensive undeveloped acreage positions in the WTO. We operate substantially all of our wells in our core areas and employ our drilling rigs and other drilling services in the exploration and development of our operated wells and, to a lesser extent, on our non-operated wells.

The primary factors affecting the financial results of our exploration and production segment are the prices we receive for our natural gas and oil production, the quantity of our natural gas and oil production and changes in the fair value of derivative instruments we use to reduce the volatility of the prices we receive for

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our natural gas and oil production. Because we are vertically integrated, our exploration and production activities affect the results of our oil field service and midstream segments. The NEG acquisition substantially increased our revenues and operating income in our exploration and production segment. However, because our working interest in the Piñon Field increased to approximately 83%, there are greater intercompany eliminations that affect the consolidated financial results of our oil field service and midstream segments.

Exploration and production segment revenues increased to $320.4 million in the nine months ended September 30, 2007 from $50.4 million in the nine months ended September 30, 2006, an increase of 536.4%, as a result of a 502.0% increase in volumes and a 14.4% increase in the average price we received for the natural gas and oil we produced. In the nine month period ended September 30, 2007 we increased natural gas production by 28.3 Bcf, to 35.2 Bcf and increased crude oil production by 1,371 MBbls to 1,441 MBbls. The total combined 36.5 Bcfe increase in production was due primarily to acquisitions and successful drilling in the WTO.

The average price we received for our natural gas production for the nine month period ended September 30, 2007 increased 6.8%, or $0.42 per Mcf, to $6.56 per Mcf from $6.14 per Mcf in the comparable period in 2006. The average price received for our crude oil production decreased slightly, however, to $61.67 from $61.89 for the comparable period in 2006. Including the impact of derivative contract settlements, the effective price received for natural gas for the nine month period ended September 30, 2007 was $7.11 per Mcf as compared to $8.21 per Mcf during the comparable period in 2006. Our derivatives contracts had no impact on effective oil prices during the nine months ended September 30, 2007 or the comparable period in 2006.

For the nine months ended September 30, 2007, we had $138.3 million in operating income in our exploration and production segment, compared to $8.2 million operating income for the same period in 2006. Our $270.1 million increase in exploration and production revenues was offset by a $56.1 million increase in production expenses, and a $101.9 million increase in depreciation, depletion and amortization, or DD&A, due to the step up in basis on the NEG properties. The increase in production expenses was attributable to the additional properties acquired in the NEG acquisition and operating expenses on our new wells. During the nine month period ended September 30, 2007, the exploration and production segment reported a $55.2 million net gain on our derivatives positions ($19.2 million realized gains and $36.0 million in unrealized gains) compared to a $16.2 million gain ($14.2 realized gains and $2.0 unrealized gains) in the comparable period in 2006. During 2007, we selectively entered into natural gas swaps and basis swaps by capitalizing on what we perceived as spikes in the price of natural gas or favorable basis differences between the NYMEX price and natural gas prices at our principal West Texas pricing point of Waha Hub. Unrealized gains or losses on derivative contracts represent the change in fair value of open derivative positions during the period. The change in fair value is principally measured based on period end prices as compared to the contract price. The unrealized gain recorded in the nine month period ended September 30, 2007 was attributable to a decrease in average natural gas prices at September 30, 2007 as compared to the average natural gas prices at the various contract dates.

For the year ended December 31, 2006, exploration and production segment revenues increased to $106.4 million from $54.1 million in 2005 and from $37.6 million in 2004. The increase in 2006 compared to 2005 was attributable to increased production due to successful drilling activity and approximately 40 days of production from the NEG acquisition effective November 21, 2006. NEG contributed approximately $36.9 million of revenues in the 2006 period. Production volumes increased to 15,342 Mmcfe in 2006 from 7,305 Mmcfe in 2005, representing a 8,037 Mmcfe, or 110% increase. Approximately 4,902 Mmcfe, or 61%, of the increase was attributable to the NEG production for the period from November 21, 2006 to December 31, 2006. Average combined prices were essentially unchanged at $6.60 per Mcfe as compared to $6.63 in 2005. The increase in 2005 compared to 2004 was primarily due to a 48% increase in prices. Production volumes increased approximately 6% during 2005 as compared to 2004 with average daily volumes of 20.0 Mmcfe per day and 18.9 Mmcfe per day, respectively.

Exploration and production segment operating income increased $2.2 million in 2006 to $17.1 million from $14.9 million in 2005. The increase was primarily attributable to the increased production revenues described above, approximately $12.3 million in derivative gains ($1.9 million unrealized loss) in 2006 as compared to a $4.1 million derivative loss ($1.3 million unrealized loss) in 2005, and the addition of NEG for the period from November 21, 2006 to December 31, 2006. The increase in the exploration and production segment income was substantially offset by a $20.5 million, or 106%, increase in production costs, a $26.7 million, or 380%, increase in general and administrative expenses and a $19.3 million increase in DD&A. Approximately $7.0 million of the increase in production costs was attributable to the NEG acquisition with remainder of the increase attributable to the increase in the number of wells operated in 2006 as compared to 2005. The increase in DD&A for our exploration and production segment was attributable to higher production and the increase in the full-cost pool due to the NEG acquisition. Exploration and production operating income increased to $14.9 million in 2005 from $14.0 million in 2004, due primarily to higher natural gas and oil prices and a 6% increase in volumes.

As of December 31, 2006, we had 1,001.8 Bcfe of estimated net proved reserves with a PV-10 of $1,734.3 million, while at December 31, 2005 we had 300.0 Bcfe of estimated net proved reserves with a PV-10 of $733.3 million. Our Standardized Measure of Discounted Future Net Cash Flows was $499.2 million at December 31, 2005 and $1,440.2 million at December 31, 2006. For a discussion of PV-10 and a reconciliation to Standardized Measure of Discounted Net Cash Flows, see Summary Historical Operating and Reserve Data. The increase is primarily related to the addition of the NEG reserves which was partially offset by a decrease in the price of natural gas from $8.40 per Mcf at December 31, 2005 to $5.64 per Mcf at December 31, 2006. Our estimated proved reserves at December 31, 2005 were considerably higher than our estimated proved reserves at December 31, 2004, which were 148.5 Bcfe, with an increase of $300.2 million in PV-10, due to an increase in the price of natural gas and oil, the acquisition of PetroSource and the establishment of additional proved reserves in the Piñon Field area. Estimates of net proved reserves are inherently imprecise. In order to prepare our estimates, we must analyze available geological, geophysical, production and engineering data and project production rates and the timing of development expenditures. The process also requires economic assumptions about matters such as natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and the availability of funds. We may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond our control. Over 98% of our mid-year and year-end reserve estimates are reviewed by independent petroleum reserve engineers.

Over the past several years, higher natural gas and oil prices have led to higher demand for drilling rigs, operating personnel and field supplies and services. Higher prices have also caused increases in the costs of those goods and services. To date, the higher sales prices have more than offset the higher field costs. Our ownership of drilling rigs has also assisted us in stabilizing our overall cost structure. Given the inherent volatility of natural gas and oil prices that are influenced by many factors beyond our control, we plan our activities and budget based on conservative sales price assumptions, which generally are lower than the average sales prices received in 2006. We focus our efforts on increasing natural gas reserves and production while controlling costs at a level that is appropriate for long-term operations. Our future earnings and cash flows are dependent on our ability to manage our overall cost structure to a level that allows for profitable production.

Like all exploration and production companies, we face the challenge of natural production declines. As initial reservoir pressures are depleted, natural gas and oil production from a given well naturally decreases. Thus, a natural gas and oil exploration and production company depletes part of its asset base with each unit of oil or natural gas it produces. We attempt to overcome this natural decline by drilling and acquiring more reserves than we produce. Our future growth will depend on our ability to continue to add reserves in excess of production. We will maintain our focus on managing the costs associated with adding reserves through drilling and acquisitions as well as the costs associated with producing such reserves. Our ability to add reserves through drilling is dependent on our capital resources and can be limited by many factors, including our ability to timely obtain drilling permits and regulatory approvals. In the WTO, this has not posed a problem. However, in other areas, the permitting and approval process has been more difficult in recent years due to increased activism from environmental and other groups. This has increased the time it takes to receive permits in some locations.

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Drilling and Oil Field Services Segment

We drill for our own account primarily in the WTO through our drilling and oil field services subsidiary, Lariat Services. We also drill wells for other natural gas and oil companies, primarily located in the West Texas region. Our oil field services business conducts operations that complement our drilling services operation. These services include providing pulling units, mud logging, trucking, rental tools, location and road construction and roustabout services to ourselves and to third-parties. Additionally, we provide under-balanced drilling systems only for our own account.

In October 2005, we entered into a joint venture, Larclay, with CWEI, pursuant to which we jointly acquired twelve newly-constructed rigs to be used for drilling on CWEI s prospects and for contracting to third-parties on daywork drilling contracts. All of these rigs have been delivered, although one rig has not been assembled. CWEI was responsible for financing the purchase of the rigs by the terms of the joint venture and has financed 100% of the acquisition cost of the rigs. We operate the rigs owned by the joint venture, and after the initial construction and equipping, all operating costs to maintain the equipment are borne proportionately between us and CWEI. We have a 50% interest in Larclay, and we account for this joint venture as an equity investment.

The financial results of our drilling and oil field services segment depend on many factors, particularly the demand for and the price we can charge for our services. We provide drilling services for our own account and for others, generally on a daywork, footage or turnkey contract basis. The majority of our drilling contract revenues are derived from daywork drilling contracts. However, we generally assess the complexity and risk of operations, the on-site drilling conditions, the type of equipment to be used, the anticipated duration of the work to be performed and the prevailing market rates in determining the contract terms we offer.

Daywork Contracts. Under a daywork drilling contract, we provide a drilling rig with required personnel to our customer who supervises the drilling of the well. We are paid based on a negotiated fixed rate per day while the rig is used. Daywork drilling contracts specify the equipment to be used, the size of the hole and the depth of the well. Under a daywork drilling contract, the customer bears a large portion of the out-of-pocket drilling costs, and we generally bear no part of the usual risks associated with drilling, such as time delays and unanticipated costs. As of September 30, 2007, 26 of our rigs were operating under daywork contracts and 20 of these were working for our account. Also as of September 30, 2007, the 11 operational rigs owned by Larclay were operating under daywork contracts and seven of these were working for our account. The remaining four operational Larclay rigs were working for CWEI as of September 30, 2007.

Footage Contracts. Under a footage contract, we are paid a fixed amount for each foot drilled, regardless of the time required or the problems encountered in drilling the well. As of September 30, 2007, none of our rigs were operating under footage contracts.

Turnkey Contracts. Under a typical turnkey contract, a customer will pay us to drill a well to a specified depth and under specified conditions for a fixed price, regardless of the time required or the problems encountered in drilling the well. We provide most of the equipment and drilling supplies required to drill the well. We subcontract for related services such as the provision of casing crews, cementing and well logging. Generally we do not receive progress payments and are paid only after the well is drilled. We routinely enter into turnkey contracts in areas where our experience and expertise permit us to drill wells more profitably than under a daywork contract. As of September 30, 2007, one of our rigs was operating under turnkey contracts.

Drilling and oil field services segment revenue decreased to $57.0 million in the nine month period ended September 30, 2007 from $106.3 million in the nine month period ended September 30, 2006. Operating income decreased to $14.3 million in the nine month period ended September 30, 2007 from $27.2 million in the same period in 2006. The decline in revenues and operating income is primarily attributable to an increase in the number of rigs operating on our properties and an increase in our ownership interest in our natural gas and oil properties. Our drilling and oil field services segment records revenues and operating income only on wells drilled for or on behalf of third parties. The portion of drilling costs incurred by our drilling and oil field services segment relating to our ownership interest are capitalized as part of our full-cost pool. With the NEG acquisition and other WTO property acquisitions, our average working interest has increased to approximately 85% in the wells we operate in the WTO, and the third party interest has declined to less than 20%. During the nine month period ended September 30, 2007, approximately 70% ($131.9 million) of the drilling and oil field service revenues were generated by work performed on our own account and eliminated in consolidation as compared to approximately 31% ($48.0 million) for the comparable period in 2006. The number of drilling rigs we owned increased 23.8% to an average of 26.0 rigs during the nine month period ended September 30, 2007 from an average of 21.0 rigs in the comparable period in 2006. The average daily rate we received per rig of $17,302, excluding revenues for related rental equipment and before intercompany eliminations was essentially unchanged from the comparable period in 2006. Our rig utilization rate was 91.0%, representing 826 stacked rig days in 2007. The decline in operating income was principally attributable to the increase in the number and working interest ownership in wells drilled for our own account.

During 2006, our drilling and oil field services segment reported $138.7 million in revenues, an increase of $58.5 million, or 73%, from 2005. Operating income increased to $32.9 million in 2006 from $18.3 million in 2005. The increase in revenue and operating income was primarily attributable to an increase in the number of rigs we owned and an increase in the average revenue per rig per day we earned from the rigs. The number of rigs we owned increased 32% to 25 rigs as of December 31, 2006 and the average revenue we received per rig, excluding revenues for related rental equipment, increased 48% (before intercompany eliminations) to $17,034 per day from $11,503 per day. Our margins increased primarily due to our rig rates increasing faster than our operating costs.

Drilling and oil field services segment revenue increased to $80.2 million in 2005 from $39.2 million in 2004. Operating income increased to $18.3 million in 2005 from $4.2 million in 2004. The increase in revenue and operating income was primarily attributable to an increase in the number of rigs we owned and an increase in the average revenue per rig per day we earned from the rigs. The average number of rigs we owned in 2005 increased 79% from 2004 and the average revenue we received per rig per day, excluding revenues for related rental equipment, in 2005 increased 26% from 2004 (before intercompany eliminations).

We believe our ownership of drilling rigs and related oil field services will continue to be a major catalyst of our growth. As of August 15, 2007, our drilling fleet consisted of 44 rigs, including the twelve rigs owned by Larclay. Currently, 29 of our rigs are working on properties that we operate; six of our rigs are drilling on a contract basis for third-parties; three are being retrofitted and six are idle or being repaired.

In 2005 we placed an order for 26 drilling rigs to be constructed by Chinese manufacturers for an approximate aggregate purchase price of $126.4 million, of which $75.6 million was attributable to Larclay. We believe this is a lower cost when compared to newly built U.S. manufactured rigs with similar capabilities. In the first quarter of 2007, we took delivery of the three remaining rigs that we ordered from Chinese manufacturers bringing our total deliveries to ten rigs.

Midstream Gas Services Segment

We provide gathering, compression, processing and treating services of natural gas in West Texas and the Piceance Basin in northwestern Colorado, primarily through our wholly-owned subsidiary, ROC Gas. Through our gas marketing subsidiary, Integra Energy LLC (Integra Energy), we buy and sell natural gas produced from our operated wells as well as third-party operated wells. Gas marketing revenue is one of our largest revenue components; however, it is a very low margin business. Substantially all of our marketing fees are billed on a per unit basis. On a consolidated basis, gas purchases and other costs of sales includes the total value we receive from third-parties for the gas we sell and the amount we pay for gas, which are reported as midstream and marketing expense. The primary factors affecting our midstream gas services are the quantity of gas we gather, treat and market and the prices we pay and receive for natural gas.

Midstream gas services revenue for the nine months ended September 30, 2007 was $71.1 million compared to $91.2 million in the comparable period in 2006. The quarterly and nine month decrease in midstream gas services revenues is attributable to the increase in our working interest in the WTO as a result of the NEG and other acquisitions.

Midstream gas services segment revenue decreased $24.6 million for the year ended December 31, 2006 from $147.5 million in 2005 to $122.9 million in 2006. The NEG acquisition significantly decreased our

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midstream gas services revenue as more gas was transported for our own account. We do not record midstream gas revenue for transportation, treating and processing of our own gas. Prior to the NEG acquisition, transportation, treating and processing of gas for NEG was recorded as midstream gas services revenue. Operating income decreased to $3.5 million in 2006 from $4.1 million in the 2005 period, primarily due to the NEG acquisition and start-up operating expenses for our Sagebrush processing plant in 2006. The Sagebrush plant was placed into full operation during May 2007. We have the contractual right to periodically increase fees we receive for transportation and processing based on certain indexes.

Midstream gas services revenue increased to $147.5 million in 2005 from $99.0 million in 2004, primarily due to an increase in the price of natural gas. Volumes in the midstream gas services segment increased 5% in 2005 from 2004 due to two acquisitions completed in 2005. Operating income also increased to $4.1 million in 2005 from $2.6 million in 2004, due primarily to a $1.5 million contribution from our consolidating subsidiary, Cholla Pipeline, L.P.

Other Segment

Our other segment consists primarily of our CO_2 gathering and tertiary oil recovery operations and other investments. We conduct our CO_2 gathering and tertiary oil recovery operations through PetroSource. In the fourth quarter of 2005 we acquired a majority interest in PetroSource, and in the first and second quarters of 2006 we acquired the remaining interests in PetroSource. Prior to the majority acquisition of PetroSource we accounted for PetroSource s results of operation as an equity investment in an unconsolidated subsidiary. We now include PetroSource in our other segment. Currently most of the natural gas and oil revenue we receive is from the production of natural gas; however, we expect more of our revenue to come from oil production after we initiate our CO_2 flood operations. PetroSource gathers CO_2 from natural gas treatment plants located in West Texas and transports this CO_2 for use in our and third-parties tertiary oil recovery operations.

While it is extremely difficult to accurately forecast future natural gas and oil production, we believe tertiary oil recovery operations will provide significant long-term production growth potential at reasonable rates of return with relatively low risk. The increasing emphasis on CO_2 tertiary oil recovery projects has had, and will continue to have, an impact on our financial condition in the following manner:

there is a significant delay between the initial capital expenditures for infrastructure and CO_2 injections and the resulting production increases, if any, as tertiary oil recovery operations require the construction of facilities before CO_2 flooding can commence. After the infrastructure is in place and injections begin, it usually takes an additional 18 months before the field responds (i.e. oil production increases) to the injection of CO_2;

it is anticipated that PetroSource will not be profitable for the first several years after this offering closes. The anticipated lack of profitability in the initial years is due largely to the significant outlay of capital investment in the CO_2 flood projects and the lag of revenues associated with such expenditures. Thereafter, we will recognize profits only if the tertiary oil recovery efforts are successful; and

our tertiary oil recovery projects are more expensive to operate than conventional oil fields because of the additional cost of injecting and recycling the CO_2 (primarily due to the cost of CO_2 and the significant energy requirements to re-compress the CO_2 back into a liquid state for re-injection purposes). If commodity and energy prices increase, our operating expenses in these fields will also increase because we use natural gas to compress the CO_2.

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Results of Operations

Nine months ended September 30, 2006 compared to the nine months ended September 30, 2007

Revenue. Total revenue increased 75.5% to $461.8 million for the nine months ended September 30, 2007 from $263.2 million in the same period in 2006. This increase was due to a $273.1 million increase in natural gas and oil sales and was partially offset by lower revenues in our other segments.

	Nine Months Ended September 30,			
	2006	2007	$ Change	% Change
	(In thousands)			
Revenue:				
Natural gas and crude oil	$ 46,419	$ 319,556	$ 273,137	588.4%
Drilling and services	105,713	56,928	(48,785)	(46.1)%
Midstream and marketing	91,218	71,131	(20,087)	(22.0)%
Other	19,827	14,160	(5,667)	(28.6)%
Total revenues	$ 263,177	$ 461,775	$ 198,598	75.5%

Total natural gas and crude oil revenues increased $273.1 million to $319.5 million for the nine months ended September 30, 2007, compared to $46.4 million for the same period in 2006, primarily as a result of an increase in natural gas and crude oil production volumes. Total natural gas production increased 412.7% to 35,148 Mmcf in 2007 compared to 6,856 Mmcf in 2006, while crude oil production increased 1,958.6% to 1,441 MBbls in 2007 from 70 MBbls in 2006. Approximately 32,964 Mmcfe of the 36,518 Mmcfe increase in production was attributable to the NEG acquisition. Average price received for our natural gas and crude oil production increased 14.4% in the 2007 period to $7.30 per Mcfe compared to $6.38 per Mcfe in 2006, excluding the impact of derivative contracts.

Drilling and services revenue decreased 46.1% to $56.9 million for the nine months ended September 30, 2007, compared to $105.7 million in the same period in 2006. The decline in revenues is primarily attributable to an increase in the number of rigs operating on our properties and an increase in our ownership interest in our natural gas and oil properties as a result of the NEG acquisition. The number of rigs we owned increased to 26.0 (average for the nine months ended September 30, 2007) in 2007 compared to 21.0 (average for the nine months ended September 30, 2006) in 2006, an increase of 23.8%, and the average daily revenue per rig, after considering the effect of the elimination of intercompany usage, was essentially unchanged at $17,302 per day.

Midstream and marketing revenue decreased $20.1 million, or 22.0%, with revenues of $71.1 million in the nine month period ended September 30, 2007, as compared to $91.2 million in the nine month period ended September 30, 2006. The NEG acquisition significantly decreased our midstream gas services revenues as more gas was transported for our own account. Prior to the acquisition, transportation, treating and processing of gas for NEG was recorded as midstream gas services revenue. We have the contractual right to periodically increase fees we receive for transportation and processing based on certain indexes.

Other revenue decreased to $14.2 million for the nine months ended September 30, 2007 from $19.8 million for the same period in 2006. The decrease was primarily due to the sale of various non-energy related assets to our former President and Chief Operating Officer. Revenues related to these assets are included in the 2006 period prior to its sale in August 2006. This decrease was slightly offset by an increase in revenues generated by the sale of CO_2. Other revenue is generated primarily by our CO_2 gathering and sales operations.

Operating Costs and Expenses. Total operating costs and expenses increased to $323.4 million for the nine months ended September 30, 2007, compared to $233.4 million for the same period in 2006, primarily due to increases in our production-related costs as well as an increase in corporate staff. These increases were partially offset by decreases in costs attributable to our drilling and services and midstream and marketing operations as well as increased gains on derivative instruments.

	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2007	$ Change	% Change
	(In thousands)			
Operating costs and expenses:				
Production	$ 21,625	$ 77,707	$ 56,082	259.3%
Production taxes	2,579	12,328	9,749	378.0%
Drilling and services	72,670	30,935	(41,735)	(57.4)%
Midstream and marketing	85,525	61,191	(24,334)	(28.5)%
Depreciation, depletion, and amortization natural gas and crude oil	13,932	115,876	101,944	731.7%
Depreciation, depletion and amortization other	22,106	36,545	14,439	65.3%
General and administrative	32,024	45,781	13,757	43.0%
Gain on derivative instruments	(16,176)	(55,228)	(39,052)	(241.4)%
Gain on sale of assets	(849)	(1,704)	(855)	(100.7)%
Total operating costs and expenses	$ 233,436	$ 323,431	$ 89,995	38.6%

Production expense includes the costs associated with our exploration and production activities, including, but not limited to, lease operating expense and processing costs. Production expenses increased $56.1 million primarily due to a $53.6 million increase because of the addition of the NEG properties in 2007. The remainder of the increase was due to an increase in lease operating expenses due to an increase in the number of wells we operate. Production taxes increased $9.7 million, or 378.0%, to $12.3 million primarily due to the addition of the NEG properties in 2007.

Drilling and services and midstream and marketing expenses decreased 57.4% and 28.5% respectively, for the nine months ended September 30, 2007, as compared to the same period in 2006 primarily because of the increase in the number and working interest ownership of the wells we drilled for our own account.

DD&A for our natural gas and crude oil properties increased to $115.9 million for the nine months ended September 30, 2007, from $13.9 million in the same period in 2006. Our DD&A per Mcfe increased $0.73 to $2.65 from $1.92 in the comparable period in 2006. The increase is primarily attributable to the NEG acquisition, which increased our depreciable properties by the purchase price plus future development costs and increased production. Our production increased 502.0% to 43.8 Bcfe from 7.3 Bcfe in 2006.

DD&A for our other assets consists primarily of depreciation of our drilling rigs and other equipment. The increase in DD&A for our drilling and oil field services equipment was due primarily to the increase in the number of rigs we own. We calculate depreciation of property and equipment using the straight-line method over the estimated useful lives of the assets, which range from three to 25 years. Our drilling rigs and related oil field services equipment are depreciated over an average seven-year useful life.

General and administrative expenses increased $13.8 million to $45.8 million for the nine months ended September 30, 2007, from $32.0 million for the comparable period in 2006. The increase was principally attributable to a $21.7 million increase in corporate salaries and wages which was due to a significant increase in corporate and support staff. As of September 30, 2007, we had 2,205 employees as compared to 1,319 at September 30, 2006. The increase in salaries and wages was partially offset by a $3.2 million decrease in stock compensation expense. As part of a severance package for certain executive officers, the Board of

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Directors approved the acceleration of vesting of certain stock awards resulting in increased compensation expense recognized during the nine months ended September 30, 2006.

For the nine month period ended September 30, 2007, we recorded a gain of $55.2 million ($36.1 million unrealized gain and $19.1 million realized gain) on our derivatives instruments compared to a $16.2 million gain ($2.0 million unrealized gain and $14.2 million realized gain) for the comparable period in 2006. During 2007, we selectively entered into natural gas swaps and basis swaps by capitalizing on what we perceived as spikes in the price of natural gas or favorable basis differences between the NYMEX price and natural gas prices at our principal West Texas pricing point of Waha Hub. Unrealized gains or losses on derivatives contracts represent the change in fair value of open derivatives positions during the period. The change in fair value is principally measured based on period end prices as compared to the contract price. The unrealized gain recorded in the nine month period ended September 30, 2007 was attributable to a decrease in average natural gas prices at September 30, 2007 as compared to the average natural gas prices at the various contract dates.

Other Income (Expense). Total other expense increased to $81.4 million in the nine month period ended September 30, 2007, from $3.9 million in the nine month period ended September 30, 2006. The increase is reflected in the table below.

	Nine Months Ended September 30, 2006	2007	$ Change	% Change
	(In thousands)			
Other income (expense):				
Interest income	$ 448	$ 4,201	$ 3,753	837.7%
Interest expense	(4,090)	(88,630)	(84,540)	(2067.0)%
Minority interest	(281)	(321)	(40)	(14.2)%
Income (loss) from equity investments	40	3,399	3,359	8397.5%
Total other expense	(3,883)	(81,351)	(77,468)	(1995.1)%
Income before income taxes	25,858	56,993	31,135	120.4%
Income tax expense	6,931	21,002	14,071	203.0%
Net income	$ 18,927	$ 35,991	$ 17,064	90.2%

Interest income increased to $4.2 million for the nine months ended September 30, 2007, from $0.4 million for the same period in 2006. This increase was due to interest income from investment of excess cash after the repayment of debt.

Interest expense increased to $88.6 million for the nine months ended September 30, 2007, from $4.1 million for the same period in 2006. This increase was attributable to increased average debt balances. To finance the NEG acquisition, we entered into a $750 million senior credit facility, which has an initial borrowing base of $300 million, and an $850 million senior bridge facility. In March 2007, we entered into a $1.0 billion term loan and sold 17.8 million shares of common stock in a private placement. A portion of the proceeds from the senior unsecured term loan was used to repay the bridge loan. Please read Liquidity and Capital Resources.

During the nine months ended September 30, 2007, we reported income from equity investments of $3.4 million as compared to $40,000 in the comparable period in 2006. Approximately $1.6 million of the increase was attributable to income from our interest in the Grey Ranch processing plant which has experienced increased profitability due to higher levels of utilization during the nine months ended September 30, 2007 as compared to the same period in 2006. Approximately $1.8 million of the increase was attributable to income from Larclay as all of Larclay s rigs have now been delivered and all but one rig are operational.

We reported an income tax expense of $21.0 million for the nine months ended September 30, 2007, as compared to an expense of $6.9 million for the same period in 2006. The current period income tax expense

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represents an effective income tax rate of 36.9% as compared to 26.8% in the comparable period in 2006. The lower effective income tax rate in 2006 was attributable to favorable percentage depletion deductions during that period.

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

Revenue. Total revenue increased to $388.2 million in 2006 from $287.7 million in 2005, which is further explained by the categories below.

	Year Ended December 31, 2005	Year Ended December 31, 2006	$ Change	% Change
	(In thousands)			
Revenue:				
Natural gas and crude oil	$ 49,987	$ 101,252	$ 51,265	102.6%
Drilling and services	80,343	139,049	58,706	73.1%
Midstream and marketing	147,133	122,896	(24,237)	(16.5)%
Other	10,230	25,045	14,815	144.8%
Total revenues	$ 287,693	$ 388,242	$ 100,549	35.0%

Natural gas and crude oil revenue increased $51.3 million to $101.3 million in 2006 from $50.0 million in 2005. This was primarily a result of an increase in natural gas production volumes. Total natural gas production almost doubled to 13,410 Mmcf in 2006 compared to 6,873 Mmcf in 2005. Natural gas prices decreased $0.35, or 5%, in the 2006 period to $6.19 per Mcf compared to $6.54 per Mcf in 2005.

Drilling and services revenue increased 73% to $139.0 million for the year ended December 31, 2006 compared to $80.3 million in the same period in 2005, primarily due to an increase in the number of drilling rigs we owned and to an increase in the average daily revenue per rig. The number of rigs we owned increased to 25 (21.9 average for the year) as of December 31, 2006 compared to 19 (14.3 average for the year) in 2005, an increase of 32%, and the average daily revenue per rig, after considering the effect of the elimination of intercompany usage, increased 48% to $17,034 in 2006 compared to $11,503 in 2005. Additionally, the revenue from our heavy hauling trucking subsidiary increased $7.8 million during the comparison period due to an expansion of our trucking services. The revenue from our pulling unit operations increased $7.7 million because of an increase in the demand for these oil field services and an increase in the rate we charge.

Midstream and marketing revenue decreased $24.2 million from 2005 with revenues of $122.9 million during the year ended December 31, 2006 as compared to $147.1 million in 2005. We do not record midstream and marketing revenues for marketing, transportation, treating and processing of our own gas. The NEG acquisition significantly decreased our midstream gas services revenues as more gas was transported and marketed for our own account. Prior to the NEG acquisition, transportation, treating and processing of gas for NEG was recorded as midstream and marketing revenue. We have the contractual right to periodically increase fees we receive for transportation and processing based on certain indexes.

Other revenues increased $14.8 million to $25.0 million in 2006 from $10.2 million in 2005. The increase was primarily attributable to an increase of $12.0 million in CO_2 and tertiary oil recovery revenues. In December 2005, we acquired an additional equity interest in PetroSource which increased our ownership interest to 86.5%, resulting in the consolidation of PetroSource commencing in the fourth quarter of 2005. We recorded PetroSource revenues for the full year in 2006. The remainder of the increase was attributable to additional administration fees collected from operating natural gas and oil wells and lease acreage income received as a result of an increase in the number of wells, an increase in overhead rates and an increase in leasing activities. Approximately $0.9 million of the increase was related to an increase of revenue from Stockton Plaza.

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Operating Costs and Expenses. Total operating costs and expenses increased $97.6 million to $351.3 million in 2006 from $253.6 million in 2005, which is further explained by the categories below.

	Year Ended December 31, 2005	2006	$ Change	% Change
		(In thousands)		
Operating costs and expenses:				
Production	$ 16,195	$ 35,149	$ 18,954	117.0%
Production taxes	3,158	4,654	1,496	47.4%
Drilling and services	52,122	98,436	46,314	88.9%
Midstream and marketing	141,372	115,076	(26,296)	(18.6)%
Depreciation, depletion and amortization-natural gas and oil	9,313	26,321	17,008	182.6%
Depreciation, depletion and amortization-other	14,893	29,305	14,412	96.8%
General and administrative	11,908	55,634	43,726	367.2%
Loss (gain) on derivative instruments	4,132	(12,291)	(16,423)	(397.5)%
Loss (gain) on sale of assets	547	(1,023)	(1,570)	(287.0)%
Total operating costs and expenses	$ 253,640	$ 351,261	$ 97,621	38.5%

Production expense increased to $35.1 million in 2006 from $16.2 million in 2005 primarily due to the increase in the number of wells operated in 2006 as compared to 2005, the addition of NEG for the period from November 21, 2006 to December 31, 2006 and the addition of PetroSource for the full year in 2006 as compared to one quarter in 2005. Approximately $7.5 million of the increase was attributable to the NEG acquisition and approximately $3.2 million of the increase was attributable to PetroSource with the remainder of the increase due to an increase in the number of wells we operate.

Production taxes increased $1.5 million, or 47%, to $4.7 million due to the increase in natural gas production, which was partially offset by a decline in realized natural gas prices. Production taxes are generally assessed at the wellhead and are based on the volumes produced times the price received.

Drilling and services expenses increased 89% to $98.4 million in 2006 from $52.1 million in 2005, primarily due to an increase in our oil field services operating expense. Oil field services operating expenses, including fuel, repairs and maintenance, increased $14.2 million due to an increase in the number of drilling rigs we owned as well as work we performed on a turnkey and footage basis rather than a day rate basis.

Midstream and marketing expenses decreased $26.3 million, or 19%, to $115.1 million in 2006 as compared to $141.4 million in 2005 due to a decrease in the average price paid for gas that we market and a decrease in gas purchased from third parties as we focused our marketing efforts more on our own production.

DD&A relating to our natural gas and oil properties increased 183% to $26.3 million in 2006 from $9.3 million in 2005. The increase was primarily attributable to a 110% increase in year-over-year production and a 35% increase in DD&A. The average DD&A per Mcfe was $1.72 for the year ended December 31, 2006 as compared to $1.27 in 2005. The increase in the DD&A was attributable to the NEG acquisition which added significantly higher reserves at a higher cost per Mcfe.

DD&A related to our other property, plant and equipment increased $14.4 million, or 97%, primarily due to our investment in additional drilling rigs and oil field service equipment.

General and administrative expense increased $43.7 million to $55.6 million in 2006 from $11.9 million in 2005, due in part to an increase in expense related to salaries and wages as we added a significant amount of staff to accommodate our acquisitions and our increased drilling activities, a $5 million dispute settlement, a $3.6 million increase in property and franchise taxes, higher administrative costs associated with our increase in staff including rent, utilities, insurance and office equipment and supplies, a $2.5 million increase in bad debt expense and an increase in legal and professional expenses. Legal and professional fees increased $4.7 million due primarily to an increase in legal fees relating to two legal issues and increased audit fees.

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For the year ended December 31, 2006, we recorded a gain on derivative instruments of $12.3 million compared to a loss of $4.1 million in 2005. We entered into collars and fixed-price swaps to mitigate the effect of price fluctuations of natural gas and oil. We enter into natural gas basis swaps to mitigate the risk of fluctuations in pricing differentials between our natural gas well head prices and benchmark spot prices. We have not designated any of these derivative contracts as hedges for accounting purposes. We record derivatives contracts at fair value on the balance sheet, and gains or losses resulting from changes in the fair value of our derivative contracts (unrealized) are recognized as a component of operating costs and expenses. Unrealized gains or losses are realized upon settlement. During the first eleven months of 2006, we settled or terminated all of our natural gas derivative contracts and realized a net gain of approximately $14.2 million. We did not enter into any new derivative instruments until December 2006 and the first quarter of 2007. Offsetting the 2006 net realized gain on the settlement or early termination of our derivative instruments was a net unrealized loss of $1.9 million which represented the change in fair value of our derivatives instruments from the purchase date in early December 2006 to December 31, 2006. Generally, we record unrealized gains on our swaps and fixed-price swaps when natural gas and oil commodity prices decrease and record unrealized losses as natural gas and oil prices increase. We record unrealized gains on our basis swaps if the pricing differential increases and unrealized losses as the pricing differential decreases. Gains or losses on derivatives contracts are realized upon settlement. During 2005 we did not terminate any derivatives positions and realized a loss of $2.8 million due to normal settlements. Future volatility in natural gas and oil prices could have an adverse effect on the operating results of our exploration and production segment.

Other Income (Expense). Total other expense increased to $15.1 million in 2006 from $6.2 million in 2005. The increase is discussed in the table below.

	Year Ended December 31, 2005	Year Ended December 31, 2006	$ Change	% Change
	(In thousands)			
Other income (expense):				
Interest income	$ 206	$ 1,109	$ 903	438.3%
Interest expense	(5,277)	(16,904)	(11,627)	(220.3)%
Minority interest	(737)	(296)	441	59.8%
Income (loss) from equity investments	(384)	967	1,351	351.8%
Total other expense	(6,192)	(15,124)	(8,932)	(144.3)%
Income before income taxes	27,861	21,857	(6,004)	(21.5)%
Income tax expense	9,968	6,236	(3,732)	(37.4)%
Income from discontinued operations, net of tax	229		(229)	(100.0)%
Net income	$ 18,122	$ 15,621	$ (2,501)	(13.8)%

Interest income increased to $1.1 million in 2006 from $0.2 million in 2005. This increase was due to interest income recognized in 2006 related to excess cash balances with various financial institutions.

Interest expense increased to $16.9 million in 2006 from $5.3 million in 2005. This increase was due to the additional debt that we incurred to finance our purchase of NEG.

We recorded income from equity investments of $1.0 million in 2006 as compared to a $0.4 million loss in 2005. The 2005 loss was primarily due to PetroSource. We accounted for PetroSource under the equity method during the first nine months of 2005.

Income tax expense decreased to $6.2 million in 2006 from $10.0 million in 2005 primarily due to a decrease in our effective income tax rate. During 2006, we realized a $3.5 million reduction in tax expense from our percentage depletion deduction, which was partially offset by $1.3 million in additional state income taxes.

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

Revenue. Total revenue increased to $287.7 million in 2005 from $176.0 million in 2004, which is further explained by the categories below.

	Year Ended December 31, 2004	Year Ended December 31, 2005	$ Change	% Change
		(In thousands)		
Revenue:				
Natural gas and crude oil	$ 33,685	$ 49,987	$ 16,302	48.4%
Drilling and services	39,417	80,343	40,926	103.8%
Midstream and marketing	98,906	147,133	48,227	48.8%
Other	3,987	10,230	6,243	156.6%
Total revenues	$ 175,995	$ 287,693	$ 111,698	63.5%

Natural gas and crude oil revenue increased $16.3 million to $50.0 million in 2005 from $33.7 million in 2004. This was due to an increase in the average price we received for the natural gas and oil we produced, which increased to $6.63 per Mcfe in 2005 from $4.47 per Mcfe in 2004. Combined volumes were essentially unchanged from 2004 to 2005.

Drilling and services revenue increased to $80.3 million in 2005 from $39.4 million in 2004, primarily due to an increase in the number of drilling rigs we owned and an increase in the average daily revenue we earned from our rigs. Average daily revenue per rig, after considering the effect of the elimination of intercompany usage, increased to $11,503 in 2005 from $9,128 in 2004, and our rig fleet increased to 19 (14.3 average) rigs in 2005 from ten (8.0 average) rigs in 2004. Revenue from our oil field trucking division increased $2.9 million because this division started operations in 2005, and our air compression rental increased $2.0 million due to an increase in the number of compressor units in operation.

Midstream and marketing revenue increased to $147.1 million in 2005 from $98.9 million in 2004, primarily due to an increase in the price of natural gas and a 5% increase in volumes. Following a review of area gathering fees in May 2005, we recommended and our partners accepted a 43% increase in the gathering fees we charge to $0.10 per Mcf from $0.07 per Mcf. The plant fee also increased in April 2005 from $0.21 to $0.22, a 3% increase.

Other revenues increased $6.2 million, or 157%, primarily due to a $3.8 million increase in CO_2 and tertiary oil recovery revenue in 2005 from $0 in 2004. The increase was due to our consolidation of PetroSource in 2005. Through September 30, 2005, PetroSource was accounted for under the equity method. The remainder of the increase was due to an increase in the fees and other income collected from operating natural gas and oil wells and conducting related activities.

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Operating Costs and Expenses. Total operating costs and expenses increased $98.4 million to $253.6 million in 2005 from $155.2 million in 2004, which is further explained by the categories below.

	Year Ended December 31, 2004	2005	$ Change	% Change
	(In thousands)			
Operating costs and expenses:				
Production	$ 10,230	$ 16,195	$ 5,965	58.3%
Production taxes	2,497	3,158	661	26.5%
Drilling and services	26,442	52,122	25,680	97.1%
Midstream and marketing	96,180	141,372	45,192	47.0%
Depreciation, depletion and amortization-natural gas and oil	4,909	9,313	4,404	89.7%
Depreciation, depletion and amortization-other	7,765	14,893	7,128	91.8%
General and administrative	6,554	11,908	5,354	81.7%
Loss on derivative instruments	878	4,132	3,254	370.6%
Loss (gain) on sale of assets	(210)	547	757	360.5%
Total operating costs and expenses	$ 155,245	$ 253,640	$ 98,395	63.4%

Production expense increased to $16.2 million in 2005 from $10.2 million in 2004 primarily as a result of an increase in lease operating expense. Lease operating expense increased $1.6 million, primarily due to an increase in the number of wells operated. The consolidation of PetroSource added $2.2 million in 2005 production expense. In December 2005, we increased our equity interest in PetroSource to 86.5% which required us to consolidate PetroSource effective in the fourth quarter of 2005. Generally, our production expense has increased along with the growth in our exploration and production activities.

Production taxes increased 27% primarily as a result of an increase in the average price realized on our natural gas production of $2.11 per Mcf.

Drilling and services expenses increased 97% to $52.1 million in 2005 from $26.4 million in 2004, primarily due to an increase in our oil field services operating expense. Oil field services operating expenses, including fuel, repairs and maintenance, increased $14.2 million due to an increase in the number of drilling rigs we owned as well as work we performed on a turnkey and footage basis rather than a day rate basis.

Midstream and marketing increased 47% to $141.4 million in 2005 from $96.2 million in 2004, primarily due to a 48% increase in the average price of natural gas paid by our marketing company. Volumes during 2005 were essentially unchanged from 2004.

DD&A relating to our natural gas and oil properties increased 90% to $9.3 million in 2005 from $4.9 million in 2004. The increase was primarily attributable to a 79% increase in our DD&A in 2005 and a 5% increase in production volumes. The average DD&A was $1.27 per Mcfe for the year ended December 31, 2005 as compared to $0.71 per Mcfe in 2004. The increase in the DD&A was attributable to our increased drilling activities which added reserves at a higher cost per Mcfe.

DD&A for our other property, plant and equipment increased $7.1 million, or 92%, primarily due to our investment in additional drilling rigs and oil field service equipment.

General and administrative expense increased $5.3 million to $11.9 million in 2005 from $6.6 million in 2004, primarily as a result of an increase in salaries and wages of $4.3 million and a slight increase in legal and professional expenses.

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Other Income (Expense). Total other expense increased to $6.2 million in 2005 from $1.9 million in 2004. The increase is discussed in the table below.

	Year Ended December 31, 2004	Year Ended December 31, 2005	$ Change	% Change
	(In thousands)			
Other income (expense):				
Interest income	$ 56	$ 206	$ 150	267.9%
Interest expense	(1,678)	(5,277)	(3,599)	(214.5)%
Minority interest	(262)	(737)	(475)	(181.3)%
Loss from equity investments	(36)	(384)	(348)	(966.7)%
Total other expense	(1,920)	(6,192)	(4,272)	(222.5)%
Income before income taxes	18,830	27,861	9,031	48.0%
Income tax expense	6,433	9,968	3,535	55.0%
Income from discontinued operations, net of tax	451	229	(222)	(49.2)%
Extraordinary gain	12,544		(12,544)	(100.0)%
Net income	$ 25,392	$ 18,122	$ (7,270)	(28.6)%

Interest expense increased to $5.3 million in 2005 from $1.7 million in 2004. This increase was due to the additional debt that we incurred to finance our investment in natural gas and oil properties and oil field services equipment, including the additional drilling rigs.

The increase in loss from equity investments was primarily due to the operating loss from our equity investment in Grey Ranch, L.P. in 2005.

Income tax expense increased to $10.0 million in 2005 from $6.4 million in 2004 primarily due to an increase in income before taxes, which increased to $27.9 million in 2005 from $18.8 million in 2004. Our effective tax rate for the year ended December 31, 2005 increased slightly to 36% from 34% in 2004.

The extraordinary gain was attributable to our purchase of the Foreland Corporation in 2004 and represented the difference between the fair value of assets acquired and the purchase price. The fair value of the assets acquired was $13.8 million and the purchase price was $1.2 million.

Liquidity and Capital Resources

Summary

Our operating cash flow is influenced mainly by the prices that we receive for our natural gas and oil production; the quantity of natural gas we produce; and, to a lesser extent, the quantity of oil we produce; the success of our development and exploration activities; the demand for our drilling rigs and oil field services and the rates we receive for these services; and the margins we obtain from our natural gas and CO_2 gathering and processing contracts.

During 2006 and the first quarter of 2007, we entered into various debt and equity transactions to fund the acquisition of NEG and our 2007 capital expenditure program. As of September 30, 2007, our cash and cash equivalents were $32.0 million, and we had approximately $300.0 million available under our senior credit facility. The significant cash balance at September 30, 2007 was the result of borrowings under our senior credit facility in anticipation of an acquisition that closed subsequent to quarter-end. On November 9, 2007, we repaid amounts outstanding under our senior credit facility with a portion of the proceeds from our initial public offering. There are currently no amounts outstanding under our senior credit facility. As of September 30, 2007, we had $1,452 million in total debt outstanding.

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Cash Flows from Continuing Operations

Our cash flows from continuing operations are as follows:

	Year Ended December 31,			Nine Months Ended September 30,	
	2004	2005	2006	2006	2007
			(In thousands)		
Cash Flows from Continuing Operations:					
Cash flows provided by operating activities	$ 38,458	$ 63,297	$ 67,349	$ 67,500	$ 239,556
Cash flows used in investing activities	(59,408)	(155,826)	(1,340,567)	(223,256)	(897,341)
Cash flows provided by financing activities	34,700	126,413	1,266,435	120,743	650,850
Net increase (decrease) in cash and cash equivalents	$ 13,750	$ 33,884	$ (6,783)	$ (35,013)	$ (6,935)

Operating Activities. Net cash provided by operating activities for the nine months ended September 30, 2007 and 2006 were $239.6 million and $67.5 million, respectively. The increase in cash provided by operating activities from 2006 to 2007 was primarily due to our 502.0% increase in production volumes as a result of the NEG and various other acquisitions as well as our drilling success. Also, contributing to this increase was a 241.4% increase in realized and unrealized gains on our derivative contracts. These increases were partially offset by increases in general and administrative costs such as salaries and wages.

Cash flows provided by operating activities increased $4.0 million to $67.3 million in 2006 from $63.3 million in 2005 primarily due to an increase in non-cash DD&A of $31.4 million and an increase in non-cash stock-based compensation expense of $8.3 million as net income decreased approximately $2.5 million in 2006 over 2005. The increases were substantially offset by changes in operating assets and liabilities.

Cash flows provided by continuing operating activities increased $24.8 million to $63.3 million in 2005 from $38.5 million in 2004, due primarily to an increase in operating income and an increase in non-cash expenses. Operating income increased $13.3 million whereas net income decreased $7.3 million. The 2004 period included a $12.5 million extraordinary gain that had no effect on cash flow from operations. DD&A increased $11.5 million, and the remainder of the change was due to a $0.9 million net increase in operating assets and liabilities and a $3.1 million change due to changes in fair value of derivatives contracts.

Investing Activities. Cash flows used in investing activities increased to $897.3 million in the nine month period ended September 30, 2007 from $223.3 million in the 2006 period as we continued to ramp up our capital expenditure program. For the nine month period ended September 30, 2007, our capital expenditures were $706.6 million in our exploration and production segment, $104.8 million for drilling and oil field services, $45.4 million for midstream gas services and $38.4 million for other capital expenditures. During the same period in 2006, capital expenditures were $88.9 million in our exploration and production segment, $53.8 million for drilling and oil field services, $25.4 million for midstream gas services and $13.1 million for other capital expenditures.

Cash flows used in investing activities increased to $1,341 million for the year ended December 31, 2006 from $155.8 million in 2005 and $59.4 million in 2004. During 2006, our cash flows used in investing activities included acquisitions of $1,054 million, including the NEG acquisition described above. During the comparison period, exploration and production capital expenditures increased to $170.9 million in 2006 from $61.2 million in 2005 and $29.1 million in 2004 primarily because of the additional wells that were drilled in the Piñon Field in 2006 and 2005. Capital expenditures for drilling and oil field services increased to $89.8 million in 2006 from $43.7 million in 2005 and $22.7 million in 2004 due to an increase in the number of drilling rigs. Proceeds from the sale of assets increased to $19.7 million in 2006 from $3.3 million in 2005 and $1.4 million in 2004.

Financing Activities. Since December 2005, we have used equity issuances, borrowings and, to a lesser extent, our cash flows from operations to fund our rapid growth. Proceeds from borrowings increased to $1,262.8 million for the nine months ended September 30, 2007, and we repaid approximately $879.6 million leaving net borrowings during the period of approximately $383.2 million. We also received net proceeds of approximately $318.7 million from a private placement of our common stock. We used the net proceeds from the term loan and the common stock issuance to repay the senior bridge facility and to repay all of our outstanding borrowings under our senior credit facility. Our financing activities provided $650.9 million in cash for the nine month period ended September 30, 2007 compared to $120.7 million in the comparable period in 2006.

During the year ended December 31, 2006 we incurred net borrowings of $743 million, raised $100.8 million from issuances of common stock and raised $439.5 million from an issuance of redeemable convertible preferred stock. Our net borrowings, common stock issuances and issuance of redeemable preferred stock in 2006 were primarily used to finance the NEG acquisition as well as our 2006 capital expenditure program. During 2005 we received proceeds of $173.1 million from the issuance of common stock and had net repayments of $53.8 million as compared to net borrowings of $34.8 million in 2004. Most of our borrowings in 2005 funded the acquisition of our drilling rigs, our exploration and production activities and the expansion of our gathering and treating assets. In December 2005, we received $173.1 million in net proceeds from a private placement of 12.5 million shares of common stock, which was primarily used to reduce outstanding borrowings.

Credit Facilities and Other Indebtedness

Senior Credit Facility. On November 21, 2006, we entered into a new $750 million senior secured revolving credit facility (the senior credit facility) with Bank of America, N.A., as Administrative Agent and Banc of America Securities LLC as Lead Arranger and Book Running Manager. The senior credit facility matures on November 21, 2011.

The proceeds of the senior credit facility were used to (i) partially finance the NEG acquisition, (ii) refinance our existing senior secured revolving credit facility and NEG s existing credit facility, and (iii) pay fees and expenses related to the NEG acquisition and our existing credit facility. Future borrowings under the senior credit facility will be available for capital expenditures, working capital and general corporate purposes and to finance permitted acquisitions of natural gas and oil properties and other assets related to the exploration, production and development of natural gas and oil properties. The senior credit facility will be available to be drawn on and repaid without restriction so long as we are in compliance with its terms, including certain financial covenants.

The senior credit facility contains various covenants that limit our and certain of our subsidiaries ability to grant certain liens; make certain loans and investments; make distributions; redeem stock; redeem or prepay debt; merge or consolidate with or into a third party; or engage in certain asset dispositions, including a sale of all or substantially all of our assets. Additionally, the senior credit facility limits our and certain of our subsidiaries ability to incur additional indebtedness with certain exceptions, including under the senior unsecured bridge facility (as discussed below), which was repaid in full during March 2007.

The senior credit facility also contains financial covenants, including maintenance of agreed upon levels for the ratio of (i) our total funded debt to EBITDAX (as defined in the senior credit facility), which may not exceed 4.5:1.0 calculated using the last fiscal quarter on an annualized basis as of the end of fiscal quarters ending on or before September 30, 2008 and calculated using the last four completed fiscal quarters thereafter, (ii) our ratio of EBITDAX to interest expense plus current maturities of long-term debt, which must be at least 2.5:1.0 calculated using the last fiscal quarter on an annualized basis as of the end of fiscal quarters ending on or before September 30, 2008 and calculated using the last four completed fiscal quarters thereafter, and (iii) our current ratio, which must be at least 1.0:1.0. As of the end of the third quarter 2007 we were in compliance with these financial covenants.

The obligations under the senior credit facility are secured by first priority liens on all shares of capital stock of each of our present and future subsidiaries; all intercompany debt of us and our subsidiaries; and substantially all of our assets and the assets of our guarantor subsidiaries, including proven natural gas and oil reserves representing at least 80% of the present discounted value (as defined in the senior credit facility) of our proven natural gas and oil reserves reviewed in determining the borrowing base for the senior credit facility (as determined by the Administrative Agent). Additionally, the obligations under the senior credit facility will be guaranteed by certain of our subsidiaries.

The borrowing base for the senior credit facility is determined by the administrative agent in its sole discretion in accordance with its normal and customary natural gas and oil lending practices and approved by lenders. The reaffirmation of an existing borrowing base amount or an increase in the borrowing base will require approval by Required Lenders (as defined in the senior credit facility). The borrowing base is subject to review semi-annually; however, Required Lenders reserve the right to have (a) one additional redetermination within the first twelve months from the closing date and (b) one additional redetermination of the borrowing base per calendar year thereafter. Unscheduled redeterminations may be made at our request, but are limited to two such requests during the twelve months following the closing date and one request per twelve months thereafter.

The borrowing base includes proved developed producing reserves, proved developed non-producing reserves and proved undeveloped reserves and was $700.0 million as of September 2007. As of September 30, 2007, we had outstanding indebtedness of $400 million on our senior credit facility. We repaid all outstanding borrowings under this facility on November 9, 2007, and there are currently no amounts outstanding under the senior credit facility.

At our election, interest under the senior credit facility is determined by reference to (i) the British Bankers Association LIBOR rate, or LIBOR, plus an applicable margin between 1.25% and 2.00% per annum or (ii) the higher of the federal funds rate plus 0.5% or the prime rate plus, in either case, an applicable margin between 0.25% and 1.00% per annum. Interest will be payable quarterly for prime rate loans and at the applicable maturity date for LIBOR loans, except that if the interest period for a LIBOR loan is six months, interest will be paid at the end of each three-month period. The average interest rates paid on amounts outstanding under our senior credit facility for the three and nine month periods ended September 30, 2007 were 7.08% and 7.62%, respectively.

If an event of default exists under the senior credit facility, the lenders may accelerate the maturity of the obligations outstanding under the senior credit facility and exercise other rights and remedies. Each of the following will be an event of default:

- failure to pay any principal when due or any interest, fees or other amount within certain grace periods;
- failure to perform or otherwise comply with the covenants in the credit agreement or other loan documents, subject, in certain instances, to certain grace periods;
- bankruptcy or insolvency events involving us or our subsidiaries;
- a change of control (as defined in the senior credit facility).

March 2007 Term Loan. On March 22, 2007, we entered into a $1 billion senior unsecured term loan. The proceeds of the term loan were used to partially repay the senior bridge facility described below. The term loan includes both a floating rate tranche and fixed rate tranche.

We issued $350 million at a variable rate with interest payable quarterly and principal due on April 1, 2014 (the Variable Rate Term Loans). The Variable Rate Term Loans bear interest, at our option, at LIBOR plus 3.625% or the higher of (i) the federal funds rate, as defined, plus 3.125% or (ii) a Bank s prime rate plus 2.625%. After April 1, 2009 the Variable Rate Term Loans may be prepaid in whole or in part with a prepayment penalty. The average interest rates paid on amounts outstanding under our variable rate term loans for the three and nine month periods ended September 30, 2007 were 8.99% and 8.98%, respectively.

We issued $650 million at a fixed rate of 8.625% with principal due on April 1, 2015 (the Fixed Rate Term Loans). Under the terms of the Fixed Rate Term Loans, interest is payable quarterly and during the first four years interest may be paid, at our option, either entirely in cash or entirely with additional Fixed Rate Term Loans. If we elect to pay the interest due during any period in additional Fixed Rate Term Loans, the interest rate increases to 9.375% during such period. After April 1, 2011 the Fixed Rate Term Loans may be prepaid in whole or in part with prepayment penalties.

After March 22, 2008, but not later than April 30, 2008, we are required to offer to exchange the term loan for senior unsecured notes with registration rights. The senior unsecured notes will have substantially similar terms and conditions as the term loan. If the exchange does not occur by May 31, 2008, the interest rate on the term loan will increase by 0.25% every 90 days up to a maximum of 0.50%. The term loan contains other covenants which are ordinary and customary including limitations on the incurrence of indebtedness, payment of dividends, asset sales, certain asset purchases, transactions with related parties and consolidation or merger agreements.

Other Indebtedness. We have financed a portion of our drilling rig fleet and related oil field services equipment through notes with Merrill Lynch Capital Corporation. At September 30, 2007, the aggregate outstanding balance of these credit agreements was $51.3 million, with a fixed interest rate ranging from 7.64% to 8.87%. The notes have a final maturity date of November 1, 2010, aggregate monthly installments for principal and interest in the amount of $1.2 million and are secured by the equipment. The notes have a prepayment penalty (currently 1-3%) in the event we repay the notes prior to maturity.

We have financed the purchase of various vehicles, oil field services equipment and other equipment used in our business. The aggregate outstanding balance of these notes as of December 31, 2006 was $4.5 million. These notes were repaid during the three months ended September 30, 2007 with borrowings under our senior credit facility.

On October 14, 2005, Sagebrush Pipeline, LLC borrowed $4.0 million from Bank of America, N.A. for the purpose of completing the gas processing plant and pipeline in Colorado. This loan was repaid in full in July 2007.

Senior Bridge Facility. On November 21, 2006, we also entered into an $850 million senior unsecured bridge facility (the senior bridge facility) with Banc of America Bridge LLC, as the Initial Bridge Lender and Banc of America Securities LLC, Credit Suisse Securities, Goldman Sachs Credit Partners L.P., and Lehman Brothers Inc., as joint lead arrangers and bookrunners. This facility was repaid in full during March 2007 with proceeds from our senior unsecured term loan.

Together with borrowings under the senior credit facility, the proceeds from the senior bridge facility were used to (i) partially finance the NEG acquisition, (ii) refinance our existing senior secured revolving credit facility and NEG s existing credit facility, and (iii) pay fees and expenses related to the NEG acquisition and our existing credit facility. The obligations under the senior bridge facility are general unsecured obligations of our company and certain of our subsidiaries. The senior bridge facility was paid in full in March 2007 with the proceeds from the term loan and the common stock issuance described above.

The senior bridge facility contained customary restrictive covenants pertaining to management and operations of our company and our subsidiaries similar to those contained in the senior credit facility. Generally, amounts outstanding under the senior bridge facility bore interest at a base rate equal to the greater of (i) three-month LIBOR plus an applicable margin initially equal to 4.50% per annum or (ii) 9.0% per annum plus an applicable margin initially equal to 0% per annum; provided that the applicable margin for the senior bridge facility will increase by 0.5% at the end of the period that is six months after the closing date for the senior bridge facility and an additional 0.25% per quarter thereafter for as long as the senior bridge facility, Rollover Loans or Exchange Notes remain outstanding subject to a cap of 11% (subject to certain additional interest rate increases in certain circumstances). In addition, the senior bridge facility included a covenant that obligated us to use commercially reasonable efforts to refinance the senior bridge facility as promptly as practicable.

Prior Senior Credit Facility. Prior to its termination on November 21, 2006, we had a $130 million revolving credit facility in place with Bank of America, N.A. (the prior senior credit facility). The prior senior credit facility included a $20 million sub-limit for letters of credit. The prior senior credit facility was replaced by the senior credit facility as of November 21, 2006. Advances under the prior senior credit facility were subject to a borrowing base based on our proved developed producing reserves, our proved developed non-producing reserves and proved undeveloped reserves. The borrowing base was subject to re-determination semi-annually at the sole discretion of the lender based on the reports of independent petroleum engineers in accordance with normal and customary natural gas and oil lending practices.

The prior senior credit facility bore interest at our option at either LIBOR plus 2.15% or the Bank of America, N.A. prime rate. We paid a commitment fee on the unused portion of the borrowing base amount equal to 1/8% per annum. The prior senior credit facility was collateralized by natural gas and oil properties representing at least 80% of the present discounted value of our proved reserves and by a negative pledge on any of our non-mortgaged properties.

Building Mortgage. On November 15, 2007, we entered into a note payable in the amount of $20 million with a lending institution which is fully secured by our downtown property. The mortgage bears interest at 6.08% ,and matures November 15, 2022. Payments of principal and interest in the amount of approximately $0.5 million are due on a quarterly basis through the maturity date. We expect to make payments of principal and interest on this note totaling $1.0 million and $1.1 million, respectively, over the next twelve months.

Convertible Preferred Stock

We have 2,184,286 shares of convertible preferred stock issued and outstanding. Each holder of our convertible preferred stock is entitled to quarterly cash dividends at the annual rate of 7.75% of the accreted value of its convertible preferred stock. At our option, we may choose to increase the accreted value of the convertible preferred stock in lieu of paying any quarterly cash dividend. The accreted value is $210 per share as of September 30, 2007. Each share of convertible preferred stock is currently convertible into approximately 10.2 shares of common stock at the option of the holder, subject to certain anti-dilution adjustments. In addition, beginning in the second quarter of 2008, we may convert all outstanding shares of convertible preferred stock at the same conversion rate if we have satisfied certain conditions.

Initial Public Offering

On November 9, 2007, we completed the initial public offering of our common stock. We sold 28,700,000 shares of SandRidge common stock, including 4,170,000 shares sold directly to an entity controlled by Tom L. Ward, at a price of $26 per share. We received net proceeds of approximately $705.4 million after deducting underwriting discounts of approximately $38.3 million and estimated offering expenses of approximately $2.5 million. In conjunction with the IPO, the underwriters were granted an option to purchase 3,679,500 additional shares of the our common stock. The underwriters fully exercised this option and purchased the additional shares on November 6, 2007. After deducting underwriting discounts of approximately $5.7 million, we received net proceeds of approximately $89.9 million from these additional shares. This offering generated total gross proceeds to us of approximately $841.8 million and total net proceeds of approximately $795.3 million to us after deducting total underwriting discounts of $44.0 million and other offering expenses estimated to be approximately $2.5 million. After the payment of offering expenses, we used a portion of the aggregate net proceeds to repay outstanding indebtedness under our senior credit facility as well as a note payable related to a recent acquisition. Funds remaining after these repayments will be used to fund future capital expenditures.

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Contractual Obligations

A summary of our contractual obligations as of September 30, 2007 is provided in the following table:

	Payments Due by Year (In thousands)						
	Remainder of 2007	2008	2009	2010	2011	After 2011	Total
Long-term debt	$ 3,629	$ 14,450	$ 15,664	$ 11,541	$ 406,220	$ 1,000,000	$ 1,451,504
Interest on term loan(1)	35,502	85,944	85,944	85,944	85,944	249,436	628,714
Firm transportation(2)	237	949	949	949	949	4,592	8,625
Operating leases	1,209	4,525	2,707	110	46		8,597
Third party drilling rig commitments(3)	5,946	8,325					14,271
Dispute settlement payments(4)		5,000	5,000	5,000	5,000		20,000
Asset retirement obligations		846	150	199	8,582	47,731	57,508
Total	$ 46,523	$ 120,039	$ 110,414	$ 103,743	$ 506,741	$ 1,301,759	$ 2,189,219

(1) Based on interest rates as of November 14, 2007.

(2) We entered into a firm transportation agreement with Questar Pipeline Company giving us guaranteed capacity on their pipeline for 10 MmBtu per day at an estimated charge of $0.9 million per year, with a total commitment of $9.1 million. In December 2006 we assigned our rights and obligations to a third party.

(3) Drilling contracts with third party drilling rig operators at specified day rates. All of our drilling rig contracts contain operator performance conditions that allow for pricing adjustments or early termination for operator nonperformance. Subsequent to September 30, 2007, the Company signed short-term contracts (approximately 100 days) for two additional rigs for total commitments of approximately $3.8 million.

(4) In January 2007, we settled a royalty interest dispute and agreed to pay five installments of $5 million each, plus interest commencing April 1, 2007. The remaining installments are due on July 1 of each year commencing July 1, 2008.

In connection with the NEG acquisition, we acquired restricted deposits aggregating $31.9 million. The restricted deposits represent bank trust and escrow accounts required to be set up by surety bond underwriters and certain former owners of a subsidiary on NEG s offshore properties. In accordance with requirements of MMS, the NEG subsidiary was required to put in place surety bonds or escrow agreements to provide satisfaction of its eventual responsibility to plug and abandon wells and remove structures when certain offshore fields are no longer in use. As part of the agreement with the surety bond underwriter or the former owners of the particular fields, bank trust and escrow accounts were set up and funded based on the terms of the escrow agreements. Certain amounts are required to be paid upon receipt of proceeds from production.

In connection with one of the escrow accounts, we are required to make quarterly deposits to the escrow accounts of $0.8 million. Additionally, for some of the offshore properties, we will be required to deposit additional funds in an escrow account, representing the difference between the required escrow deposit under the surety bond and actual escrow deposit balance at various points in time in the future. Aggregate payments to the escrow accounts are estimated as follows (in thousands):

Remainder of 2007	$ 800
2008	3,200
2009	3,200
2010	5,000
Thereafter	4,000
	$ 16,200

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Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make assumptions and prepare estimates that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities and revenues and expenses. We base our estimates on historical experience and various other assumptions that we believe are reasonable; however, actual results may differ. See Consolidated Financial Statements, Note 1 Summary of Organization and Significant Accounting Policies for a discussion of our significant accounting policies.

Proved Reserves. Over 97% of our reserves are estimated on an annual basis by independent petroleum engineers. Our estimates of proved reserves are based on the quantities of natural gas and oil which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. However, there are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future revenues, rates of production and timing of development expenditures, including many factors beyond our control. The estimation process is very complex and relies on assumptions and subjective interpretations of available geologic, geophysical, engineering and production data, and the accuracy of reserve estimates is a function of the quality and quantity of available data, engineering and geological interpretation and judgment. In addition, as a result of volatility and changing market conditions, commodity prices and future development costs will change from period to period, causing estimates of proved reserves to change, as well as causing estimates of future net revenues to change. For the years ended December 31, 2006 and 2005, we revised our proved reserves upward from prior years reports by approximately 26.6 Bcfe and 12.3 Bcfe and revised our proved reserves downward 18.5 Bcfe in 2004 due to proved undeveloped reserves that were determined to contain greater (or lesser) quantities than originally estimated, due to market prices at the end of the applicable period or from production performance indicating more (or less) reserves in place or larger (or smaller) reservoir size than initially estimated. Estimates of proved reserves are key components of our most significant financial estimates involving our rate for recording depreciation, depletion and amortization and our full-cost ceiling limitation. These revisions may be material and could materially affect our future depletion, depreciation and amortization expenses.

Method of accounting for natural gas and oil properties. Our natural gas and oil properties are accounted for using the full-cost method of accounting. All direct costs and certain indirect costs associated with the acquisition, exploration and development of natural gas and oil properties are capitalized. Exploration and development costs include dry hole costs, geological and geophysical costs, direct overhead related to exploration and development activities and other costs incurred for the purpose of finding natural gas and oil reserves. Amortization of natural gas and oil properties is provided using the unit-of-production method based on estimated proved natural gas and oil reserves. No gains or losses are recognized upon the sale or disposition of natural gas and oil properties unless the sale or disposition represents a significant quantity of natural gas and oil reserves, which would have a significant impact on the depreciation, depletion and amortization rate.

In accordance with full-cost accounting rules, capitalized cost are subject to a limitation. The capitalized cost of natural gas and oil properties, net of accumulated depreciation, depletion, and amortization, may not exceed the estimated future net cash flows from proved natural gas and oil reserves discounted at 10%, plus the lower of cost or fair market value of unproved properties as adjusted for related tax effects. The full-cost ceiling limitation is calculated using natural gas and oil prices in effect as of the balance sheet date and adjusted for basis or location differential, held constant over the life of the reserves. If capitalized costs exceed this limit (the ceiling limitation), the excess must be charged to expense. Once incurred, a write-down is not reversible at a later date. We did not have any adjustment to earnings due to the ceiling limitation for the periods presented herein.

Unevaluated Properties. The balance of unevaluated properties is comprised of capital costs incurred for undeveloped acreage, wells and production facilities in progress and wells pending determination, together with capitalized interest costs for these projects. These costs are initially excluded from our amortization base until the outcome of the project has been determined, or generally, until it is known whether proved reserves

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will or will not be assigned to the property. We assess all items classified as unevaluated property on a quarterly basis for possible impairment or reduction in value. We assess our properties on an individual basis or as a group if properties are individually insignificant. Our assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full-cost pool and are then subject to amortization. We estimate that substantially all of our costs classified as unproved as of the balance sheet date will be evaluated and transferred within a four-year period.

Asset Retirement Obligations. Asset retirement obligations represent the estimated future abandonment costs of tangible long-lived assets such as platforms, wells, service assets, pipelines and other facilities. We estimate the fair value of an asset s retirement obligation in the period in which the liability is incurred, if a reasonable estimate can be made. We employ a present value technique to estimate the fair value of an asset retirement obligation, which reflects certain assumptions, including an inflation rate, our credit-adjusted, risk-free interest rate, the estimated settlement date of the liability and the estimated current cost to settle the liability based on third party quotes and current actual costs. Changes in timing or to the original estimate of cash flows will result in changes to the carrying amount of the liability.

Revenue Recognition and Gas Balancing. Oil and natural gas revenues are recorded when title passes to the customer, net of royalties, discounts and allowances, as applicable. We account for oil and natural gas production imbalances using the sales method, whereby we recognize revenue on all oil and natural gas sold to our customers notwithstanding the fact that its ownership may be less than 100% of the oil and natural gas sold. Liabilities are recorded for imbalances greater than our proportionate share of remaining estimated oil and natural gas reserves.

We recognize revenues and expenses generated from daywork drilling contracts as the services are performed, since we do not bear the risk of completion of the well. Under footage and turnkey contracts, we bear the risk of completion of the well; therefore, revenues and expenses are recognized when the well is substantially completed. Under this method, substantial completion is determined when the well bore reaches the negotiated depth as stated in the contract. The duration of all three types of contracts range typically from 20 to 90 days. The entire amount of a loss, if any, is recorded when the loss is determinable. The costs of uncompleted drilling contracts include expenses incurred to date on footage or turnkey contracts, which are still in process at the end of the period.

We may receive lump-sum fees for the mobilization of equipment and personnel. Mobilization fees received and costs incurred to mobilize a rig from one market to another are recognized over the term of the related drilling contract. The contract terms are typically from 20 to 90 days.

Revenues of our midstream gas services segment are derived from providing supply, transportation, balancing and sales services for producers and wholesale customers on our natural gas pipelines, as well as other interconnected pipeline systems. Midstream gas services are primarily undertaken to realize incremental margins on gas purchased at the wellhead, and provide value-added services to customers. In general, natural gas purchased and sold by our midstream gas business is priced at a published daily or monthly index price. Sales to wholesale customers typically incorporate a premium for managing their transmission and balancing requirements. Revenues are recognized upon delivery of natural gas to customers and/or when services are rendered, pricing is determinable and collectibility is reasonably assured.

Revenue from sales of CO_2 is recognized when the product is delivered to the customer. We recognize service fees related to the transportation of CO_2 as revenue when the related service is provided.

Property, Plant and Equipment, Net. Other capitalized costs, including drilling equipment, natural gas gathering and processing equipment, transportation equipment and other property and equipment are carried at cost. Renewals and improvements are capitalized while repairs and maintenance are expensed. Depreciation of drilling equipment is recorded using the straight-line method based on estimated useful lives. Depreciation of other property and equipment is computed using the straight-line method over the estimated useful lives of the assets ranging from 3 to 39 years.

Realization of the carrying value of property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset including disposal value if any, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. An estimate of fair value is based on the best information available, including prices for similar assets. Changes in such estimates could cause us to reduce the carrying value of property and equipment.

When property and equipment components are disposed of, the cost and the related accumulated depreciation are removed from the accounts and any resulting gain or loss is generally reflected in operations.

Income Taxes. Deferred income taxes are provided on temporary differences between financial statement and income tax reporting. Temporary differences are differences between the amounts of assets and liabilities reported for financial statement purposes and their tax bases. Deferred tax assets are recognized for temporary differences that will be deductible in future years tax returns and for operating loss and tax credit carryforwards. Deferred tax assets are reduced by a valuation allowance if it is deemed more likely than not that some or all of the deferred tax assets will not be realized. Deferred tax liabilities are recognized for temporary differences that will be taxable in future years tax returns.

Derivative Financial Instruments. To manage risks related to increases in interest rates and changes in natural gas and oil prices, we enter into interest rate swaps and natural gas and oil futures contracts.

We recognize all of our derivative instruments as either assets or liabilities at fair value. The accounting for changes in the fair value (i.e., gains or losses) of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship, and further, on the type of hedging relationship. For those derivative instruments that are designated and qualify as hedging instruments, we designate the hedging instrument, based on the exposure being hedged, as either a fair value hedge or a cash flow hedge. For derivative instruments not designated as hedging instruments, the gain or loss is recognized in current earnings during the period of change. None of our derivatives were designated as hedging instruments during 2007, 2006 and 2005.

New Accounting Pronouncements

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements, which establishes a formal framework for measuring fair values of assets and liabilities in financial statements that are already required by U.S. generally accepted accounting principles (GAAP) to be measured at fair value. SFAS No. 157 clarifies guidance in FASB Concepts Statement (CON) No. 7 which discusses present value techniques in measuring fair value. No new fair value measurements are prescribed, and SFAS No. 157 is intended to codify the several definitions of fair value included in various accounting standards. However, the application of this Statement may change current practices for certain companies. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. We are currently evaluating the impact of adopting SFAS No. 157 on the financial statements.

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 (SFAS No. 159), which permits an entity to choose to measure certain financial assets and liabilities at fair value. SFAS No. 159 also revises provisions of SFAS No. 115 that apply to available-for-sale and trading securities. This statement is effective for fiscal years beginning after November 15, 2007. We are currently evaluating the impact of adopting SFAS No. 157 on the financial statements.

Effects of Inflation

The effect of inflation in the natural gas and oil industry is primarily driven by the prices for natural gas and oil. Increased commodity prices increase demand for contract drilling rigs and services, which supports higher drilling rig activity. This in turn affects the overall demand for our drilling rigs and the dayrates we can obtain for our contract drilling services.

Over the last three years, natural gas and oil prices have been more volatile, and during periods of higher utilization we have experienced increases in labor cost and the cost of services to support our drilling rigs.

During this same period, when commodity prices declined, labor rates did not return to the levels that existed before the increases. If natural gas prices increase substantially for a long period, shortages in support equipment (such as drill pipe, third-party services and qualified labor) may result in additional increases in our material and labor costs. These conditions may limit our ability to realize improvements in operating profits. How inflation will affect us in the future will depend on additional increases, if any, realized in our drilling rig rates and the prices we receive for our natural gas and oil.

Quantitative and Qualitative Disclosures About Market Risk

The discussion in this section provides information about the financial instruments we use to manage commodity price and interest rate volatility. All contracts are financial contracts, which are settled in cash and do not require the delivery of a physical quantity to satisfy settlement.

Commodity Price Risk. Our most significant market risk is the prices we receive for our gas and oil production, which can be highly volatile. In light of this historical volatility, we periodically have entered into, and expect in the future to enter into, derivative arrangements aimed at reducing the variability of gas and oil prices we receive for our production. We will from time to time enter into commodities pricing derivative instruments for a portion of our anticipated production volumes depending upon our management s view of opportunities under the then current market conditions. We do not intend to enter into derivative instruments that would exceed our expected production volumes for the period covered by the derivative arrangement. Our current credit agreement limits our ability to enter into derivatives transactions to 85% of expected production volumes from estimated proved reserves. Future credit agreements could require a minimum level of commodity price hedging.

We use, or may use, a variety of derivative instruments including collars and fixed-price swaps. These transactions generally require no cash payment upfront and are settled in cash at maturity. While this strategy may result in lower operating profits than if we were not party to these derivative instruments in times of high natural gas prices, we believe that the stabilization of prices and protection afforded us by providing a revenue floor for our production is very beneficial.

For natural gas derivatives, transactions are settled based upon the New York Mercantile Exchange price of natural gas at the Waha hub, a West Texas gas marketing and delivery center, on the final trading day of the month. Settlement for natural gas derivative contracts occurs in the month following the production month. Generally, our trade counterparties are affiliates of the financial institution that is a party to our credit agreement, although we do have transactions with counterparties that are not affiliated with this institution.

While we believe that the gas and oil price derivative arrangements we enter into are important to our program to manage price variability for our production, we have not designated any of our derivative contracts as hedges for accounting purposes. We record all derivative contracts on the balance sheet at fair value, which will be significantly affected by changes in gas and oil prices. We establish fair value of our derivative contracts by market price quotations of the derivative contract or, if not available, market price quotations of derivative contracts with similar terms and characteristics. When market quotations are not available, we will estimate the fair value of derivative contracts using option pricing models that management believes represent its best estimate. Changes in fair values of our derivative contracts that are not designated as hedges for accounting purposes are recognized as unrealized gains and losses in current period earnings. As a result, our

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current period earnings may be significantly affected by changes in fair value of our commodities derivative arrangements. The gain recognized in earnings, included in operating costs and expenses, for the nine months ended September 30, 2006 and 2007 was a gain of $16.2 million and $55.2 million, respectively.

At December 31, 2007, our open commodity derivative contracts consisted of the following:

Period	Commodity	Notional		Fix Price
Fixed price swap				
November 2007 - March 2008	Natural gas	1,520,000 MmBtu	$	8.51
November 2007 - June 2008	Natural gas	4,860,000 MmBtu	$	8.05
November 2007 - June 2008	Natural gas	9,720,000 MmBtu	$	8.20
January 2008	Natural gas	310,000 MmBtu	$	8.24
January 2008 - June 2008	Natural gas	3,640,000 MmBtu	$	7.99
January 2008 - June 2008	Natural gas	3,640,000 MmBtu	$	7.99
January 2008 - December 2008	Natural gas	3,660,000 MmBtu	$	8.23
January 2008 - December 2008	Natural gas	3,660,000 MmBtu	$	8.48
January 2008 - December 2008	Natural gas	3,660,000 MmBtu	$	9.00
April 2008 - June 2008	Natural gas	910,000 MmBtu	$	7.17
May 2008 - August 2008	Natural gas	2,460,000 MmBtu	$	8.38
July 2008	Natural gas	310,000 MmBtu	$	8.00
July 2008	Natural gas	310,000 MmBtu	$	8.02
July 2008 - September 2008	Natural gas	920,000 MmBtu	$	7.43
July 2008 - September 2008	Natural gas	920,000 MmBtu	$	7.49
July 2008 - September 2008	Natural gas	920,000 MmBtu	$	8.06
July 2008 - September 2008	Natural gas	920,000 MmBtu	$	8.07
July 2008 - September 2008	Natural gas	920,000 MmBtu	$	8.23
July 2008 - September 2008	Natural gas	920,000 MmBtu	$	8.36
July 2008 - December 2008	Natural gas	1,840,000 MmBtu	$	8.31
July 2008 - December 2008	Natural gas	1,840,000 MmBtu	$	8.35
August 2008	Natural gas	310,000 MmBtu	$	8.00
August 2008	Natural gas	310,000 MmBtu	$	8.07
September 2008	Natural gas	300,000 MmBtu	$	8.05
September 2008	Natural gas	300,000 MmBtu	$	8.10
October 2008 - December 2008	Natural gas	920,000 MmBtu	$	7.96
October 2008 - December 2008	Natural gas	1,840,000 MmBtu	$	8.00
October 2008 - December 2008	Natural gas	920,000 MmBtu	$	8.07
October 2008 - December 2008	Natural gas	920,000 MmBtu	$	8.11
October 2008 - December 2008	Natural gas	920,000 MmBtu	$	8.16
October 2008 - December 2008	Natural gas	920,000 MmBtu	$	8.32
October 2008 - December 2008	Natural gas	920,000 MmBtu	$	8.83
January 2009 - March 2009	Natural gas	900,000 MmBtu	$	8.56
January 2009 - March 2009	Natural gas	900,000 MmBtu	$	8.60
January 2009 - March 2009	Natural gas	900,000 MmBtu	$	8.65
January 2009 - March 2009	Natural gas	900,000 MmBtu	$	8.91
Collars				
January 2008 - June 2008	Crude oil	42,000 Bbls	$	50.00 - $83.35
July 2008 - December 2008	Crude oil	54,000 Bbls	$	50.00 - $82.60

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Period	Commodity	Notional	Fix Price	
Waha basis swap				
January 2008 - December 2008	Natural gas	10,980,000 MmBtu	$	(0.57)
January 2008 - December 2008	Natural gas	7,320,000 MmBtu	$	(0.585)
January 2008 - December 2008	Natural gas	7,320,000 MmBtu	$	(0.59)
January 2008 - December 2008	Natural gas	3,660,000 MmBtu	$	(0.595)
January 2008 - December 2008	Natural gas	3,660,000 MmBtu	$	(0.625)
January 2008 - December 2008	Natural gas	7,320,000 MmBtu	$	(0.635)
January 2008 - December 2008	Natural gas	7,320,000 MmBtu	$	(0.6525)
May 2008 - August 2008	Natural gas	2,460,000 MmBtu	$	(0.45)
June 2008 - August 2008	Natural gas	920,000 MmBtu	$	(0.4808)
September 2008 - December 2008	Natural gas	2,440,000 MmBtu	$	(0.7930)
January 2009 - December 2009	Natural gas	3,650,000 MmBtu	$	(0.47)
January 2009 - December 2009	Natural gas	3,650,000 MmBtu	$	(0.49)
January 2009 - December 2009	Natural gas	3,650,000 MmBtu	$	(0.4975)

These derivative instruments have not been designated as hedges.

Interest Rate Risk. We are subject to interest rate risk on our long-term fixed and variable interest rate borrowings. Fixed rate debt, where the interest rate is fixed over the life of the instrument, exposes us (i) to changes in market interest rates reflected in the fair value of the debt and (ii) to the risk that we may need to refinance maturing debt with new debt at a higher rate. Variable rate debt, where the interest rate fluctuates, exposes us to short-term changes in market interest rates as our interest obligations on these instruments are periodically redetermined based on prevailing market interest rates, primarily LIBOR and the federal funds rate.

The indebtedness evidenced by our other notes payable related to our drilling rig fleet and related oil field services equipment, Sagebrush Pipeline, insurance financing, and other equipment and vehicles and a portion of our term loan is a fixed-rate debt, which exposes us to cash-flow risk from market interest rate changes on these notes. The fair value of that debt will vary as interest rates change.

Borrowings under our senior credit facility and a portion of our term loan expose us to certain market risks. We use sensitivity analysis to determine the impact that market risk exposures may have on our variable interest rate borrowings. At September 30, 2007, borrowings outstanding under our senior credit facility totaled $400 million. Based on the approximately $350.0 million outstanding balance of the variable rate portion of our term loan at September 30, 2007, a one percent change in the applicable rate, with all other variables held constant, would result in a change in our interest expense of approximately $2.6 million for the nine months ended September 30, 2007.

In addition to commodity price derivative arrangements, we may enter into derivative transactions to fix the interest we pay on a portion of the money we borrow under our credit agreements. At September 30, 2007, we are not party to any interest rate swap instruments. Future interest rate derivative instruments, if any, are expected to be with affiliates of the financial institution that are party to our credit agreements.

BUSINESS

Overview

SandRidge is a rapidly expanding independent natural gas and oil company concentrating in exploration, development and production activities. We are focused on expanding our continuing exploration and exploitation of our significant holdings in an area of West Texas we refer to as the West Texas Overthrust, or WTO, a natural gas prone geological region where we have operated since 1986 that includes the Piñon Field and our South Sabino and Big Canyon prospects. We intend to add to our existing reserve and production base in this area by increasing our development drilling activities in the Piñon Field and our exploration program in other prospects that we have identified. As a result of our 2006 acquisitions, including the NEG acquisition, we have nearly tripled our net acreage position in the WTO since January 2006. We believe that we are the largest operator and producer in the WTO and have assembled the largest position in the area. We also operate significant interests in the Cotton Valley Trend in East Texas, the Gulf Coast area, the Gulf of Mexico and the Piceance Basin of Colorado.

We have assembled an extensive natural gas and oil property base in which we have identified over 4,500 potential drilling locations including over 2,600 in the WTO. As of June 30, 2007, our proved reserves were 1,174.0 Bcfe, of which 82% were natural gas and 97.5% of which were prepared by independent petroleum engineers. We had 1,469 gross (1,040 net) producing wells, substantially all of which we operate. As of September 30, 2007, we had interests in approximately 1,112,231 gross (763,032 net) natural gas and oil leased acres. We had 30 rigs drilling in the WTO as of September 30, 2007.

We also operate businesses that are complementary to our primary exploration, development and production activities, which provides us with operational flexibility and an advantageous cost structure. We own a fleet of 32 drilling rigs, three of which are currently being retrofitted. In addition, we are a party to a joint venture that owns an additional twelve rigs, eleven of which are currently operating. We own related oil field services businesses, gas gathering and treating facilities and a marketing business. We capture and supply CO_2 to support our tertiary oil recovery projects undertaken by us or third-parties. We use this CO_2 in our own tertiary oil recovery projects and market it to third-parties for use in tertiary oil recovery projects. These assets are primarily located in our primary operating area in West Texas.

We expanded our management team significantly in 2006. Tom L. Ward, the co-founder and former President and Chief Operating Officer of Chesapeake Energy Corporation (Chesapeake), purchased a significant ownership interest in us in June 2006 and joined us as Chief Executive Officer and Chairman of the Board. During Mr. Ward s 17 year tenure at Chesapeake, Chesapeake became one of the most active onshore drillers in the United States. From 1998 to 2005, Chesapeake drilled over 6,500 wells. Since Mr. Ward joined us, we have added eight new executive officers, substantially all of which have experience at public exploration and production companies. In July 2006, we relocated our corporate headquarters to Oklahoma City to take advantage of the broader market of experienced energy professionals. We have also added key professionals in exploration, operations, land, accounting and finance.

Our estimated capital expenditures for 2008 of approximately $1,250 million include $1,100 million allocated to exploration and development (including land and seismic acquisitions and our tertiary recovery operations), $50 million allocated to drilling and oil field services and $100 million allocated to midstream gas operations. Approximately $622 million of our capital expenditures are to be spent in our Piñon Field development and our exploratory projects in the WTO (including land and seismic acquisitions). Under this capital budget, we plan to drill approximately 440 gross wells in 2008. The actual number of wells drilled in our drilling program and the amount of our 2008 capital expenditures will be dependent upon market conditions, availability of capital and drilling and production results.

The NEG Acquisition

On November 21, 2006, we acquired all of the outstanding membership interests of NEG from a subsidiary of American Real Estate Partners, L.P., or AREP, for approximately $990.4 million in cash, the assumption of $300 million in debt, the receipt of cash of $21.1 million, and the issuance of 12,842,000 shares

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of our common stock valued at approximately $231.2 million. NEG owned core assets in the Val Verde and Permian Basins of West Texas, including overlapping or contiguous interests in the properties that we own in the WTO. Based on reserve reports prepared as of June 30, 2006 by DeGolyer & MacNaughton and Netherland, Sewell & Associates, Inc., the estimated proved reserves of NEG were 519.7 Bcfe.

Pursuant to our acquisition agreement with AREP, we agreed to acquire NEG including all of the membership interests in NEG Holding LLC, but excluding any investment in NEGI. Prior to our acquisition of NEG:

NEG acquired the remaining 50% membership interest in NEG Holding LLC that NEG did not already own by exercising an option it had to redeem this interest from NEGI for fair value; and

NEG distributed to its former parent, a subsidiary of AREP, all of its investment in National Energy Group, Inc. (NEGI), consisting of 50.1% of the outstanding shares of NEGI capital stock and $148 million of outstanding 103/4% senior notes due from NEGI.

As a result, when we acquired NEG, it owned 100% of the membership interests of NEG Holding LLC and had no interest or investment in NEGI. The operating oil and gas assets of NEG are held in wholly-owned operating subsidiaries of NEG, including NEG Holding LLC.

We have included elsewhere in this prospectus the combined financial statements of NEG and subsidiaries, excluding NEGI and the 103/4% senior notes due from NEGI, but including NEGI s 50% membership interest in NEG Holding LLC for certain periods and dates prior to our acquisition of NEG. Because of the changes effected at NEG prior to our acquisition, we believe that these combined NEG financial statements provide a clearer and more relevant presentation for our investors of the financial condition and results of operations of the acquired business of NEG than consolidated financial statements of NEG for these periods and dates.

Our Strategy

Our primary objective is to achieve long-term growth and maximize stockholder value over multiple business cycles by pursuing the following strategies:

Grow Through Exploration and Aggressive Drilling and Development of Existing Acreage. We expect to generate long-term reserve and production growth by exploring and aggressively drilling and developing our large acreage position. Our primary exploration and development focus will be in the WTO, where we have identified over 2,600 potential drilling locations and had 30 rigs operating as of September 30, 2007. We have also identified 566 potential drilling locations in the Cotton Valley Trend in East Texas and had six rigs running in this region at the end of 2007.

Apply Technological Improvements to Our Exploration and Development Program. We intend to enhance our drilling success rate and completion efficiency with improved 3-D seismic acquisition and interpretation technology and applying advanced drilling, completion and production methods in the exploration and development of our large acreage position in the WTO. We believe that this area is under-explored with modern technology and that the application of this technology has the potential to result in a higher overall drilling success rate and higher initial production rates and ultimate well recoveries, thereby improving overall economics.

Seek Opportunistic Acquisitions in Our Core Geographic Area. Since January 2006, through acquisitions and leasing activities, we have nearly tripled our net acreage position in the WTO. We intend to continue to seek other opportunities to optimize and enhance our exploratory acreage position in the WTO and other strategic areas.

Reduce Costs, Enhance Returns and Maintain Operating Flexibility by Controlling Drilling Rigs and Midstream Assets. Our rig fleet enables us to aggressively develop our own acreage while maintaining the flexibility of a third-party contract drilling business. We plan to capitalize on opportunities to utilize our rigs primarily in the WTO, where we had 30 of our rigs drilling our own wells as of June 30, 2007.

By controlling our fleet of drilling rigs and gathering and treating assets, we believe we will be able to better control overall costs and maintain a high degree of operational flexibility.

Capture and Utilize CO_2 for Tertiary Oil Recovery. We intend to capitalize on our access to CO_2 reserves and CO_2 flooding expertise to pursue enhanced oil recovery in mature oil fields in West Texas. By utilizing this CO_2 in our own tertiary recovery projects, we expect to recover additional oil that would have otherwise been abandoned following traditional waterfloods.

Competitive Strengths

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

Large Asset Base with Substantial Drilling Inventory. Our producing properties are characterized by long-lived predominantly natural gas reserves with established production profiles. Our estimated proved reserves of 1,174.0 Bcfe as of June 30, 2007 had a proved reserves to production ratio of approximately 19 years. Our core area of operations in the WTO has expanded to 581,961 gross (480,721 net) acres as of September 30, 2007. We have identified over 2,600 potential drilling locations in the WTO and believe that we will be able to expand the number of drilling locations in the remainder of the WTO through exploratory drilling and our use of 3-D seismic technology.

Geographically Concentrated Exploration and Development Operations. We intend to focus our drilling and development operations in the near term on the WTO to fully exploit this unique geological area. The WTO was created by the collision of the ancestral North and South American continents, which fractured and thrust the reservoir rock to come to rest in repeating layers. We believe the geological environment of the WTO and the height of the prospective pay zones create opportunities for significant conventional accumulations of natural gas and oil. To a lesser extent, we will also focus on the highly prolific Cotton Valley Trend in East Texas. This geographic concentration allows us to establish economies of scale in both drilling and production operations to achieve lower production costs and generate increased cash flows from our producing properties. We believe our concentrated acreage position will enable us to organically grow our reserves and production for the next several years.

Experienced Management Team Focused on Delivering Long-term Stockholder Value. During 2006, we significantly expanded our management team when Tom L. Ward, co-founder and former president of Chesapeake, purchased a significant interest in us and became our Chairman and Chief Executive Officer. We also hired a new chief financial officer and three additional executive vice presidents. Our nine executive officers and 27 senior executives average over 23 years of experience working in or servicing the natural gas and oil industry. Our management team, board of directors and employees owned over 35% of our capital stock on a fully-diluted basis as of November 30, 2007, which we believe aligns their objectives with those of our stockholders.

High Degree of Operational Control. We operate over 95% of our production in the WTO, East Texas and the Gulf Coast area, which permits us to manage our operating costs and better control capital expenditures and the timing of development and exploitation activities.

Large Modern Fleet of Drilling Rigs. We own a fleet of 32 drilling rigs, three of which are currently being retrofitted. In addition, we are a party to a joint venture that owns an additional twelve rigs, eleven of which are currently operating. By controlling a large, modern and more efficient drilling fleet, we can develop our existing reserves and explore for new reserves on a more economic basis.

Our Businesses and Primary Operations

Exploration and Production

We explore for, develop and produce natural gas and oil reserves, with a focus on increasing our reserves and production in the WTO. We operate substantially all of our wells in the WTO. We also have significant

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operated leasehold positions in the Cotton Valley Trend in East Texas and the Gulf Coast area, as well as other non-core operating areas.

The following table identifies certain information concerning our exploration and production business as of September 30, 2007 unless otherwise noted:

	Estimated Net Proved Reserves (Bcfe)(1)	PV-10 (in millions)(1)(2)	Daily Production (Mmcfe/d)(3)	Proved Reserves/ Production(1)	Gross Acreage	Net Acreage	Number of Identified Potential Drilling Locations(1)
Area							
WTO	648.3	$ 1,190.9	69.1	25.7(4)	581,961	480,721	2,658
East Texas	156.3	310.2	26.3	16.3	48,606	32,557	566
Gulf Coast	105.7	416.4	44.2	6.6	53,464	34,765	51
Other:							
Gulf of Mexico	57.3	176.7	17.2	9.1	73,614	36,770	82
Other West Texas	27.0	111.2	7.8	9.5	23,059	22,140	68
PetroSource	120.8	243.8	1.5	220.6	9,064	8,195	47
Piceance Basin	10.5	11.8	0.9	32.0	40,334	15,686	828
Other	48.1	110.5	9.7	13.6	282,129	132,198	273
Total	1,174.0	$ 2,558.8	176.7	18.2	1,112,231	763,032	4,573

(1) Estimated net proved reserves, PV-10 and identified potential drilling locations are as of June 30, 2007.

(2) PV-10 generally differs from Standardized Measure of Discounted Net Cash Flows, or Standardized Measure, which is measured only at fiscal year end, because it does not include the effects of income taxes on future net revenues. For a reconciliation of PV-10 to Standardized Measure as of December 31, 2006, see Summary Historical Operating and Reserve Data. Our Standardized Measure was $1,440.2 million at December 31, 2006.

(3) Represents average daily net production for the third quarter 2007.

(4) Our proved reserves to production ratio in the WTO is significantly higher than our other areas of operation because of the high volume of our proved undeveloped reserves in this area. We expect this ratio to decrease as our production in the WTO increases.

West Texas Overthrust (WTO)

We have drilled and developed natural gas in the WTO since 1986. This area is located in Pecos and Terrell Counties in West Texas and is associated with the Marathon-Ouachita fold and thrust belt that extends east-northeast across the United States into the Appalachian Mountain Region. The WTO was created by the collision of the ancestral North American and South American continents resulting in source rock and reservoir rock, including potential hydrocarbon traps, becoming thrusted upon one another in multiple layers (imbricate stacking) along the leading edge of the WTO. The collision and thrusting resulted in the reservoir rock becoming highly fractured, increasing the likelihood of conventional natural gas and oil accumulations in the reservoir rock and creating a unique geological setting in North America.

The primary reservoir rocks in the WTO range in depth from 2,000 to 10,000 feet and range in geologic age from the Permian to the Devonian. The imbricate stacking of these conventional gas-prone reservoirs provides for multi-pay exploration and development opportunities. Despite this, the WTO has historically been largely under-explored due primarily to the remoteness and lack of infrastructure in the region, as well as historical limitations of conventional subsurface geological and geophysical methods. However, several fields including our prolific Piñon Field have been discovered. These fields have produced more than 255 Bcfe from less than 410 wells through September 30, 2007. We believe our access to and control of the necessary

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infrastructure combined with application of modern seismic techniques will allow us to identify further exploration and development opportunities in the WTO.

In May 2007, we began the first phase of 3-D seismic data acquisition in the WTO. This is the first of six phases planned over the next three years to acquire 1,300 square miles of modern 3-D seismic data in the WTO. We believe this enhanced 3-D seismic program may identify structural details of potential reservoirs, thus lowering risk of exploratory drilling and improving completion efficiency. The first two phases of the seismic program covered 360 square miles and completed in 2007.

We have aggressively acquired leasehold acreage in the WTO, nearly tripling our position since January 2006. As of September 30, 2007 we owned 581,961 gross (480,721 net) acres in the WTO, substantially all of which are along the leading edge of the WTO.

Piñon Field. The Piñon Field, located in Pecos County, is our most significant producing field, and accounts for 55% of our proved reserve base as of June 30, 2007. The Piñon Field lies along the leading edge of the WTO. The primary reservoirs are the Wolfcamp sands (average depth of 2,500 to 3,500 feet), the Tesnus sands (average depth of 3,700 to 4,750 feet), the Upper Caballos chert (average depth of 5,500 feet), and the Lower Caballos chert (average depth of 7,300 to 10,000 feet).

As of June 30, 2007, our estimated proved natural gas and oil reserves in the Piñon Field were 648.3 Bcfe, 66% of which were proved undeveloped reserves. This field has produced more than 205 Bcfe through September 30, 2007 and currently produces in excess of 118 gross Mmcfe per day.

Our interests in the Piñon Field include 351 producing wells as of September 30, 2007. We had an 84.4% average working interest in the producing area of Piñon Field and were running 30 drilling rigs in the Piñon Field as of September 30, 2007. As of June 30, 2007, we have identified over 2,600 potential well locations in the Piñon Field, including 406 proved undeveloped drilling locations.

West Texas Overthrust Prospects. Through our exploratory drilling program, we have identified two prospect areas in the WTO, the South Sabino Prospect and the Big Canyon Prospect areas:

> *South Sabino Prospect Area.* The South Sabino prospect area is located approximately twelve miles east of the Piñon Field. We have drilled two wells which have encountered the Caballos chert and hydrocarbons in zones less than 7,000 feet deep. Those wells were selected using 2-D seismic and limited subsurface well control. The wells appear to be on trend with the Piñon Field and are structurally higher against one of several thrust faults that make up the WTO. We began the first phase of our 3-D seismic program in this area in 2007.
>
> *Big Canyon Prospect Area.* Located approximately 20 miles east of the Piñon Field along the WTO, this prospect area represents potential opportunities for future development. The key well, Big Canyon Ranch 106-1, was drilled by a third party to a depth of 24,075 feet and was abandoned in December 1993 after testing gas from the Tesnus sands and Caballos chert.

West Texas Overthrust Development. The following table provides information concerning development in the WTO:

Estimated Net PUD	Estimated Gross PUD	Gross PUD	Total Gross	Gross 2007	2007 Capital Expenditures	2006 Year	Rigs Working

Reserves (Bcfe)(1)	Reserves (Bcfe)(1)	Drilling Locations(1)	Drilling Locations(1)	Drilling Locations	Budget (in millions)(2)	End Rigs Working	at 3Q 2007 End
431.1	675.2	406	2,658	207	$ 537	9	30

(1) As of June 30, 2007.

(2) Excludes capital expenditures related to land and seismic acquisitions.

East Texas Cotton Valley Trend

We own significant natural gas and oil interests in the natural gas bearing Cotton Valley Trend in East Texas, which covers parts of East Texas and Northern Louisiana. We held interests in 48,606 gross (32,557 net) acres in East Texas as of June 30, 2007. At September 30, 2007, our estimated net proved reserves in East Texas were 156.3 Bcfe, with net production of approximately 26.8 Mmcfe per day. We intend to target the tight sand reservoirs of the Cotton Valley, Pettit and Travis Peak formations at depths of 6,500 to 10,500 feet. These sands are typically distributed over a large area, which has led to a near 100% success rate in this area. Due to the tight nature of the reservoirs, significant hydraulic fracture stimulation is required to obtain commercial production rates and efficiently drain the reservoir. Production in this area is generally characterized as long-lived, with wells having high initial production and decline rates that stabilize at lower levels after several years. Moreover, area operators continue to focus on infill development drilling as many areas have been down spaced to 80 acres per well, with some areas down spaced to as little as 40 acres per well. Recently, operators have begun drilling horizontal wells and we are monitoring their success. Thirty-seven wells have been drilled in the nine months of 2007. We had six rigs running in this region at the end of 2007.

Gulf Coast

We own natural gas and oil interests in 53,464 gross (34,765 net) acres in the Gulf Coast area as of September 30, 2007, which encompasses the large coastal plain from the southernmost tip of Texas through the southern portion of Louisiana. As of June 30, 2007, our estimated net proved reserves in the Gulf Coast area were 105.7 Bcfe, with net production of approximately 35.0 Mmcfe per day. This is a predominantly gas prone, multi-pay, geologically complex area with significant faulting and compartmentalized reservoirs where 3-D seismic and other advanced exploration technologies are critical to our efforts. This area is comprised of sediments ranging from Cretaceous through Tertiary age and is productive from very shallow depths of several thousand feet to depths in excess of 18,000 feet. We target shallower geological formations such as the Frio and the Miocene, as well as deeper horizons such as Wilcox and Vicksburg. Operations in this area are generally characterized as being higher risk and higher potential than in our other core areas, with successful wells typically having higher initial production rates with steeper declines and shorter production lives. Drilling cost per well also tends to be significantly higher than in our other areas due to the increased depth and complexity of wellbore conditions.

Other Areas

Gulf of Mexico. We own natural gas and oil interests in 73,614 gross (36,770 net) acres in State and federal waters off the coast of Texas and Louisiana as of September 30, 2007. At June 30, 2007 our estimated net proved reserves were 57.3 Bcfe, with net production of approximately 20.5 Mmcfe per day for the month of June 2007. The water depth ranges from 30 feet to 1,100 feet and activity extends from the coast to more than 100 miles offshore. The Gulf of Mexico is one of the premier producing basins in the United States and is an area where we have achieved value-added growth through exploitation and exploration. Our production will range in depth from several thousand feet to in excess of 17,000 feet. The reservoir rocks range in age from the Plio-Pleistocene through the Oligocene. Typical Gulf of Mexico reservoirs have high porosity and permeability and wells historically flow at prolific rates. Overall, the Gulf of Mexico is known as an area of high quality 3-D seismic acquisition. Our major areas of activity will include the blocks in East Breaks and High Island areas that are located off the Texas coast, and the East Cameron area located off the Louisiana coast. In most cases in this area we own non-operating interests with larger companies such as Chevron Corporation, BP plc and Apache Corporation. We are currently evaluating our future drilling plans and intend to manage our investment in this area to maximize returns without significantly increasing future capital expenditures.

Piceance Basin. The Piceance Basin in northwestern Colorado is a sedimentary basin consisting of multiple productive sandstone formations in one of the country s most prolific natural gas regions. We entered the Piceance Basin in 1993 with the purchase of leasehold interests predominantly located on federal lands. We acquired this position in order to utilize the experience we had gained in underbalanced drilling and foam fracture simulations in West Texas. Initially, development of these natural gas reserves was limited due to high drilling costs and complex completion requirements. However, new drilling and completion technologies now enable successful development in this area.

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We are currently evaluating wells we have drilled, but not completed, on the western portion of our acreage block. At September 30, 2007, we had identified 828 potential drilling locations on the eastern portion of our 40,334 gross (15,686 net) acres.

Other West Texas. Our other non-tertiary West Texas assets include our Brooklaw field and the Goldsmith Adobe Unit in the Permian Basin. As of September 30, 2007, we own 23,059 gross (22,140 net) acres in these prospects. As of June 30, 2007, our estimated net proved reserves were 27.0 Bcfe. We have identified 68 potential drilling locations in these fields, including 56 proved undeveloped locations.

Other. We own interests in properties in the Arkoma and Anadarko Basins and other non-strategic areas. As of September 30, 2007, we hold interests in 282,129 gross (132,198 net) leasehold and option acres in these non-strategic areas.

Tertiary Oil Recovery

Wellman Unit. The Wellman Unit is part of our tertiary oil recovery operations. The Wellman Field, located in Terry County, was discovered in 1950 and produces from the Canyon Reef limestone formation of Permian age from an average depth of 9,500 feet. The Wellman Unit is on the western edge of the Horseshoe Atoll, a geologic feature in the northern part of the Midland Basin. There are approximately 110 separate fields that are contained within this feature, including seven existing CO_2 floods. The Wellman Unit covers approximately 2,120 acres, 1,200 of which are well-suited for both water and CO_2 floods. The Wellman Field has been partially CO_2 flooded and water flooded to produce 79.9 Mmboe to date. We recently re-initiated injection of CO_2, and plan to average 30.9 Mmcf per day over the next 10 years. As of June 30, 2007, net proved reserves attributable to the Wellman Unit were 9.3 Mmboe. We also own a CO_2 recycling plant at this unit with a capacity of 28 Mmcf per day. The plant includes 6,000 horsepower of CO_2 compression and 4,850 horsepower of processing compression, which is sufficient to handle the recycling of the CO_2 that will be produced in association with the production of these reserves.

George Allen Unit. The George Allen Unit, located in Gaines County, covers 800 gross acres in the George Allen Field and produces from the San Andres formation from an average depth of 4,950 feet, in the George Allen Field. An additional 320 acres adjacent to the unit to the south have also been leased. The field is located within the greater Wasson area which contains seven active CO_2 floods including the largest in the world, the Denver Unit. The George Allen Unit has produced 0.5 Mmboe to date, but it also contains a significant transition zone which has been proven to be a tertiary oil target at the nearby Denver Unit. As of June 30, 2007, net proved reserves attributable to the George Allen Unit were 8.2 Mmboe.

South Mallet Unit. The South Mallet Unit, located in Hockley County, covers 3,540 gross acres in the Slaughter/Levelland Field complex and produces from the San Andres formation from an average depth of 5,000 feet. These fields are some of the largest in West Texas and currently have ten active CO_2 floods and four more at various stages of readiness. The South Mallet Unit has produced 27.8 Mmboe to date. We plan to begin injection of CO_2 in 2009, and we expect to reach an injection rate of approximately 7,100 Mcf per day by the beginning of 2010. As of June 30, 2007, net proved reserves attributable to the South Mallet Unit were 2.5 Mmboe.

Jones Ranch Area. Several miles west of the George Allen Unit, in Gaines County, PetroSource has acquired various leases in the Jones Ranch Area. These leases produce from various depths and formations from approximately 2,400 gross acres. We are evaluating these leases for both conventional development and tertiary potential.

Proved Reserves

The following tables present our historical estimated net proved natural gas and oil reserves and the present value of our estimated proved reserves as of December 31, 2005 and 2006 and June 30, 2007. The PV-10 and Standardized Measure shown in the table are not intended to represent the current market value of our estimated market value or our estimated natural gas and oil reserves. At June 30, 2007 approximately 62% of our proved reserves were proved undeveloped reserves. Based on our current drilling schedule, we estimate that 97% of our current proved undeveloped reserves will be developed by 2011 and all of our current proved undeveloped reserves will be developed by 2012.

Netherland, Sewell & Associates, Inc., independent oil and gas consultants, have prepared the reports of proved reserves of natural gas and crude oil for our net interest in oil and gas properties, which constitute approximately 92% of our total proved reserves as of December 31, 2006 and 87.2% of our total proved reserves as of June 30, 2007. DeGolyer and MacNaughton prepared the reports of proved reserves for PetroSource, which constitute approximately 7% of our total proved reserves as of December 31, 2006 and 10.3% of our total proved reserves as of June 30, 2007. Netherland, Sewell & Associates, Inc. and DeGolyer and MacNaughton prepared independent engineering reports for 97.5% of our total reserves represented by SandRidge on June 30, 2007 and are included exactly as represented by the respective firms. The remaining 2.5% of the proved reserves were estimated internally by us.

	At December 31, 2005	At December 31, 2006	At June 30, 2007
Estimated Proved Reserves(1)			
Natural Gas (Bcf)(2)	237.4	850.7	967.6
Oil (MmBbls)	10.4	25.2	34.4
Total (Bcfe)	300.0	1,001.8	1,174.0
PV-10 (in millions)	$ 733.3(3)	$ 1,734.3(3)	$ 2,558.8(3)
Standardized Measure of Discounted Net Cash Flows (in millions)(4)	$ 499.2	$ 1,440.2	n/a(5)

(1) Our estimated proved reserves and the future net revenues, PV-10, and Standardized Measure of Discounted Net Cash Flows were determined using end of the period prices for natural gas and oil that we realized as of December 31, 2005, December 31, 2006 and June 30, 2007, which were $8.40 per Mcf of natural gas and $54.04 per barrel of oil at December 31, 2005, $5.64 per Mcf of natural gas and $57.75 per barrel of oil at December 31, 2006, and $6.70 per Mcf of natural gas and $63.78 per barrel of oil at June 30, 2007.

(2) Given the nature of our natural gas reserves, a significant amount of our production, primarily in the WTO, contains natural gas high in CO_2 content. These figures are net of volumes of CO_2 in excess of pipeline quality specifications.

(3) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved natural gas and oil reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash flows and using pricing assumptions in effect at the end of the period. PV-10 differs from Standardized Measure of Discounted Net Cash Flows because it does not include the effects of income taxes and other items on future net revenues. Neither PV-10 nor Standardized Measure represent an estimate of fair market value of our natural gas and oil properties. PV-10 is used by the industry and by our management as an arbitrary reserve asset value measure to compare against past

reserve bases and the reserve bases of other business entities that are not dependent on the taxpaying status of the entity. The following tables provide a reconciliation of our Standardized Measure to PV-10:

	At December 31,	
	2005	2006
	(In millions)	
Standardized Measure of Discounted Net Cash Flows	$ 499.2	$ 1,440.2
Present value of future income tax and other discounted at 10%	234.1	294.1
PV-10	$ 733.3	$ 1,734.3

(4) The Standardized Measure of Discounted Net Cash Flows represents the present value of estimated future cash inflows from proved natural gas and oil reserves, less future development and production costs, and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized Measure differs from PV-10 because Standardized Measure includes the effect of future income taxes and other items.

(5) Standardized Measure of Discounted Net Cash Flows is only calculated at fiscal year end under applicable accounting rules.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (i) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (ii) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Estimates of proved reserves do not include the following:

oil that may become available from known reservoirs but is classified separately as indicated additional reserves;

crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;

crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and

crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Of our total proved reserves at June 30, 2007, 20.1 million barrels of oil equivalent, or 10.3% of our total proved reserves, are attributable to our tertiary oil recovery projects using CO_2 injection. Our reserve report of June 30, 2007 estimates total future costs of recovering proved reserves from tertiary oil recovery projects, including estimated capital costs and taxes, of approximately $30.04 per barrel of oil equivalent.

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Production and Price History

The following tables set forth information regarding our net production of oil, natural gas and natural gas liquids and certain price and cost information for each of the periods indicated. Because of the relatively high volumes of CO_2 produced with natural gas in certain areas of the WTO, our reported sales and reserves volumes and the related unit prices received for natural gas in these areas are reported net of CO_2 volumes stripped at the gas plants. The gas plant fees for removing CO_2 for our high CO_2 natural gas have been taken into account in our lease operating expenses as processing and gathering fees. In all other areas, natural gas sales are delivered to sales points with CO_2 levels within pipeline specifications and thus are included in sales and reserves volumes.

	Year Ended December 31,			Nine Months Ended September 30,	
	2004	2005	2006	2006	2007
Production Data:					
Natural Gas (Mmcf)	6,708	6,873	13,410	6,856	35,148
Oil (MBbls)	37	72	322	70	1,441
Combined Equivalent Volumes (Mmcfe)	6,930	7,305	15,342	7,275	43,793
Average Daily Combined Equivalent Volumes (Mmcfe/d)	18.9	20.0	42.0	27	160

	Year Ended December 31,			Nine Months Ended September 30,	
	2004	2005	2006	2006	2007
Average Prices(1):					
Natural Gas (per Mcf)	$ 4.43	$ 6.54	$ 6.19	$ 6.14	$ 6.56
Oil (per Bbl)	$ 34.03	$ 48.19	$ 56.61	$ 61.89	$ 61.67
Combined Equivalent (per Mcfe)	$ 4.47	$ 6.63	$ 6.60	$ 6.38	$ 7.30

(1) Reported prices represent actual prices for the periods presented and do not give effect to hedging transactions.

	Year Ended December 31,			Nine Months Ended September 30,	
	2004	2005	2006	2006	2007
Expenses per Mcfe:					
Lease operating expenses:					
Transportation	$ 0.14	$ 0.16	$ 0.22	$ 0.14	$ 0.15
Processing and gathering(1)	0.39	0.42	0.37	0.33	0.30
Other lease operating expenses	0.94	1.64	1.70	2.50	1.32
Total lease operating expenses	$ 1.48	$ 2.22	$ 2.29	$ 2.97	$ 1.77
Production taxes	$ 0.36	$ 0.43	$ 0.30	$ 0.35	$ 0.28

(1) Includes costs attributable to gas treatment to remove CO_2 and other impurities from our high CO_2 natural gas.

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Productive Wells

The following table sets forth information at September 30, 2007, relating to the productive wells in which we owned a working interest as of that date. Productive wells consist of producing wells and wells capable of producing, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest, and net wells are the sum of our fractional working interests owned in gross wells.

Area	Gross	Net
WTO	409	344
East Texas	163	150
Gulf Coast	198	120
Other:		
Gulf of Mexico	66	42
Other West Texas	265	257
PetroSource	9	7
Piceance Basin	45	16
Other	368	145
Total	1,523	1,081

Developed and Undeveloped Acreage

The following table sets forth information at September 30, 2007:

	Developed Acreage(1)		Undeveloped Acreage(2)	
Area	Gross(3)	Net(4)	Gross(3)	Net(4)
WTO	11,741	8,854	570,220	471,867
East Texas	29,084	25,817	19,522	6,740
Gulf Coast	39,438	24,678	14,026	10,087
Other:				
Gulf of Mexico	73,614	36,770		
Other West Texas	13,680	13,544	9,379	8,598
PetroSource	9,064	8,195		
Piceance Basin	1,800	451	38,534	15,234
Other	84,258	41,770	197,871	90,428
Total	262,679	160,079	849,552	602,953

(1) Developed acres are acres spaced or assigned to productive wells.

(2) Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

(3) A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

(4) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Many of the leases comprising the acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production. We generally have been able to obtain extensions of the primary terms of our federal leases when we have been unable to obtain drilling permits due to a pending Environmental Assessment, Environmental Impact Statement or related legal challenge. The following table sets forth as of September 30, 2007 the expiration periods of the gross and net acres that are subject to leases in the acreage summarized in the above table.

	Acres Expiring	
Twelve Months Ending	**Gross**	**Net**
December 31, 2007		
December 31, 2008	46,068	35,074
December 31, 2009	165,302	134,500
December 31, 2010 and later	564,843	395,187
Other(1)	336,018	198,301
Total	1,112,231	763,062

(1) Leases remaining in effect until the cessation of development efforts or cessation of production on the developed portion of the particular lease.

Drilling Results

The following table sets forth information with respect to wells we completed during the periods indicated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons, regardless of whether they produce a reasonable rate of return.

	Year Ended December 31, 2006		Nine Months Ended September 30, 2007	
	Gross	**Net**	**Gross**	**Net**
Development:				
Productive	82	50.8	181	130.8
Dry	5	2.5	3	2.3
Exploratory:				
Productive	19	13.0	2	1.5
Dry	6	5.0	3	2.5
Total:				
Productive	101	63.8	183	132.3
Dry	11	7.5	6	4.8

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Drilling Rigs

The following table sets forth information with respect to the drilling on our acreage as of the periods indicated.

	As of December 31, 2006		As of September 30, 2007	
Area	**Owned(1)**	**Third Party**	**Owned(1)**	**Third Party**
WTO	9		26	4
East Texas		2		6
Gulf Coast		1		
Other	1		2	
Total	10	3	28	10

(1) Includes both rigs owned by Lariat, our wholly owned subsidiary, and by Larclay, a joint venture.

Marketing and Customers

Through Integra Energy, our subsidiary, we market our natural gas production in accordance with standard industry practices. Each month we develop a portfolio of natural gas sales by arranging for a percentage of Integra Energy s natural gas to be sold on a first of the month index price basis with the remaining volume sold on a daily swing basis at current market rates. Most of the natural gas is sold on a month-to-month basis, and any longer term or evergreen agreements that we are subject to provide pricing provisions that allow us to receive monthly market area based prices. During the year ended December 31, 2006, we sold natural gas to 20 different purchasers.

Our top five natural gas purchasers of our WTO production for the nine months ended September 30, 2007 and each company s approximate percentage of total sales during that period are listed below:

Gas Purchasers	**%**
ANP Funding I, LLC	26.4%
Magnus Energy Marketing, Ltd.	17.8%
Atmos Energy Corporation	13.9%
El Paso Industrial Energy, LP	10.4%
Southern Union Gas Services, Ltd.	10.1%

Title to Properties

As is customary in the natural gas and oil 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. In addition, prior to completing an acquisition of producing natural gas and oil 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. To date, 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 natural gas and oil industry. However, we have drilled wells in the Piceance Basin, which are subject to litigation that may affect that property. Please read Legal Proceedings. Our natural gas and oil properties are subject to customary royalty and other interests, liens for current taxes and other burdens which we believe do not materially interfere with the use of or affect our carrying value of the properties.

Drilling and Oil Field Services Operations

We provide drilling and related oil field services to our exploration and production business and to third-parties in both West Texas and the Piceance Basin.

Drilling Operations

We drill for our own account in the WTO through our drilling and oil field services subsidiary, Lariat Services, Inc. In addition, we also drill wells for other natural gas and oil companies, primarily located in the West Texas region. We believe that drilling with our own rigs allows us to control costs and maintain operating flexibility. We are a party to a joint venture, Larclay, with CWEI, where we currently have eleven rigs working for our own account and CWEI. Larclay has one rig that has currently not been assembled. We believe that we are one of the largest privately held drilling contractors in the United States on a footage drilled basis. We believe that our ownership of drilling rigs and our related oil field services will continue to be a catalyst of our growth. Currently, 29 of our rigs are working on properties operated by us, and we are operating 38 rigs, including eleven of the twelve rigs owned by Larclay. Our rig fleet is designed to drill in our specific areas of operation and have an average horsepower of over 800 and an average depth capacity of greater than 10,500 feet.

In 2005, we ordered 22 rigs from Chinese manufacturers for an aggregate purchase price of $126.4 million, which include the cost of assembling and equipping the rigs in the U.S. Due in part to the shortage of experienced drilling employees and various operational challenges, we have deemed it prudent to retrofit five Chinese rigs to a conventional operation. This involves the replacement of the Chinese trailer mounted unit with the traditional box-on-box substructure, cantilever mast and hand-brake drawworks. We anticipate the retrofit will be completed in the second quarter 2008.

The table below identifies certain information concerning our contract drilling operations:

	Year Ended December 31,			Nine Months Ended September 30,	
	2004	**2005**	**2006**	**2006**	**2007**
Number of operational rigs owned at end of period	10	19	25	23	27(3)
Average number of operational rigs owned during the period	8	14.3	21.9	21.0	26(3)
Average number of rigs utilized	8	14.3	21.9	21.0	23.7
Utilization rate	100%	100%	100%	100%	91%
Average drilling revenue per day(1)(2)	$ 73,023	$ 164,495	$ 373,051	$ 358,867	$ 409,541
Average drilling revenue per rig per day(2)	$ 9,128	$ 11,503	$ 17,034	$ 17,089	$ 17,302
Total footage drilled (feet in thousands)	635,684	1,749,700	2,124,079	1,746,763	1,440,247
Number of wells drilled	159	249	379	295	204

(1)

Represents the total revenues from our contract drilling operations divided by the total number of days our drilling rigs were used during the period.

(2) Does not include revenues for related rental equipment.

(3) Does not include five rigs being retrofitted as of June 30, 2007.

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The table below identifies certain information concerning our drilling rigs as of September 30, 2007:

	Owned	Operational	Operating for SandRidge	Operating for Third Parties
Lariat	32(1)	27	21	3
Larclay	12(2)	11	7	4
Total	44	38	28	7

(1) Includes five rigs that were being retrofitted.

(2) Includes one rig that has not been assembled.

Oil Field Services

Our oil field services business began in 1986 and conducts operations that complement our drilling services operation. These services include providing pulling units, coiled-tubing units, trucking, location and road construction roustabout services, mud logging and rental tools to ourselves and to third-parties. Less than 13% of our oil field services revenues are from third-parties. We also provide underbalanced drilling systems for our own wells. Our expected capital expenditures for 2008 related to our oil field services are $50 million.

Types of Drilling Contracts

We obtain our contracts for drilling natural gas and oil wells either through competitive bidding or through direct negotiations with customers. Our drilling contracts generally provide for compensation on a daywork, footage or turnkey basis. The contract terms we offer generally depend on the complexity and risk of operations, the on-site drilling conditions, the type of equipment used, the anticipated duration of the work to be performed and prevailing market rates. For a discussion of these contracts, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Segment Overview Drilling and Oil Field Services.

Our Customers

We perform approximately two-thirds of our drilling services in support of our exploration and production business. We also have significant customer relationships with other operators in West Texas, including Mariner Energy, Inc. For the nine months ended September 30, 2007, we generated revenues of $28.9 million, for drilling services performed for third-parties, with Mariner Energy, Inc. accounting for $18.1 million of those revenues.

In addition, we began receiving delivery of rigs to our Larclay joint venture in the first quarter of 2006. Larclay began drilling wells in the first quarter of 2006. CWEI will utilize fewer Larclay rigs on its own projects than initially anticipated.

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Midstream Gas Services

We provide gathering, compression, processing and treating services of natural gas in the TransPecos region of West Texas and the Piceance Basin. Our midstream operations and assets not only serve our exploration and production business, but also service other natural gas and oil companies. The following tables set forth our primary midstream assets as of September 30, 2007:

ROC Gas Operated Plants	Plant Capacity (Mmcf/d)	Average Utilization(1)	Third Party Usage
Pike s Peak(2)	58	92.2%	less than 1.0%
Grey Ranch(3)	82	89.0%	33.4%
Sagebrush(4)	50	21.9%	17.8%

(1) Average utilization for nine months ended September 30, 2007.

(2) A project to expand Pike s Peak capacity to 70 Mmcf per day was completed in the fourth quarter of 2007.

(3) The Grey Ranch plant is operated by Southern Union. A project to expand the plant to 92 Mmcf/d was completed during the fourth quarter of 2007. We expect the plant capacity will be further increased to 170 Mmcf/d by the third quarter of 2008.

(4) Sagebrush commenced processing operations on May 1, 2007.

PetroSource Facilities	CO_2 Compression Capacity (Mmcf/d)	Average Utilization(1)
Pike s Peak	38	50.0%
Mitchell	26	3.9%
Grey Ranch	40	67.5%
Terrell	38	70.3%

(1) Average utilization for nine months ended September 30, 2007.

West Texas

In Pecos County, we operate and own 100% of the Pike s Peak gas treating plant, which has the capacity to treat 70 Mmcf per day of gas for the removal of CO_2 from natural gas produced in the Piñon Field and nearby areas. We also have a 50% interest in the partnership that leases and operates the Grey Ranch CO_2 treatment plant located in Pecos County, which has the capacity to treat 92 Mmcf per day of gas. We purchased this plant in the fourth quarter of 2007. Further expansion to 170 Mmcf per day is planned for completion by the third quarter of 2008. The treating capacities for both the Pike s Peak and Grey Ranch plants are dependent upon the quality of natural gas being treated. The above numbers for the Pike s Peak and Grey Ranch plants are based on a natural gas stream that is about 65% CO_2.

We also operate or own approximately 367 miles of natural gas gathering pipelines and numerous dehydration units. Within the Piñon Field, we operate separate gathering systems for sweet natural gas and produced natural gas containing high percentages of CO_2. In addition to servicing our exploration and production business, these assets also service other natural gas and oil companies.

A portion of our West Texas assets, including the Pike s Peak plant and approximately 44 miles of pipeline, was acquired from TXU Lone Star in 1999. We have since constructed or acquired approximately 250 miles of pipeline. In 2003, we entered into a 50% joint venture with Southern Union Gas Services, whose primary assets are a lease on the Grey Ranch natural gas treatment plant and a 22-mile pipeline gathering system. The term of the lease expires in mid-2010, however we purchased the Grey Ranch plant during the fourth quarter of 2007. Our two West Texas plants remove CO_2 from natural gas production and deliver residue gas into the Atmos Lone Star and Enterprise Energy Services pipelines. These assets are operated on fixed fees based upon throughput of natural gas. We have also secured 50 Mmcf/d of treating capacity at Anadarko s Mitchell Plant under a long term favorable fixed fee arrangement.

The vast majority of the produced natural gas gathered by our midstream assets in West Texas requires compression. ROC Gas currently owns and operates approximately 45,000 horsepower of gas compression.

Other Areas

Our Piceance Basin system consists of 50 Mmcf per day of processing plants and approximately 53 miles of pipeline gathering systems and approximately 4,400 horsepower. We gather and transport our natural gas and third-party natural gas to market delivery points on Colorado Interstate Gas Company, Questar and Rocky Mountain Natural Gas Pipelines.

We also own approximately 70 miles of pipeline gathering systems and operate more than 10,000 horsepower in East Texas and approximately 44 miles of pipeline gathering systems in the Gulf Coast area.

Capital Expenditures

The growth of our midstream assets is driven by our exploration and development operations. Historically, pipeline and facility expansions are made when warranted by the increase in production or the development of additional acreage. As a result of our increased production from the Piñon Field during 2007, we have experienced some compressor capacity limitations and relatively poor runtime during the first half of 2007. The current system does not have surplus horsepower to compensate for periods of scheduled maintenance. When units are serviced or go down unexpectedly, we lose throughput and experience higher line pressures, which impact the deliverability. Additionally, some of our compressor units in the Piñon Field have been operating at high loads, which may result in excessive wear and downtime. In order to ensure sufficient capacity for our existing and future Piñon Field production, we plan to install additional compression in the field.

Additionally, with our anticipated increase of high CO_2 gas production in the WTO over the next several years, we intend to build supplemental treating capacity, pipeline gathering infrastructure and compression facilities to accommodate our aggressive growth plans.

Marketing

Through Integra Energy, our subsidiary, we buy and sell the natural gas and oil production from SandRidge-operated wells and third-party operated wells within our West Texas operations. Through Integra Energy, we will purchase and sell residue gas from the Sagebrush plant into Questar and Colorado Interstate Gas pipelines. We generally buy and sell natural gas on back-to-back contracts using a portfolio of baseload and spot sales agreements. Identical volumes are bought and sold on monthly and daily contracts using a combination of Inside F.E.R.C. and Gas Daily pricing indices to eliminate price exposure. We market our oil and condensate production in both Texas and Colorado to Shell Trading U.S. Company at current market rates.

We do not actively seek to buy and sell third-party natural gas due to onerous credit requirements and minimal margin expectations. We conduct thorough credit checks with all potential purchasers and minimize our exposure by contracting with multiple parties each month. We do not engage in any hedging activities with respect to these contracts. We manage several interruptible natural gas transportation agreements in order to take advantage of price differentials or to secure available markets when necessary. At present, we do not have any firm transportation agreements, but we are in the process of securing firm transportation for a portion of our Piñon Field production.

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Other Operations

Our CO_2 gathering, merchant sales and tertiary oil recovery operations are conducted through our wholly-owned subsidiary, PetroSource. PetroSource owns 231 miles of CO_2 pipelines in West Texas with approximately 92,000 horsepower of owned and leased CO_2 compression available with approximately 54,000 horsepower currently operational. In addition, PetroSource has exclusive long-term supply contracts to gather CO_2 from natural gas treatment plants in West Texas and is the sole gatherer of CO_2 from the four natural gas treatment plants located in the Delaware and Val Verde Basins of West Texas. The primary use of our CO_2 supply is for use in our and third-parties tertiary oil recovery operations. We have assembled an experienced CO_2 management team, including engineers and geologists with extensive experience in CO_2 flooding with industry leaders.

Production from most oil reservoirs includes three distinct phases: primary, secondary, and tertiary, or enhanced recovery. During primary recovery, the natural pressure of the reservoir or gravity drives oil into the wellbore and artificial lift techniques (such as pumps) produce the oil to the surface. However, only about 10% to 15% of a reservoir s original oil in place is typically produced during primary recovery. Secondary recovery techniques, most commonly waterflooding, often increase ultimate recovery to more than 20% to 45% of the original oil in place. This technique involves injecting water to displace oil and drive it to the wellbore. Even after a water flood, the majority of the original oil in place is still un-recovered. Tertiary, or enhanced recovery techniques, such as CO_2 flooding, can recover additional oil. In CO_2 flooding, the CO_2 is injected into the reservoir. At high pressures (approximately 2,000 psi), the CO_2 is in a liquid phase and can become miscible with the oil, which means the CO_2 and oil mix together and form one fluid. This mixing changes the fluid properties of the oil and enables this trapped oil to begin to move in the reservoir again. The result is a potentially significant increase in production. CO_2 injection can recover, on average, an additional 10% to 16% of the original oil in place in a field over a period of 20 to 30 years. Mature fields that have been abandoned may still be viable candidates for CO_2 floods. CO_2 flooding typically extends the life of oil fields by 20 years.

In 2004 and 2005, we acquired West Texas waterfloods, the Wellman and South Mallet Units and the George Allen Unit for the purpose of evaluating for potential implementation of tertiary oil recovery operations utilizing our equity CO_2 supply. For a discussion of our tertiary reserves and production at the units, please read Exploration and Production Operations Tertiary Oil Recovery. We have also identified numerous other properties that are attractive candidates for implementing CO_2 projects. We believe we have a competitive advantage in identifying, acquiring and developing these properties because of our expertise and large available CO_2 supply.

PetroSource currently has approximately 95 Mmcf per day of CO_2 in available supply. We currently deliver the majority of this supply to Occidental Permian Ltd. and Chevron Corporation. In September 2007, we captured and sold 79.5 Mmcf per day. Our long term contracts in place with Occidental provide for the exchange of up to 60% of the delivered volumes. We believe our current tertiary oil recovery properties will require approximately 60 Mmcf of CO_2 per day over the next five years. We intend to increase our supply of CO_2 in order to provide sufficient capacity as our tertiary oil recovery operations grow through additional acquisitions and expansions. We expect the supply of CO_2 to increase as additional natural gas reserves with a high CO_2 content are developed in the Piñon and surrounding fields. In addition, we intend to increase the capacity of our CO_2 treating, gathering and transportation assets which will continue to provide for our equity CO_2 needs, as well as the expansion of our merchant sales business. We recently completed the refurbishment of an additional compressor unit at the Grey Ranch plant at a cost of approximately $1.2 million. The unit added 6,350 operational horsepower and 16 Mmcf per day of capacity to our system.

In addition to gathering CO_2 for use in tertiary oil recovery operations, our CO_2 assets may create another economic benefit by generating Emissions Reduction Credits (ERCs). Approximately one-third of the states of the U.S. have passed laws, adopted regulations or undertaken regulatory initiatives to track and/or reduce the emission of greenhouse gases, such as CO_2 and methane. In addition, the U.S. Congress is actively considering legislation to reduce emissions of greenhouse gases, and in light of the U.S. Supreme Court s recent decision in *Massachusetts, et al. v. EPA*, the U.S. Environmental Protection Agency may be required to regulate greenhouse gas emissions from mobile sources (*e.g.*, cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. Certain nations other than the United States have already agreed to regulate emissions of greenhouse gases pursuant to the United Nations Framework Convention on Climate Change, also known as the Kyoto Protocol. We believe that we are well positioned to benefit from the developing market for trading ERCs. We currently capture approximately 1.5 million tons of CO_2 per year. Since that CO_2 would otherwise escape into the atmosphere, the resulting capture of CO_2 generates ERCs that can be sold to parties either needing or desiring to offset their own CO_2 emissions. In the past, we have sold a portion of our ERCs; however, this market is still in its infancy and has not been a material source of income. In the coming years, we expect ERCs to become a greater source of income.

Competition

We believe that our leasehold acreage position, oil field service businesses, midstream assets, CO_2 supply and technical and operational capabilities generally enable us to compete effectively. However, the natural gas and oil industry is intensely competitive, and we face competition in each of our business segments.

We believe our geographic concentration of operations and vertical integration enable us to compete effectively with our exploration and production operations. However, we compete with companies that have greater financial and personnel resources than we do. These companies may be able to pay more for producing properties and undeveloped acreage. In addition, these companies may have a greater ability to continue exploration activities during periods of low natural gas and oil market prices. Our larger or integrated competitors may be able to absorb the burden of any existing and future federal, state, and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing natural gas and oil properties.

We believe the type, age and condition of our drilling rigs, the quality of our crew and the responsiveness of our management generally enable us to compete effectively. However, to the extent we drill for third-parties, we encounter substantial competition from other drilling contractors. Our primary market area is highly competitive. The drilling contracts we compete for are sometimes awarded on the basis of competitive bids. We believe pricing and rig availability are the primary factors our potential customers consider in determining which drilling contractor to select. While we must be competitive in our pricing, our competitive strategy generally emphasizes the quality of our equipment, the experience of our rig crews and our willingness to drill on a turnkey basis, to differentiate us from our competitors. This strategy is less effective when demand for drilling services is weak or there is an oversupply of rigs, as these conditions usually result in increased price competition, which makes it more difficult for us to compete on the basis of factors other than price. Many of our competitors have greater financial, technical and other resources than we do. Their greater capabilities in these areas may enable them to better withstand industry downturns and better retain skilled rig personnel.

We believe our geographic concentration of operations enables us to compete effectively in our midstream business segment. Most of our midstream assets are integrated with our production. However, with respect to third-party gas and acquisitions, we compete with companies that have greater financial and personnel resources than we do. These companies may be able to pay more for acquisitions. In addition, these companies may have a greater ability to price their services below our prices for similar services. Our larger or integrated competitors may be able to absorb the burden of any existing and future federal, state, and local laws and regulations more easily than we can, which would adversely affect our competitive position.

We believe our supply of CO_2, focus on small to mid-sized acquisitions and technical expertise enable us to compete effectively in our PetroSource business. However, we face the same competitive pressures in this business that we do in our traditional exploration and production segment.

Seasonal Nature of Business

Generally, the demand for natural gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or cool summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. Seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other natural gas and oil operations in a portion of our operating areas. These seasonal anomalies can pose challenges for meeting our well drilling objectives and can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations.

Environmental Matters and Regulation

General

We are subject to various stringent and complex federal, state and local laws and regulations governing environmental protection 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;
- require the installation of expensive pollution control equipment;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with natural gas and oil drilling production, transportation and processing activities;
- suspend, limit, prohibit or require approval before construction, drilling and other activities in certain lands lying within wilderness, wetlands and other protected areas; and
- require remedial measures to mitigate pollution from historical and ongoing operations, such as the closure of pits and plugging of abandoned wells.

These laws, rules and regulations may also restrict the rate of natural gas and oil production below the rate that would otherwise be possible. The regulatory burden on the natural gas and oil industry increases the cost of doing business in the industry and consequently affects profitability.

Governmental authorities have the power to enforce compliance with environmental laws, regulations and permits, and violations are subject to injunction, as well as administrative, civil and even criminal penalties. The effects of these laws and regulations, as well as other laws or regulations that may be adopted in the future, could have a material adverse impact on our business, financial condition and results of operations.

Below is a discussion of the environmental laws and regulations that could have a material impact on the oil and gas industry.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, also known as the Superfund law, and analogous state laws impose joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to strict, joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for 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. In the course of our operations, we generate wastes that may fall within CERCLA s definition of hazardous substances. Further, natural gas and oil exploration, production, processing and other activities have been conducted at some of our properties by previous owners and

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operators, and materials from these operations remain on some of our properties and in some cases may require remediation. Therefore, governmental agencies or third-parties could seek to hold us responsible under CERCLA or similar state laws for all or part of the costs to clean up a site at which hazardous substances may have been released or deposited.

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 U.S. 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 excluded from regulation as RCRA hazardous wastes but instead are regulated under RCRA s non-hazardous waste provisions. However, it is possible that certain natural gas and oil exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change would likely increase our operating expenses, which could have a material adverse effect on our business, financial condition or results of operations as well as the industry, in general.

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, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. These regulatory programs may require us to obtain permits before commencing construction on a new source of air emissions, and may require us to reduce emissions at existing facilities. As a result, we may be required to incur increased capital and operating costs. For instance, the Grey Ranch natural gas treatment plant currently operates under a grandfather clause, which expires, possibly in as early as September 2008. Southern Union, the operator of the Grey Ranch plant, has been in discussions with the Texas Commission on Environmental Quality concerning an extension of the grandfather clause protection until January 2011. We expect that the State of Texas will require us to obtain an air emissions permit for the plant prior to the expiration of the grandfather clause. The new air permit may impose new, lower air emissions limits for nitrogen oxides and possibly other contaminants, and we may be required to incur capital costs to upgrade the plant s air emissions control equipment in order to achieve these new, lower air emissions limits. Based on information currently available to us, we estimate that the cost to upgrade the plant if new, lower air emissions limits are imposed by the new air permit could be approximately $7 million, of which we would be responsible for approximately $3.5 million and Southern Union would be responsible for approximately $3.5 million. Additionally, 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.

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 spills and leaks of oil and other substances into waters of the United States, including wetlands as well as state waters. These laws prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and other substances related to the oil and natural gas industry into onshore, coastal and offshore waters without appropriate permits. Some of the pollutant limitations have become more restrictive over the years and additional restrictions and limitations may be imposed in the future. The Clean Water Act also regulates storm water discharges from industrial and construction activities. Regulations promulgated by the EPA and state regulatory agencies require industries engaged in certain industrial or construction activities to acquire permits and implement storm water management plans and best management practices, to conduct periodic monitoring and reporting of discharges, and to train employees. Further, federal and state regulations require certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. There are costs associated with each of these regulatory requirements. In addition, 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 Oil Pollution Act of 1990, or OPA, which amends and augments the Clean Water Act, establishes strict liability for owners and operators of facilities that are the site of a release of oil into waters of the United States. In addition, OPA and regulations promulgated pursuant thereto impose a variety of regulations on responsible parties related to the prevention of oil spills and liability for cleanup and natural resource damages resulting from such spills. For example, certain natural gas and oil operators must develop, implement and maintain facility response plans, conduct annual spill training for certain employees and provide varying degrees of financial assurance.

National Environmental Policy Act

Natural gas and oil 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 having 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, limit or even prohibit our development of natural gas and oil projects in covered areas.

Global Warming and Climate Control

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to warming of the Earth s atmosphere. In response to such studies, the U.S. Congress is actively considering legislation to reduce emissions of greenhouse gases and at least 17 states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Also, as a result of the U.S. Supreme Court s decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA may be required to regulate greenhouse gas emissions from mobile sources (*e.g.*, cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Court s holding in *Massachusetts, et al. v. EPA,* that greenhouse gases fall under the federal Clean Air Act s definition of air pollutant may also result in future regulation of greenhouse gas emissions from stationary sources under certain Clean Air Act programs. Certain nations have already agreed to regulate emissions of greenhouse gases pursuant to the Kyoto Protocol, an international treaty pursuant to which participating countries (not including the United States) have agreed to reduce their emissions of greenhouse gases to below 1990 levels by 2012. Passage of climate control legislation or other regulatory initiatives by Congress or various states of the U.S., or the adoption of regulations by the EPA and analogous state agencies that restrict emissions of greenhouse gases in areas in which we conduct business could have an adverse affect on some of our operations and demand for some of our services or products.

Anti-Terrorism Measures

The federal Department of Homeland Security Appropriations Act of 2007 requires the Department of Homeland Security or DHS, to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that are deemed to present high levels of security risk. The DHS issued an interim final rule in April 2007 regarding risk-based performance standards to be attained pursuant to the act and, on November 20, 2007, further issued an Appendix A to the interim rules that establish chemicals of interest and their respective threshold quantities that will trigger compliance with these interim rules. We have not yet determined the extent to which our facilities are subject to the interim rules or the associated costs to comply, but it is possible that such costs could be substantial.

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Other Regulation of the Natural Gas and Oil Industry

The natural gas and oil industry is extensively regulated by numerous federal, state and local authorities, including Native American tribes. Legislation affecting the natural gas and oil industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, and Native American tribes are authorized by statute to issue rules and regulations binding on the natural gas and oil industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the natural gas and oil industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Drilling and Production

Our operations are subject to various types of regulation at federal, state, local and Native American tribal levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties, municipalities and Native American tribes, in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the rates of production or allowables;
- the surface use and restoration of properties upon which wells are drilled and other third-parties;
- the plugging and abandoning of wells; and
- notice to surface owners and other third-parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of natural gas and oil properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third-parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from natural gas and oil wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of natural gas and oil we can produce from our wells or limit the number of wells or the locations at which we can drill. 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.

Federal, state and local regulations provide detailed requirements for the abandonment of wells, closure or decommissioning of production facilities and pipelines, and for site restoration, in areas where we operate. MMS regulations require that owners and operators plug and abandon wells and decommission and remove offshore facilities located in federal offshore lease areas in a prescribed manner. The MMS requires federal leaseholders to post performance bonds or otherwise provide necessary financial assurances to provide for such abandonment, decommissioning and removal. The Railroad Commission of Texas has financial responsibility requirements for owners and operators of facilities in state waters to provide for similar assurances. The U.S. Army Corps of Engineers, or ACOE, and many other state and local municipalities have regulations for plugging and abandonment, decommissioning and site restoration. Although the ACOE does not require bonds or other financial assurances, some other state agencies and municipalities do have such requirements.

Natural Gas Sales Transportation

Historically, federal legislation and regulatory controls have affected the price of the natural gas we produce and the manner in which we market our production. The Federal Energy Regulatory Commission, or FERC, has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Since

1978, various federal laws have been enacted which have resulted in the complete removal of all price and non-price controls for sales of domestic natural gas sold in first sales, which include all of our sales of our own production.

FERC also 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. Commencing in 1985, FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC s initiatives have led to the development of a competitive, unregulated, open access market for gas purchases and sales that permits all purchasers of gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the less stringent regulatory approach recently pursued by FERC and Congress will continue indefinitely into the future nor can we determine what affect, if any, future regulatory changes might have on our natural gas related activities.

Under FERC s current regulatory regime, transmission services must be provided on an open-access, non-discriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and instate waters. Although its policy is still in flux, FERC recently 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.

Employees

As of September 30, 2007, we had approximately 2,200 full-time employees and eight part-time employees, including more than 100 geologists, geophysicists, petroleum engineers, technicians, land and regulatory professionals. Of our approximately 2,220 employees, 292 are located at our headquarters in Oklahoma City, nine in Amarillo, Texas and the remaining 1,907 employees are working in our various field offices and drilling sites.

Offices

We currently lease 67,347 square feet of office space in Oklahoma City, Oklahoma at 1601 N.W. Expressway, where our principal offices are located, and another 28,059 square feet in Enterprise Plaza, which is nearby. The term of the leases expires for our space at 1601 N.W. Expressway on August 31, 2009. For our space at Enterprise Plaza, the term of lease expires on October 31, 2009 for 18,547 square feet, and April 31, 2008 for 9,433 square feet. We also lease or sublease 37,873 square feet of office space in Amarillo, Texas at 701 S. Taylor Street, where our principal offices were previously located. The leases for our Amarillo office expire in April 2009. We also lease 6,725 square feet of office space at 16801 Greenspoint Park Drive in Houston, Texas. This lease expires in January 2014. PetroSource currently leases approximately 3,529 square feet in Midland, Texas. The PetroSource lease expires in December 2008. We also own an approximate 10,000 square foot office building in Midland, Texas. We also own 4,358 square feet of office space and 6,240 square feet of shop space in Odessa, Texas, which serves as the headquarters of Lariat Services. In addition, we have a field office located in Terry County, Texas and Rifle, Colorado. We believe that our office facilities are adequate for our short-term needs.

On July 12, 2007, we purchased several buildings in downtown Oklahoma City, Oklahoma, including the Kerr-McGee Tower, from Chesapeake for approximately $25 million. These properties are located at 123 Robert S. Kerr Avenue and contain approximately 450,000 square feet of office space. We intend to relocate our principal offices from 1601 N.W. Expressway to the Kerr-McGee Tower.

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Legal Proceedings

On May 18, 2004, we commenced a civil action seeking declaratory judgment against Elliot Roosevelt, Jr., E.R. Family Limited Partnership and Ceres Resource Partners, L.P. in the District Court of Dallas County, Texas, 101st Judicial District, SandRidge Energy, Inc. and Riata Energy Piceance, LLC v. Elliot Roosevelt, Jr. et al, Cause No. 92.717-C. This suit sought a declaratory judgment relating to the rights of the parties in and to certain leases in a defined area of mutual interest in the Piceance Basin pursuant to an acquisition agreement entered into in 1989, including our 41,454 gross (16,193 net) acreage position. We tried the case to a jury in July 2006. Before the case was submitted to the jury, the trial court granted Roosevelt a directed verdict stating that he owned a 25% deferred interest in our acreage after project payout. The directed verdict is not likely to affect our proved reserves of 11.7 Bcfe, because of the requirement that project payout be achieved before the deferred interest shares in revenue. Other issues of fact were submitted to the jury. The trial court recently entered a judgment favorable to Roosevelt. We have filed a motion to modify the judgment and for a new trial. Depending on the outcome of this motion, we expect to appeal, at a minimum, from the entry of the directed verdict. If we do not ultimately prevail, the deferred interest will reduce our economic returns from the project, if project payout is achieved.

We are subject to other claims in the ordinary course of business. However, we believe that the ultimate resolution of the above mentioned claims and other current legal proceedings will not have a material adverse effect on our financial condition or results of operations.

MANAGEMENT

The following table sets forth information regarding our executive officers, our directors and other key employees as of January 14, 2008.

Name	Age	Position
Tom L. Ward	48	Chairman, Chief Executive Officer and President
Dirk M. Van Doren	48	Executive Vice President and Chief Financial Officer
Matthew K. Grubb	44	Executive Vice President and Chief Operating Officer
Larry K. Coshow	49	Executive Vice President Land
Todd N. Tipton	52	Executive Vice President Exploration
Rodney E. Johnson	50	Senior Vice President Reservoir Engineering
V. Bruce Thompson	60	Senior Vice President Legal and General Counsel
Thomas L. Winton	61	Senior Vice President Information Technology and Chief Information Officer
Mary L. Whitson	46	Senior Vice President Human Resources
Randall D. Cooley	53	Senior Vice President Accounting
Kevin R. White	50	Senior Vice President Business Development
Bill Gilliland	70	Director
Dan Jordan	50	Director
Roy T. Oliver, Jr.	55	Director
Stuart W. Ray	63	Director
D. Dwight Scott	44	Director
Jeffrey Serota	41	Director

Tom L. Ward (Chairman, Chief Executive Officer and President) Mr. Ward has served as our Chairman and Chief Executive Officer since June 2006 and as our President since December 2006. Prior to joining SandRidge, he served as President, Chief Operating Officer and a director of Chesapeake Energy Corporation (NYSE: CHK) from the time he co-founded the company in 1989 until February 2006. From February 2006 until June 2006, Mr. Ward managed his private investments. Chesapeake Energy Corporation is the second largest independent natural gas producer in the U.S. Mr. Ward graduated from the University of Oklahoma in 1981 with a Bachelor of Business Administration in Petroleum Land Management. He is a member of the Board of Trustees of Anderson University in Anderson, Indiana.

Dirk M. Van Doren (Executive Vice President and Chief Financial Officer) Mr. Van Doren has served as our Chief Financial Officer since June 2006. He served in High Yield Research at Goldman Sachs from 1999 until May 2006 and prior to that he was in Equity Research at Bear Stearns. Mr. Van Doren graduated from Colgate University in 1981 with a Bachelor of Arts in Political Science and International Relations and earned a Masters degree in Business Administration from Duke University, The Fuqua School of Business in 1985.

Matthew K. Grubb (Executive Vice President and Chief Operating Officer) Mr. Grubb has served as our Executive Vice President and Chief Operating Officer since June 2007. Prior to this, he had served as our Executive Vice President Operations since August 2006. Mr. Grubb was employed by Samson Resources beginning in 1995 and served as Division Operations Manager of East Texas and Southeast U.S. Regions for Samson Resources from 2002 through July 2006. Prior to that he was in Business Development at Enogex Inc. and held various technical positions at ConocoPhillips. Mr. Grubb holds a Bachelor of Science degree in Petroleum Engineering in 1986 and a Master of

Science degree in Mechanical Engineering in 1988, both from Texas A&M University.

Larry K. Coshow (Executive Vice President Land) Mr. Coshow has served as our Executive Vice President Land since September 2006. He previously worked in various land management capacities for Chesapeake Energy Corporation from 1999 through August 2006. Mr. Coshow also worked in various land management capacities at JMA Energy Company, Samson Resources and Texas Oil & Gas Corp. Mr. Coshow received a Bachelor of Business Administration in Petroleum Land Management from the University of Oklahoma in 1981 and earned his Masters degree in Business Administration from Oklahoma City University s

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Meinders School of Business in 1993. A founding board member for the University of Oklahoma Football Lettermen s Association, Mr. Coshow serves on the board of directors for the University of Oklahoma s Varsity O Club and is also an active member of the Oklahoma state board for the Fellowship of Christian Athletes.

Todd N. Tipton (Executive Vice President Exploration) Mr. Tipton joined us as Executive Vice President of Exploration in September 2006. Prior to this, he was Exploration Manager of the Western Division from 2001 through August 2006 for Devon Energy. His career began with Conoco in geophysical acquisition, processing and interpretation and he continued to hold corporate and management positions of increasing responsibilities until he left in 1994 to join Alberta Energy Company (EnCana). After EnCana, Mr. Tipton worked for Samson Resources and in private consulting. He received a Bachelor degree in Geology from The State University of New York at Buffalo in 1977, and completed an executive development program at The Johnson Graduate School of Management at Cornell University. Mr. Tipton is a member of the Rocky Mountain Association of Geologists and a member of the Independent Petroleum Association of Mountain States.

Rodney E. Johnson (Senior Vice President Reservoir Engineering) Mr. Johnson joined us as Vice President of Reservoir Engineering in January 2007 and was promoted to Senior Vice President Reservoir Engineering in June 2007. He most recently served as Manager of Reservoir Engineering over Texas and Louisiana Regions for Chesapeake Energy Corporation from October 2003 through December 2006. Prior to this, Mr. Johnson served as Manager of Technology for Aera Energy (a joint venture of Exxon/Shell) where he held positions of increasing importance from 1996 through September 2003. Mr. Johnson graduated from Wichita State University in 1980 with a Bachelor of Science degree in Mechanical Engineering; he has also been a registered Professional Engineer since 1988.

V. Bruce Thompson (Senior Vice President Legal and General Counsel) Mr. Thompson has served as our General Counsel, Senior Vice President Legal and Secretary since March 2007. From 2003 until joining us, he was Senior Counsel with the law firm of Brownstein Hyatt Farber Schreck, working in the firm s Washington, D.C. and Denver offices. From July 2002 until joining Brownstein Hyatt Farber Schreck, Mr. Thompson was a self employed lobbyist and consultant for oil and gas related companies, both domestically and internationally. Mr. Thompson has also served as Senior Vice President and General Counsel of Forest Oil Corporation and Chief of Staff for then Congressman, now U.S. Senator, James Inhofe. Mr. Thompson graduated from the University of Pennsylvania Wharton School of Business with a Bachelor of Science degree in Economics in 1969 and received his Juris Doctorate from the University of Tulsa College of Law in 1974.

Thomas L. Winton (Senior Vice President Information Technology & CIO) Mr. Winton has served as our Senior Vice President Information Technology and Chief Information Officer since May 2006. Prior to joining us, Mr. Winton served as Senior Vice President and Chief Information Officer for Chesapeake Energy Corporation from July 1998 until retiring in July 2005. Mr. Winton obtained a Bachelor of Science degree in Mathematics from Oklahoma Christian University in 1969, a Masters degree in Mathematics from Creighton University in 1973, and Masters degree in Business Administration from the University of Houston in 1980. Mr. Winton also completed the Tuck Executive Program, Tuck School of Business, Dartmouth College in 1987.

Mary L. Whitson (Senior Vice President Human Resources) Ms. Whitson has served as our Senior Vice President Human Resources since September 2006. Ms. Whitson was the Vice President Human Resources for Chesapeake Energy Corporation through August 2006, where she held human resources management positions of increasing responsibility for more than eight years. Prior to 1998, she was the Human Resources Manager for FKW, Incorporated, an architecture and government services contracting firm, where she was employed for 16 years. She attended Oklahoma State University and received a Bachelor of Science degree from the University of Central Oklahoma in 1996. Certified as a Senior Professional in Human Resources (SPHR), Ms. Whitson is a graduate of Leadership Oklahoma City Class XXIV and currently serves as a member of the board of directors for the YWCA of

Oklahoma City.

Randall D. Cooley (Senior Vice President Accounting) Mr. Cooley joined us as Vice President Accounting in November 2006, upon acquisition of NEG Oil & Gas LLC. and was promoted to Senior Vice

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President - Accounting in January 2008. Prior to joining SandRidge, Mr. Cooley served as the senior financial officer with National Energy Group, Inc., having held the position of Vice President and Chief Financial Officer since March 2003. From 1989 until 2001, Mr. Cooley was Vice President, Controller and Chief Financial Officer for Shana Petroleum Company. From 1984 until 1989, he was controller for Rebel Drilling Company and Wildcat Well Service and prior to this was employed in public accounting. Mr. Cooley earned a Bachelor of Science in Business Administration, with a major in Accounting, from the University of Southern Mississippi in 1978 and is a Certified Public Accountant.

Kevin R. White (Senior Vice President Business Development) Mr. White joined us as Senior Vice President Business Development in January 2008. Prior to joining SandRidge, he worked for six years as a consultant in the oil and gas industry. Mr. White served as Executive Vice President of Corporate Development and Strategic Planning for Louis Dreyfus Natural Gas from 1993 until the company was sold in 2001. He attended Oklahoma State University, receiving his Bachelor of Science degree in Accounting in 1979, a Masters of Science degree in Accounting and his Certified Public Accountant qualification in 1980.

Bill Gilliland (Director) Mr. Gilliland was appointed as a director on January 7, 2006. Mr. Gilliland has served as managing partner of several personal and family investment partnerships, including Gillco Energy, L.P. and Gillco Investments, L.P., since April 1999. Prior to this, Mr. Gilliland was the founder, Chief Executive Officer, President and Chairman of Cross-Continent Auto Retailers, Inc. Mr. Gilliland holds a Bachelor of Business Administration from North Texas State University.

Dan Jordan (Director) Mr. Jordan was appointed as a director of SandRidge in December 2005. Mr. Jordan also has served as a director of PetroSource since May 2004 and served as a Vice President and director of Symbol Underbalanced Air Services and Larco from August 2003 to September 2005. From October 2005 through August 2006, Mr. Jordan served as our Vice President, Business. Since September 2006, Mr. Jordan has been involved in private investments. Prior to joining SandRidge, Mr. Jordan founded Jordan Drilling Fluids, Inc. and served as its Chairman, President and Chief Executive Officer from March 1984 to July 2005. Mr. Jordan sold Jordan Drilling Fluids, Inc. and its wholly owned subsidiary, Anchor Drilling Fluids USA Inc., in August 2005. At that time, Anchor Drilling Fluids USA Inc. was the largest privately held domestic drilling fluids firm.

Roy T. Oliver, Jr. (Director) Mr. Oliver was appointed as a director on July 13, 2006. Mr. Oliver has served as President of R.T. Oliver Investments, Inc., a diversified investment company with interests in energy, energy services, media and real estate, since August, 2001. The company presently owns the largest portfolio of class A office properties in Oklahoma. He has served as President and Chairman of the Board of Valliance Bank, N.A. since August 2004. He founded U.S. Rig and Equipment, Inc. in 1980 and served as its President until its assets were sold in August 2003. Mr. Oliver is a graduate of The University of Oklahoma with a Bachelor of Business Administration degree. He serves on The University of Oklahoma Michael F. Price College of Business Board of Advisors.

Stuart W. Ray (Director) Mr. Ray was appointed as a director on December 14, 2007. Mr. Ray is a Partner of Sonenshine Partners LLC, a New York City based investment banking firm, and a Partner of Urban American Partners, LLC, a New Jersey based real estate investment and management firm that owns and operates portfolios of workforce housing units. Mr. Ray has also served on the board of directors of GreenHunter Energy, Inc. since December 2007. Mr. Ray is a Chartered Financial Analyst, a member of the New York Society of Security Analysts, and a registered broker with the NASD. He received his Bachelor of Arts from Harvard College and Master in Business Administration from Harvard Business School.

D. Dwight Scott (Director) Mr. Scott was appointed as a director on March 20, 2007. He has been a Managing Director of GSO Capital Partners, an investment advisor specializing in the leveraged finance marketplace since September 2005. Prior to joining GSO, Mr. Scott was Executive Vice President and Chief Financial Officer for

El Paso Corporation from October 2002 until August 2005. He is a member of the Board of Directors of MCV Investors, Inc., United Engines Holding Company LLC, KIPP, Inc. and the Board of Trustees of the Council on Alcohol and Drugs Houston. Mr. Scott earned a Bachelor s degree from the University of North Carolina at Chapel Hill and a Master s of Business Administration from the University of Texas at Austin.

Jeffrey Serota (Director) Mr. Serota was appointed as a director of SandRidge Energy, Inc. on March 20, 2007. He has served as a Senior Partner with Ares Management LLC, an independent Los Angeles based investment firm, since September 1997. Prior to joining Ares, Mr. Serota worked at Bear Stearns from March 1996 to September 1997, where he specialized in providing investment banking services to financial sponsor clients of the firm. He currently serves on the Board of Directors of Marietta Holding Corporation, Douglas Dynamics, LLC, AmeriQual Group LLC, WCA Waste Corporation and White Energy, Inc. Mr. Serota graduated magna cum laude with a Bachelor of Science degree in Economics from the University of Pennsylvania s Wharton School of Business and received a Masters of Business Administration degree from UCLA s Anderson School of Management.

Board of Directors

Our board of directors currently consists of seven directors, Messrs. Ward, Gilliland, Jordan, Oliver, Ray, Scott and Serota. We are subject to all of the provisions of Sarbanes-Oxley Act of 2002 and related SEC rules. In addition, because our common stock is listed on the New York Stock Exchange, a majority of our directors will be required to meet standards of independence by November 5, 2008. We believe that Messrs. Oliver, Ray, Scott and Serota currently meet these independence standards.

Our certificate of incorporation and bylaws provide for a classified board of directors consisting of three classes of directors, each serving staggered three-year terms. As a result, stockholders will elect a portion of our board of directors each year. Class I directors terms will expire at the annual meeting of stockholders to be held in 2010, Class II directors terms will expire at the annual meeting of stockholders to be held in 2008 and Class III directors terms will expire at the annual meeting of stockholders to be held in 2009. The Class I directors are Messrs. Gilliland, Scott and Serota, the Class II directors are Messrs. Ward and Oliver, and the Class III directors are Messrs. Jordan and Ray. At each annual meeting of stockholders held after the initial classification, the successors to directors whose terms will then expire will be elected to serve from the time of election until the third annual meeting following election. The division of our board of directors into three classes with staggered terms may delay or prevent a change of our management or a change in control. See Description of Capital Stock Anti-Takeover Effects of Provisions of Delaware Law, Our Certificate of Incorporation and Bylaws Classified Board; Renewal of Directors.

In addition, our bylaws provide that the authorized number of directors, which shall constitute the whole board of directors, may be changed by resolution duly adopted by the board of directors. Any additional directorships resulting from an increase in the number of directors will be distributed among the three classes so that, as nearly as possible, each class will consist of one-third of the total number of directors. Vacancies and newly created directorships may be filled by the affirmative vote of a majority of our directors then in office, even if less than a quorum.

Committees of the Board

Audit Committee. We established an audit committee during the second quarter of 2007 consisting of Messrs. Scott, Oliver and Serota, each of whom has been determined to be independent under the rules of the SEC and the listing requirements of the New York Stock Exchange by our board of directors. Upon the appointment of Mr. Ray to our board of directors in December 2007, Mr. Oliver resigned from our audit committee, and Mr. Ray was appointed to our audit committee. Mr. Ray has been determined to be independent under the rules of the SEC and the listing requirements of the New York Stock Exchange by our board of directors. Mr. Scott serves as chairman of this committee and has been determined by our board of directors to be an audit committee financial expert as defined under the rules of the SEC. This committee oversees, reviews, acts on and reports on various auditing and accounting matters to our board of directors, including: the selection of our independent accountants, the scope of our annual audits, fees to be paid to the independent accountants, the performance of our independent accountants and our accounting practices. In addition, the audit committee oversees our compliance programs relating to legal and regulatory requirements.

Compensation Committee. We established a compensation committee in the fourth quarter of 2007 consisting of Messrs. Gilliland, Oliver and Scott. Messrs. Oliver and Scott have been determined to be

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independent under the listing requirements of the New York Stock Exchange by our board of directors. We expect that this committee will consist solely of independent directors within one year of listing. Mr. Gilliland serves as chairman of this committee. This committee will establish salaries, incentives and other forms of compensation for officers and other employees. Our compensation committee will also administer our incentive compensation and benefit plans. We have adopted a compensation committee charter defining the committee s primary duties in a manner consistent with the rules of the New York Stock Exchange, which is available on our website.

Nominating and Corporate Governance Committee. We established a nominating and corporate governance committee in the fourth quarter of 2007 consisting of Messrs. Jordan and Serota. In December 2007, Mr. Ray was appointed to our nominating and corporate governance committee. Each of Messrs. Ray and Serota has been determined to be independent under the listing requirements of the New York Stock Exchange by our board of directors. We expect that this committee will consist solely of independent directors within one year of listing. Mr. Jordan serves as chairman of this committee. This committee will identify, evaluate and recommend qualified nominees to serve on our board of directors, develop and oversee our internal corporate governance processes and maintain a management succession plan. We have adopted a nominating and corporate governance committee charter defining the committee s primary duties in a manner consistent with the rules of the New York Stock Exchange, which is available on our website.

Compensation Committee Interlocks and Insider Participation

None of our executive officers serve as a member of the board of directors or compensation committee of any entity that has one or more of its executive officers serving as a member of our board of directors. During the last fiscal year Mr. Ward, our Chairman, Chief Executive Officer and President, participated in the deliberations of our board of directors concerning executive officer compensation.

Director Compensation

Directors who also serve as employees receive no compensation for serving on our board of directors. Non-employee directors receive a $50,000 retainer and $12,500 for each of the four regular meetings of the board of directors attended by such director. In addition, in 2007, each non-employee director received an annual restricted stock grant in the amount of $100,000 based on the fair market value of common stock at the date of grant, which will vest in 25% increments on each of the first four anniversaries following the date of grant.

The following table sets forth the aggregate compensation awarded to, earned by or paid to our directors during 2007.

Name	**Fees Earned or Paid in Cash**	**Stock Awards**	**Total**
Bill Gilliland	$ 100,000(1)	$ 29,215(3)	$ 129,215
Dan Jordan	$ 100,000(2)	$ 30,564(3)	$ 130,564
Roy T. Oliver, Jr.	$ 100,000(4)	$ 29,215(3)	$ 129,215
Stuart W. Ray	$ 12,500(5)	$	$ 12,500
D. Dwight Scott	$ 87,500(6)	$	$ 87,500
Jeffrey Serota	$ 87,500(7)	$	$ 87,500
N. Malone Mitchell, 3rd	$ 75,000(8)	$	$ 75,000

(1)

Consists of (i) $50,000 received as a retainer for one year of service as a non-employee director, and (ii) $50,000 for attending four meetings during 2007.

(2) Consists of (i) $50,000 received as a retainer for one year of service as a non-employee director, and (ii) $50,000 for attending four meetings during 2007.

(3) Includes the dollar amount of compensation expense we recognized for the fiscal year ended December 31, 2007 in accordance with FAS 123R. Pursuant to SEC rules and regulations, the amounts shown exclude the impact of estimated forfeitures related to service-based vesting conditions. These amounts reflect our

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accounting expense for these awards, and do not correspond to the actual value that will be recognized by our directors. Assumptions used in the calculation of these amounts are included in Note 18 to our audited financial statements included in this prospectus. As of December 31, 2007, the number of shares of stock held by each non-employee director was: Mr. Gilliland 1,349,878; Mr. Jordan 1,001,389 and Mr. Oliver 1,001,389.

(4) Consists of (i) $50,000 received as a retainer for one year of service as a non-employee director and (ii) $50,000 for attending four meetings during 2007.

(5) Consists of fees paid for attending one meeting during 2007.

(6) Consists of (i) $37,500 received as a retainer prorated for length of service as a non-employee director and (ii) $50,000 for attending four meetings during 2007.

(7) Consists of (i) $37,500 received as a retainer prorated for length of service as a non-employee director and (ii) $50,000 for attending four meetings during 2007.

(8) Consists of (i) $50,000 received as a retainer for one year of service as a non-employee director and (ii) $25,000 for attending two meetings during 2007.

Indemnification

We have entered into indemnification agreements with all of our directors and executive officers. These indemnification agreements are intended to permit indemnification to the fullest extent now or hereafter permitted by the General Corporation Law of the State of Delaware. 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 us or any of our affiliates, or is or was serving at our request in such a position for another entity. The indemnification agreements also obligate us to promptly advance all reasonable expenses incurred in connection with any claim. The indemnitee is, in turn, obligated to reimburse us 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.

We are not obligated to indemnify the indemnitee with respect to claims brought by the indemnitee against:

- us, except for:
  - claims regarding the indemnitee s rights under the indemnification agreement;
  - claims to enforce a right to indemnification under any statute or law; and counter-claims against us in a proceeding brought by us against the indemnitee; or
- any other person, except for claims approved by our board of directors.

We have also agreed to obtain and maintain director and officer liability insurance for the benefit of each of the above indemnitees. These policies include coverage for losses for wrongful acts and omissions and to ensure our performance under the indemnification agreements. Each of the indemnitees is named as an insured under such policies and provided with the same rights and benefits as are accorded to the most favorably insured of our directors and officers.

Web Access

We provide access through our website at *http://www.sandridgeenergy.com* to current information relating to governance, including a copy of each board committee charter, our Code of Conduct, our corporate governance guidelines and other matters impacting our governance principles. You may also contact our Chief Financial Officer for paper copies of these documents free of charge.

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EXECUTIVE COMPENSATION AND OTHER INFORMATION

Compensation Discussion and Analysis

Introduction

This Compensation Discussion and Analysis (1) provides an overview of our compensation policies and programs; (2) explains our compensation objectives, policies and practices with respect to our executive officers; and (3) identifies the elements of compensation for each of the individuals identified in the following table, whom we refer to in this Compensation Discussion and Analysis as our named executive officers.

Name	Principal Position
Current Officers:	
Tom L. Ward	Chairman, Chief Executive Officer and President
Dirk M. Van Doren	Executive Vice President and Chief Financial Officer
Matthew K. Grubb	Executive Vice President and Chief Operating Officer
Larry K. Coshow	Executive Vice President Land
Todd N. Tipton	Executive Vice President Exploration

Since our inception through June 2006, we were controlled by Mr. N. Malone Mitchell, 3rd our founder and former Chairman, Chief Executive Officer and President. During this time, Mr. Mitchell held ultimate decision making power with respect to the compensation of our executive officers. In June 2006, Mr. Ward purchased a significant portion of Mr. Mitchell s common stock and was appointed as our Chairman and Chief Executive Officer. Mr. Ward s initial compensation level and employment agreement were recommended by a special committee consisting of our independent directors at that time and were approved by our full board of directors. Following Mr. Ward s appointment, we have experienced significant changes in management, including replacement of substantially all of our executive officers, as well as our compensation objectives, policies and practices as described in more detail below. Mr. Mitchell resigned as an officer of the Company on December 31, 2006.

Setting Executive Compensation

Role of our Board and Executive Officers. Prior to June 2006, Mr. Mitchell held ultimate decision making control with respect to the compensation levels of our named executive officers, including himself. In determining compensation levels, Mr. Mitchell relied primarily on his personal experience as Chief Executive Officer and founder of the company. Mr. Mitchell did not participate in the deliberations of the special committee or the board of directors related to the compensation of Mr. Ward.

Since Mr. Ward s appointment in June 2006, executive compensation decisions are generally made on a semi-annual basis by our board of directors or Mr. Ward. Each December, Mr. Ward provides recommendations to our board of directors regarding the compensation levels for our existing executive officers (including himself) and our executive compensation program. After considering these recommendations, our board of directors adjusts base salary levels, determines the amounts of cash bonus awards and determines the amount and vesting of restricted stock grants for each of our executive officers. Each June, Mr. Ward reviews and may adjust the compensation levels of our executive officers, including his own compensation. In making executive compensation decisions and recommendations, Mr. Ward relies primarily on his business judgment, competitive practices and personal experience as co-founder and former President and Chief Operating Officer of Chesapeake. Our compensation committee reviews executive compensation levels on an annual basis based on the recommendations of Mr. Ward and has delegated authority to Mr. Ward to adjust compensation levels semi-annually.

No other named executive officer assumed an active role in the evaluation, design or administration of our 2006 or 2007 executive officer compensation program.

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Role of the Compensation Committee. We established a compensation committee in the fourth quarter of 2007 consisting of Messrs. Gilliland, Oliver and Scott. Messrs. Oliver and Scott have been determined to be independent under the listing requirements of the New York Stock Exchange by our board of directors. We expect that this committee will consist solely of independent directors within one year of listing. The authority of the committee includes, among other things:

- approving, in advance, the compensation and employment arrangements for our executive officers;
- reviewing annually all of the compensation and benefit-based plans and programs in which our executive officers participate;
- administration of our Well Participation Plan; and
- reviewing and recommending all changes to our stock plan to our board of directors, as appropriate, subject to stockholder approval as required.

The charter of our compensation committee grants the committee the sole authority to retain, at our expense, outside consultants or experts to assist it in its duties.

Our board of directors did not engage the services of a compensation consultant to design, review or evaluate our executive compensation arrangements for 2007 or prior thereto.

Objectives of our Executive Compensation Program

Prior to June 2006, our primary executive compensation strategy was to retain our executive officers and reward performance in a manner consistent with similar employers in Amarillo, Texas, the former location of our headquarters. Mr. Mitchell exercised ultimate decision making with respect the compensation of all named executive officers.

Since June 2006, our primary executive officer compensation strategy has been to structure our compensation program to enable us to seek out highly qualified individuals capable of growing the size and enterprise value of our company, complete a successful initial public offering and effectively transition into the new obligations we face as a public company. Due to our significant growth, our move from Amarillo, Texas to Oklahoma City, Oklahoma and our initial public offering, we have hired numerous new employees, including several of the named executive officers. These new hires were accomplished in an environment competitive for highly qualified and experienced energy industry executives which are frequently recruited from larger, established public companies. Accordingly, our compensation philosophy has been to strategically and opportunistically attract executive officers by offering competitive cash compensation packages with the potential for the increased returns associated with a high-growth company.

Our board of directors has established a number of processes to assist it in ensuring that our executive compensation program supports these objectives and our company culture. Among those are competitive benchmarking and assessment of individual and company performance, which are described in more detail below.

Competitive Benchmarking. Our board of directors compares pay practices for our executives against other companies to assist it in the review and comparison of each element of compensation for our executive officers. This practice recognizes that (1) our compensation practices must be competitive in the marketplace and (2) marketplace information is one of the many factors considered in assessing the reasonableness of our executive compensation program.

The comparative compensation data used in our board of directors analysis is derived solely from competitive market analysis. For the fiscal year ended December 31, 2007, our board of directors reviewed the annual reports or similar information of Chesapeake and Devon Energy Corporation, which are public companies within our industry of comparable or greater size and in Oklahoma City, Oklahoma (collectively, Peer Companies). Due to our organizational structure, comparisons of survey data to the job descriptions of our executive officers is sometimes difficult. Furthermore, the complexities of our operations and the skills needed of our executive officers are, we believe, greater than those of most companies with comparable total revenues. Therefore, we at times target compensation levels of our Peer Companies, which are significantly larger or more developed. Our board of directors believes that targeting this level of compensation helps to meet our overall total rewards strategy and executive compensation objectives outlined above.

Our board of directors believes that these industry specific and general industry comparisons provide the most useful information that is reasonably assessable. The market data described above is used collectively by our board of directors to make informed decisions regarding executive compensation.

Assessment of Individual and Company Performance. While we generally do not adhere to rigid formulas in determining the amount and mix of compensation elements, our board of directors reviews specific company performance measures when determining the size of incentive payouts for our executive officers. In addition, a portion of the incentive payouts are based on evaluations of individual performance. These performance measures are discussed in more detail below.

Elements of our Executive Compensation Program

In furtherance of our compensation objectives, our executive compensation program during 2006 and 2007 consisted of three basic components:

- base salaries;
- discretionary semi-annual cash bonus awards; and
- restricted stock grants.

Base Salaries. Since June 2006, we have provided our executive officers and other employees with an annual base salary to compensate them for services rendered during the year. Our philosophy has been to establish base salaries that are competitive with our Peer Companies. In addition to providing a base salary that is competitive with the market, we target salary compensation to align each position s salary level so that it accurately reflects the relative importance of the position within our organization. To that end, semi-annual salary adjustments are based on a number of individual factors, including:

- the responsibilities of the officer;
- period over which the officer has performed these responsibilities;
- the scope, level of expertise and experience required for the officer s position;
- the strategic impact of the officer s position; and
- potential future contribution and demonstrated individual performance of the officer.

In addition, adjustments are made based on our overall performance and competitive market conditions. Although no particular weight is assigned to these factors, significant emphasis is placed on current market levels and the individual s skills, seniority and previous industry experience, which are evaluated on a case-by-case basis. For example, when reviewing Mr. Ward s experience, the special committee of our board of directors considered that Mr. Ward co-founded and served as President and Chief Operating Officer of Chesapeake, one of our Peer Companies, for 17 years. For our executive officers that were newly hired, significant emphasis was placed on the individual s base salary level at their previous employer.

Cash Bonus Awards. As one way of accomplishing our compensation objectives, our board of directors rewards our executive officers for their contribution to our financial and operational success through the award of semi-annual cash bonuses intended to encourage the attainment of our near-term strategic, operational and financial goals and individual performance measures. The payment of semi-annual bonuses also facilitates the retention of our executive officers because an executive officer must be employed by us on the relevant bonus payment date in order to receive his or her bonus installment payment. In addition, we have paid several of our recently hired named executive officers cash signing bonuses. Cash bonus awards are paid in the discretion of the board of directors upon the recommendation of Mr. Ward.

The factors we consider when determining the amount of any discretionary cash bonus awards are similar to those we consider when setting and adjusting base salaries and no particular weight is assigned to these factors. Currently, the primary measures upon which we base cash bonus decisions are strategic and operational, rather than financial. For example, in 2006 and 2007 we focused on the effective execution of the NEG acquisition, successful access to capital to fund our capital expenditures, including the successful completion of our initial public offering, and the results of our drilling program. These goals were selected as the most appropriate measures upon which to base the bonus decisions because they will result in long term value to our stockholders.

Our board of directors approves the personal goals for our Chief Executive Officer and assesses his performance against those goals in determining the amount of the Chief Executive Officer s cash bonus. Our board of directors expects our Chief Executive Officer to establish and approve personal performance goals for the other executive officers and to review and assess each officer s performance against those goals, reporting the results to our board of directors.

The personal performance goals relate to the achievement of goals unique to the responsibilities of the individual officer, including, for example:

- the successful completion of particular projects;
- the attainment of productivity metrics unique to an officer s responsibilities;
- management of an officer s budgetary responsibilities within specified parameters;
- the acquisition and implementation of new technical knowledge;
- the achievement of individual goals that further those of the company; and
- exceptional performance of functional responsibility.

As reflected in the Bonus column of the Summary Compensation Table, Messrs. Ward, Van Doren and Grubb each received a cash bonus payment in both 2006 and 2007, and Messrs. Coshow and Tipton each received a cash bonus payment in 2007.

We generally did not pay cash bonus awards prior to June 2006.

Restricted Stock Grants. Our board of directors has the discretion to grant restricted stock under our stock plan pursuant to our restricted stock awards program. Our restricted stock awards are granted on a semi-annual basis and typically vest over a four-year vesting period. We anticipate that we will continue to make grants of restricted stock awards on a semi-annual basis. We believe these awards help us to attract highly qualified individuals by providing the potential for the increased returns associated with a high growth company and better aligns the interests of our named executive officers with those of our stockholders. In addition, the gradual vesting period of these awards serves as a tool for the retention of our employees.

In determining the level of equity-based compensation, we make a subjective determination based on the same factors that are used to determine the base salary levels described above.

Other Benefits

In addition to base salaries, cash bonus awards and restricted stock grants, we provide the following forms of compensation:

Health and Welfare Benefits. Our executive officers are eligible to participate in medical, dental, vision, disability insurance and life insurance to meet their health and welfare needs. These benefits are provided so as to assure that we are able to maintain a competitive position in terms of attracting and retaining officers and other employees. This is a fixed component of compensation and the benefits are provided on a non-discriminatory basis to all of our employees in the United States.

Perquisites and Other Personal Benefits. We believe that the total mix of compensation and benefits provided to our executive officers is competitive and perquisites should generally not play a large role in our executive officers total compensation. As a result, the perquisites and other personal benefits we provide to our executive officers are limited. Pursuant to our employment agreement with Mr. Ward, we pay the fees and expenses related to one country club membership in either Amarillo, Texas or Oklahoma City, Oklahoma. In addition, Mr. Ward receives accounting support from certain employees for his personal investments and activities. Mr. Ward reimburses us for half of each such accounting support employee s annual salary and bonus. We have also agreed to provide access to an aircraft at our expense for the personal travel of Mr. Ward and his family and other guests who accompany him. If Mr. Ward does not accompany his family or other guests, he will reimburse us for the variable cost of the use of such aircraft. Mr. Ward will pay all personal income taxes accruing as a result of aircraft use.

401(k) Savings Plan. We have a defined contribution profit sharing/401(k) plan, which is designed to assist our eligible officers and employees in providing for their retirement. We match the contributions of our employees to the plan, in shares of our common stock, at the rate of 100% of up to 15% of an employee s eligible compensation. Employee contributions are immediately 100% vested; however, company contributions vest in equal annual increments over a four-year period.

Deferred Compensation Plan. Effective February 1, 2007, we established a non-qualified deferred compensation plan in order to provide our employees with flexibility in meeting their future income needs and assisting them in their retirement planning. Pursuant to the terms of the deferred compensation plan, eligible highly compensated employees are provided the opportunity to defer income in excess of the IRS annual limitations on qualified 401(k) retirement plans. The 2007 annual 401(k) deferral limit for employees under age 50 is $15,500. Employees turning age 50 or over in 2007 can defer up to $20,500.

Well Participation Program. Mr. Ward also has the opportunity to participate as a working interest owner in the oil and natural gas wells that we drill. The Well Participation Program (WPP) fosters and promotes the development and execution of our business by: (a) retaining and motivating our chief executive officer; (b) aligning the financial rewards and risks of Mr. Ward with the Company more effectively and directly than other performance incentive programs maintained by many of our peers; and (c) imposing on Mr. Ward the same risks we incur in our exploration and production operations.

Employment Agreements, Severance Benefits and Change in Control Provisions

Employment Agreements of Tom L. Ward and Larry K. Coshow. We maintain employment agreements with Mr. Ward, our Chairman, Chief Executive Officer and President and Mr. Coshow, our Executive Vice President Land, to ensure that they will perform their roles for an extended period of time. These agreements are described in more detail elsewhere. Please read Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table Employment Agreements. These agreements provide for severance compensation to be paid if the employment of Mr. Ward or Mr. Coshow is terminated under certain conditions, such as a change in control and termination without cause, each as defined in the agreements.

The employment agreements between us and Mr. Ward and Mr. Coshow and the related severance provisions are designed to meet the following objectives:

> *Change in Control.* In certain scenarios, the potential for merger or being acquired may be in the best interests of our stockholders. As a result, we have agreed to provide severance compensation to Mr. Ward and Mr. Coshow if either employment is terminated following a change in control transaction to promote the ability of Mr. Ward and Mr. Coshow to act in the best interests of our stockholders even though their employment could be terminated as a result of the transaction.
>
> *Termination without Cause.* If we terminate Mr. Ward s or Mr. Coshow s employment without cause, we are obligated to pay certain compensation and other benefits as described in greater detail in Potential Payments upon Termination or Change in Control below. We believe these payments are appropriate because they

represent the general market triggering events found in employment agreements of companies against whom we compete for executive-level talent at the time these provisions were negotiated. It is also beneficial for the Company, Mr. Ward and Mr. Coshow to have mutually agreed to severance packages that are in place prior to any termination event. This provides us with more flexibility to make a change in senior management if such a change is in our and our stockholders best interests.

We believe that the triggering events and severance payments set forth under Mr. Ward s employment agreement are appropriate for the company and fair for stockholders and represent the general market triggering events found in employment agreements of companies against whom we competed for executive-level talent at the time these provisions were negotiated.

We have not entered into an employment agreement with any of our other named executive officers and there was no severance plan affecting our other named executive officers. We intend to enter into additional employment agreements and severance plans with other executive officers during 2008.

Other Matters

Stock Ownership Guidelines and Hedging Prohibition. We do not currently have ownership requirements or a stock retention policy for our named executive officers. However, Mr. Ward s employment agreement requires that the value of the shares of our common stock that he beneficially owns remain above 500% of his annual salary. Based on Mr. Ward s existing salary and the closing price of $30.82 of our common stock on January 22, 2008, Mr. Ward must continue to beneficially own at least 178,456 shares of our common stock. Because Mr. Ward beneficially owns in excess of 35 million shares of our common stock and has shown no indication of reducing his holdings, we have not determined how this provision would work in practice. In the future, if we believed there was a reasonable likelihood of this provision being triggered, we anticipate that our compensation committee at that time would determine the appropriate interpretation of the employment agreement.

We do not have a policy that restricts our executive officers from limiting their economic exposure to our stock. We will continue to periodically review best practices and re-evaluate our position with respect to stock ownership guidelines and hedging prohibitions.

Tax Treatment of Executive Compensation Decisions. Section 162(m) of the Internal Revenue Code limits the deductibility of compensation in excess of $1,000,000 paid to our principal executive officer, our principal financial officer or any of the three other most highly compensated executive officers, unless the compensation qualifies as performance-based compensation. In order to be deemed performance-based compensation, the compensation must be based, among other things, on the achievement of pre-established, objective performance criteria and must be pursuant to a plan that has been approved by our stockholders. Our board of directors has not yet adopted a policy with respect to the limitation under Section 162(m).

Executive Compensation Changes In Fiscal 2007

During 2007, we made the following changes and adjustments to the compensation packages of our named executive officers. We have not modified our general compensation objectives, policies or procedures.

Base Salaries. Effective January 1, 2007, the annualized base salary levels for Messrs. Ward and Grubb increased from $900,000 to $1,050,000 and $325,000 to $400,000, respectively. In approving the increases, Mr. Ward considered the individual factors described above under Elements of our Executive Compensation Program Base Salaries, the successful completion of the NEG acquisition and related financings in November 2006 and subsequent integration of the acquired business, general results of our drilling and exploration program and integration of our new management team.

Effective July 1, 2007, the annualized base salary levels for Messrs. Ward, Van Doren and Grubb increased from $1,050,000 to $1,100,000, $450,000 to $500,000 and $400,000 to $450,000, respectively. In approving the increases, Mr. Ward considered the individual factors described above under Elements of our Executive Compensation Program Base Salaries, integration of our new management team, completion of the NEG Acquisition and successful execution of our March 2007 private placement. Additionally, Mr. Grubb was promoted to Chief Operating Officer and his compensation was adjusted accordingly.

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Cash Bonus Awards. On January 10, 2007, Messrs. Ward, Van Doren and Grubb received bonus compensation in the amount of $950,000, $225,000 and $150,000, respectively. When determining the bonus amounts, our board of directors considered the factors described above under Elements of our Executive Compensation Program Cash Bonus Awards. In addition, our board of directors took into account the same operational factors used in adjusting base salary levels.

On July 11, 2007, Messrs. Ward, Van Doren and Grubb received bonus compensation in the amount of $950,000, $300,000 and $200,000, respectively. When determining the bonus amounts, our board of directors and Mr. Ward considered the factors described above under Elements of our Executive Compensation Program Cash Bonus Awards. In addition, our board of directors and Mr. Ward took into account the same operational factors used in adjusting base salary levels.

Restricted Stock Grants. On January 10, 2007, Messrs. Ward, Van Doren and Grubb were issued restricted stock grants of 300,000 shares, 40,000 shares and 20,000 shares, respectively. The restricted shares vest in equal increments over a four-year period. In determining the level of equity-based compensation, our board of directors considered the factors described above under Elements of our Executive Compensation Program Restricted Stock Grants. In addition, our board of directors took into account the same operational factors used in adjusting base salary levels.

On July 11, 2007, Messrs. Ward, Van Doren and Grubb were issued restricted stock grants of 325,000 shares, 60,000 shares and 25,000 shares, respectively. The restricted shares vest in equal increments over a four-year period. In determining the level of equity-based compensation, our board of directors and Mr. Ward considered the factors described above under Elements of our Executive Compensation Program Restricted Stock Grants. In addition, our board of directors and Mr. Ward took into account the same operational factors used in adjusting base salary levels.

Summary Compensation

The following table sets forth the aggregate compensation awarded to, earned by or paid to our named executive officers for services rendered in all capacities during the fiscal years ended December 31, 2006 and 2007.

Summary Compensation Table

Name and Principal Position	Year	Salary	Bonus	Stock Awards(6)	All Other Compensation(7)	Total
Tom L. Ward	2007	$ 1,067,308	$ 1,900,000	$ 2,210,137	$ 659,689	$ 5,837,134
Chairman, Chief Executive Officer and President(1)	2006	$ 526,154	$ 950,000		$ 374,657	$ 1,850,811
Dirk M. Van Doren	2007	$ 473,077	$ 525,000	$ 370,137	$ 69,580	$ 1,437,794
Executive Vice President and Chief Financial Officer(2)	2006	$ 251,923	$ 225,000	$ 72,512	$ 7,961	$ 557,396
Matthew K. Grubb	2007	$ 420,192	$ 350,000	$ 192,815	$ 44,576	$ 1,007,583
Executive Vice President and Chief Operating Officer(3)	2006	$ 136,250	$ 307,000	$ 34,226	$ 8,944	$ 486,420
Larry K. Coshow	2007	$ 300,000	$ 200,000	$ 132,139	$ 45,230	$ 677,369
	2006	$ 84,231		$ 27,800	$ 104	$ 112,135

Executive Vice President Land(4)						
Todd N. Tipton	2007	$ 311,539	$ 200,000	$ 189,251	$ 444,961	$ 1,145,751
Executive Vice President Exploration(5)	2006	$ 60,000		$ 32,024	$ 1,538	$ 93,562

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(1) Mr. Ward was appointed as our Chairman and Chief Executive Officer on June 8, 2006. Prior to this date, he received no compensation from us. He was also appointed as our President upon the resignation of Mr. Mitchell effective at the end of 2006.

(2) Mr. Van Doren was appointed as our Executive Vice President and Chief Financial Officer on June 8, 2006 and began receiving compensation effective May 15, 2006. Prior to this date, he received no compensation from us.

(3) Mr. Grubb became an employee on August 1, 2006. Prior to this date, he received no compensation from us.

(4) Mr. Coshow became an employee on September 6, 2006. Prior to this date, he received no compensation from us.

(5) Mr. Tipton became an employee on September 28, 2006. Prior to this date, he received no compensation from us.

(6) This column includes the dollar amount of compensation expense we recognized for the fiscal year ended December 31, 2006 and 2007 in accordance with FAS 123R. Pursuant to the Securities and Exchange Commission s rules and regulations, the amounts shown exclude the impact of estimated forfeitures related to service-based vesting conditions. These amounts reflect our accounting expense for these awards, and do not correspond to the actual value that will be recognized by our named executive officers. Assumptions used in the calculation of these amounts are included in Note 18 to our audited financial statements for the fiscal year ended December 31, 2006 included in this prospectus. See Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table below for a description of the material features of these awards.

(7) All Other Compensation consists of the following:

	Year	Club Membership Dues	Accounting Support	Aircraft Use(a)	Life Insurance Premiums	Company Matching Contributions to 401(k) Plan	Deferred Compensation Match	Relocation Expenses or Bonus	Retention or Severance Payment	Employee Participation Plan Allowance	Reimbursement of HSR Fees
cers:											
	2007	$ 5,906	$ 351,725	$ 144,039	$ 230	$ 15,500	$ 142,288				
	2006	$ 2,926	$ 123,960	$ 122,598	$ 173						$ 125,000(b)
Doren	2007			$ 984	$ 230	$ 15,500	$ 52,866				
	2006				$ 173	$ 7,788					
Grubb	2007				$ 230	$ 15,500	$ 28,846				
	2006				$ 173			$ 8,771			
how	2007				$ 230	$ 15,500	$ 29,500				
	2006				$ 104						
on	2007				$ 230	$ 20,500	$ 24,231	$ 400,000			
	2006				$ 104	$ 1,434					

(a) Value based on the incremental cost calculated per hour of use by the named executive officer.

(b) Fees paid by Mr. Ward in connection with obtaining regulatory approval of his purchase of common stock from Mr. Mitchell on June 8, 2006 under the Hart-Scott-Rodino Act. We agreed to reimburse such fees in connection with the approval of Mr. Ward s initial investment in the company.

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Grants of Plan-Based Awards

The following table sets forth information about each grant of an award made to our named executive officers in 2007 under our stock plan pursuant to our restricted stock awards program, including awards, if any, that have been transferred.

Grants of Plan-Based Awards for the Year Ended December 31, 2007

Name	Grant Date	All Other Stock Awards: Number of Shares of Stock or Units
Tom L. Ward	January 10, 2007	300,000
	July 11, 2007	325,000
Dirk M. Van Doren	January 10, 2007	40,000
	July 11, 2007	60,000
Matthew K. Grubb	January 10, 2007	20,000
	July 11, 2007	25,000
Larry K. Coshow	January 10, 2007	15,000
	July 11, 2007	10,000
Todd N. Tipton	January 10, 2007	25,000
	July 11, 2007	15,000

Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table

The following is a discussion of material factors necessary to gain an understanding of the information disclosed in the Summary Compensation Table and the Grants of Plan-Based Awards Table.

Employment Agreements

Employment Agreement of Tom L. Ward. Mr. Ward serves as our President and Chief Executive Officer pursuant to an employment agreement that is currently set to expire on June 30, 2009. Unless either party gives written notice to terminate the agreement, the agreement automatically renews each year on the anniversary of the effective date for a successive three-year term. Mr. Ward s employment agreement entitles him to a base salary of not less than $950,000, subject to increase at the discretion of the board of directors, and the opportunity to earn a cash bonus in the sole discretion of the board of directors or any compensation committee thereof. The employment agreement also provides that we will pay the fees and expenses related to one country club membership in either Amarillo, Texas or Oklahoma City, Oklahoma during the term of the employment agreement. Mr. Ward receives accounting support from our employees for his personal investments and activities. He reimburses us for 50% of the salaries and bonuses paid to the employees primarily engaged in supporting Mr. Ward. We have also agreed to provide access to our aircraft at our expense for the personal travel of Mr. Ward and his family and other guests who accompany him. The employment agreement provides that Mr. Ward is entitled to participate in all of our benefit plans and programs and also contains non-compete and confidentiality provisions in the event Mr. Ward s employment with us is terminated.

Mr. Ward s employment agreement also includes provisions governing the payment of severance benefits if his employment is terminated by us without cause or in connection with a Change in Control. The agreement also addresses termination due to death or disability. For a description of these payments, please read Potential Payments Upon Termination or Change in Control below.

Additionally, if any of the payments or benefits described above are subject to the excise tax imposed by Section 4999 of the Internal Revenue Code of 1986, as amended (the Code), then Mr. Ward is entitled to receive a gross-up payment equal to the amount of excise tax imposed plus all taxes imposed on the gross-up payment.

Employment Agreement of Larry K. Coshow. Mr. Coshow serves as our Executive Vice President Land pursuant to an employment agreement that is currently set to expire on September 2, 2008. Unless we provide written notice to terminate the agreement, the agreement automatically renews each year on the anniversary of the effective date for a successive one year term. Mr. Coshow s employment agreement entitles him to a base salary of not less than $300,000, a minimum bonus payment of $175,000 during the first year of employment, and the opportunity to earn additional bonuses in the sole discretion of the board of directors or any compensation committee thereof. The employment agreement also entitles Mr. Coshow to participate in our medical, life and disability plans.

Mr. Coshow s employment agreement also includes provisions governing the payment of severance benefits if his employment is terminated by us without cause or in connection with a Change of Control. The agreement also addresses termination due to death or disability. For a description of these payments, please read Potential Payments Upon Termination or Change in Control below.

Other Named Executive Officers. Prior to his resignation effective at the end of 2006, Mr. Mitchell was party to an employment agreement with terms identical to those of the employment agreement of Mr. Ward described above. This agreement was entered into in June 2006, simultaneously with the employment agreement with Mr. Ward and terminated upon his resignation. We intend to enter into additional employment agreements with other named executive officers in 2008.

Restricted Stock Awards Program

Following June 2006, our restricted stock award program has continued to be used to retain our named executive officers and better align their interests with those of our stockholders. In addition, the program is intended to enable us to effectively recruit highly qualified individuals by offering the potential for significant return following our initial public offering. Grants of restricted stock are made in the discretion of the board of directors. Please see Outstanding Equity Awards Value at Fiscal Year-End for the complete vesting schedule of restricted stock awards granted during 2007.

Salary and Cash Bonus Awards in Proportion to Total Compensation

The following table sets forth the percentage of each named executive officer s total compensation that we paid in the form of base salary and annual cash bonus awards during 2007.

Name	**Percentage of Total Compensation**
Tom L. Ward	50.8%
Dirk M. Van Doren	69.4%
Matthew K. Grubb	76.4%
Larry K. Coshow	73.8%
Todd N. Tipton	44.6%

Outstanding Equity Awards Value at Fiscal Year-End

The following table reflects all outstanding equity awards held by our named executive officers as of December 31, 2007.

Outstanding Equity Awards as of December 31, 2007

	Stock Awards	
Name	**Number of Shares or Units of Stock That Have Not Vested**	**Market Value of Shares or Units of Stock That Have Not Vested(1)**
Tom L. Ward	625,000(2)	$ 22,412,500
Dirk M. Van Doren	107,500(3)	$ 3,854,950
Matthew K. Grubb	45,000(4)	$ 1,613,700
Larry K. Coshow	25,000(5)	$ 896,500
Todd N. Tipton	40,000(6)	$ 1,434,400

(1) Valuation based on $35.86 per share, the last trading price on December 31, 2007.

(2) Includes 300,000 shares of restricted stock granted January 10, 2007 which shall vest 25% on the 10th day of January in each of the years 2008, 2009, 2010 and 2011; and 325,000 shares of restricted stock granted July 11, 2007 which shall vest 25% on the 11th day of July in each of the years 2008, 2009, 2010 and 2011.

(3) Includes 7,500 shares of restricted stock granted July 1, 2006 which shall vest in 2,500 share increments on the 1st day of July in each of the years 2008, 2009 and 2010; 40,000 shares of restricted stock granted January 10, 2007 which shall vest 25% on the 10th day of January in each of the years 2008, 2009, 2010 and 2011; and 60,000 shares of restricted stock granted July 11, 2007 which shall vest 25% on the 11th day of July in each of the years, 2008, 2009, 2010 and 2011.

(4) Includes 20,000 shares of restricted stock granted January 10, 2007 which shall vest 25% on the 10th day of January in each of the years 2008, 2009, 2010 and 2011; and 25,000 shares of restricted stock granted July 11, 2007 which shall vest 25% on the 11th day of July in each of the years 2008, 2009, 2010 and 2011.

(5) Includes 15,000 shares of restricted stock granted January 10, 2007 which shall vest 25% on the 10th day of January in each of the years 2008, 2009, 2010 and 2011; and 10,000 shares of restricted stock granted July 11, 2007 which shall vest 25% on the 11th day of July in each of the years 2008, 2009, 2010 and 2011.

(6) Includes 25,000 shares of restricted stock granted January 10, 2007 which shall vest 25% on the 10th day of January in each of the years 2008, 2009, 2010 and 2011; and 15,000 shares of restricted stock granted July 11, 2007 which shall vest 25% on the 11th day of July in each of the years 2008, 2009, 2010 and 2011.

Option Exercises and Stock Vested

The following table reflects the restricted stock of our named executive officers that vested during 2007. No stock options were outstanding in 2007.

Option Exercises and Stock Vested for the Year Ended December 31, 2007

	Stock Awards	
Name	**Number of Shares Acquired on Vesting**	**Value Realized on Vesting**
Tom L. Ward		
Dirk M. Van Doren	2,500	$ 89,650(1)
Matthew K. Grubb		
Larry K. Coshow		
Todd N. Tipton		

(1) Valuation based on $35.86 per share, the last trading price on December 31, 2007.

Potential Payments Upon Termination or Change in Control

Severance Under Employment Agreement of Tom L. Ward

Termination Other Than For Cause. In the event we terminate Mr. Ward s employment other than for Cause (as defined below), Mr. Ward is entitled to receive (1) his base salary as in effect on the date of termination during the remaining term of the employment agreement or through the expiration date of the agreement and (2) any vacation pay accrued through the date of termination. If Mr. Ward was terminated other than for Cause on December 31, 2007, his severance would equal $1,650,000 (base salary for 18 months, which is the remaining term of his employment agreement), and the maximum value of his accrued vacation (assuming he took no time off during the year) would be $105,769.

For purposes of his employment agreement, the term Cause means (1) the willful and continued failure of Mr. Ward to perform substantially his duties after a written demand for substantial performance is delivered to him by the board of directors which specifically identifies the manner in which the Board believes he has not substantially performed his duties or (2) the willful engaging by Mr. Ward in illegal conduct, gross misconduct or a clearly established violation of our written policies and procedures, in each case which is materially and demonstrably injurious to us. An act or failure to act, on the part of Mr. Ward, will not be considered willful unless it is done, or omitted to be done, by him in bad faith or without reasonable belief that the action or omission was in our best interests.

Termination in Connection with Change in Control. In the event that Mr. Ward s employment is terminated within one year of a Change in Control event (as defined below) other than for Cause, death or disability, Mr. Ward is entitled to receive (1) a single, lump sum severance payment within 10 days of termination equal to 3 times his base salary for the last 12 calendar months and bonus paid (based on an average of the last three years annual bonuses or such lesser number of years as he was employed) and (2) any applicable gross-up payment (as defined below). If the foregoing amount is not paid within ten days after the Change in Control, the unpaid amount will bear interest at the per annum rate of 12%. If at the time of a Change in Control, Mr. Ward is a specified employee as defined in regulations under Section 409A of the Code, such payment will be made on the first day which is more than six months following the Change in Control Termination. To the extent that any payment or distribution is subject to excise tax under Section 4999 of the Code or any other interest of penalties related to such excise tax (collectively Excise Tax), the agreement provides we will pay an additional amount (the Gross-Up Payment) such that after payment by Mr. Ward of all taxes on the Gross-Up Payment, he will retain an amount of the Gross-Up Payment equal to the Excise Tax. If Mr. Ward were terminated within one year of a Change in Control event other than for Cause, death or disability, his severance would equal $8,901,924 (3 times the sum of his base salary in 2007 of $1,067,308 plus his bonus of $1,900,000) plus a Gross-Up Payment equal to $3,677,332 and an interest payment equal to $353,001, for a total payment of $12,932,257.

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Under the employment agreement, a Change in Control is defined as follows: (1) the acquisition of any individual, entity or group (within the meaning of Section 13(d)(3) or 14(d)(2) of the Securities exchange Act of 1934, as amended (the Exchange Act)) (a Person), other than Executive or his affiliates or Malone Mitchell 3rd or his affiliates (the Exempt persons), of beneficial ownership (within the meaning of Rule 13d-3 promulgated under the Exchange Act) of 40% or more of either (i) the then outstanding shares of our common stock of (the Outstanding Company Common Stock) or (ii) the combined voting power of the then outstanding voting securities of the company entitled to vote generally in the election of directors (the Outstanding Company Voting Securities); (2) the individuals who, as of the date hereof, constitute the board of directors (the Incumbent Board) cease for any reason to constitute at least a majority of the board of directors. Any individual becoming a director subsequent to the date hereof whose election, or nomination for election by our stockholders, is approved by a vote of at least a majority of the directors then comprising the Incumbent Board will be considered a member of the Incumbent Board as of the date hereof, but any such individual whose initial assumption of office occurs as a result of an actual or threatened election contest with respect to the election or removal of directors or other actual or threatened solicitation of proxies or consents by or on behalf of a person other than the Incumbent Board will not be deemed a member of the Incumbent Board as of the date hereof; (3) the consummation of a reorganization, merger, consolidation or sale or other disposition of all or substantially all of the assets of the company (a Business Combination), unless following such Business Combination: (i) the individuals and entities who were the beneficial owners, respectively, of the Outstanding Company Common Stock and Outstanding Company Voting Securities immediately prior to such Business Combination beneficially own, directly or indirectly, more than 60% of respectively, the then outstanding shares of common stock and the combined voting power of the then outstanding voting securities entitled to vote generally in the election of directors, as the case may be, of the corporation resulting from such Business Combination (including, without limitation, a corporation which as a result of such transaction owns the company or all or substantially all of our assets either directly or through one or more subsidiaries) in substantially the same proportions as their ownership, immediately prior to such Business Combination of the Outstanding Company Common Stock and Outstanding Company Voting Securities, as the case may be, (ii) no Person (excluding any corporation resulting from such Business Combination or any employee benefit plan (or related trust) of the company or such corporation resulting from such Business Combination) other than one or more of the Exempt Persons beneficially owns, directly or indirectly, 40% or more of, respectively, the then outstanding voting securities of such corporation except to the extent that such ownership existed prior to the Business Combination and (iii) at least a majority of the members of the board of directors of the corporation resulting from such Business Combination were members of the Incumbent Board at the time of the execution of the initial agreement, or of the action of the Board, providing for such Business Combination; or (4) the approval by our stockholders of a complete liquidation or dissolution of the company.

In addition, notwithstanding any provision to the contrary in any option agreement, restricted stock agreement, plan or other agreement relating to equity based compensation, in the event of a termination without Cause or in connection with a Change in Control, all Mr. Ward s units, stock options, incentive stock options, performance shares, stock appreciation rights and restricted stock (collectively awards) will immediately become 100% vested. Further, Mr. Ward s right to exercise any previously unexercised options will not terminate until the latest date on which such option would expire but for Mr. Ward s termination. To the extent we are unable to provide for one or both of the foregoing rights, we will provide in lieu thereof a lump-sum cash payment equal to the difference between the total value of such awards with the foregoing rights and the total value without the foregoing rights.

Termination for Cause. In the event Mr. Ward is terminated for Cause, we will have no further obligation to provide further payments or benefits. If Mr. Ward desires to voluntarily terminate, he must give 90 days notice of his intent to termination during which time he can use accrued vacation time or be paid for such days. If Mr. Ward was terminated for Cause on December 31, 2007, the maximum value of his accrued vacation time (assuming he took no time off during the year) would be $105,769.

Voluntary Termination. In the event Mr. Ward voluntarily terminates with or without Cause, we have no further obligations except for any obligations expressly surviving termination of employment.

Termination due to Disability. If Mr. Ward s employment is terminated due to disability, then he is entitled to receive base salary through the remaining term of his employment agreement or through the Expiration Date of the agreement. If Mr. Ward was terminated due to disability on December 31, 2007, his severance would equal $1,650,000 (base salary for 18 months, which is the remaining term of his employment agreement).

Termination due to Death. In the event Mr. Ward s employment terminates due to death, then he will be entitled to receive (1) base salary payment for 12 months after termination and (2) any accrued benefits. If Mr. Ward was terminated due to death on December 31, 2007, his severance would equal $1,100,000 (12 months salary) plus the maximum value of his accrued vacation (assuming he took no time off during the year) equal to $105,769.

Severance Under Employment Agreement of Larry K. Coshow

Termination Other Than For Cause. In the event we terminate Mr. Coshow s employment other than for Cause (as defined below), Mr. Coshow is entitled to receive his base salary as in effect on the date of termination during the remaining term of the employment agreement or through the expiration date of the agreement. If Mr. Coshow was terminated other than for Cause on December 31, 2007, his severance would equal approximately $200,000 (base salary for 8 months, which is the remaining term of his employment agreement).

For purposes of his employment agreement, the term Cause means (A) Mr. Coshow s material breach or threatened breach of the employment agreement; (B) Mr. Coshow fails to substantially perform his duties under his employment agreement; (C) the misappropriation or fraudulent conduct by Mr. Coshow with respect to our assets or operations; (D) Mr. Coshow s willful disregard of the instructions of the Board or Mr. Coshow s material neglect of duties or failure to act, other than by reason of disability or death; (E) Mr. Coshow s personal misconduct which injures us substantially; or (F) the conviction of Mr. Coshow for, or a plea of guilty or no contest to, a felony or any crime involving fraud, theft or dishonesty.

Termination in Connection with Change in Control. In the event that Mr. Coshow s employment is terminated within one year of a Change in Control event (as defined below) other than for Cause, death or disability, Mr. Coshow is entitled to receive a single, lump sum severance payment within 10 days of termination equal to his base salary for the last 12 calendar months and bonus paid (based on an average of the last three years annual bonuses or such lesser number of years as he was employed). If the foregoing amount is not paid within ten days after the Change in Control, the unpaid amount will bear interest at the per annum rate of 12%. If at the time of a Change in Control, Mr. Coshow is a specified employee as defined in the regulations under Section 409A of the Code, such payment will be made on the first day which is more than six months following the Change in Control Termination. If Mr. Coshow were terminated within one year of a Change in Control event other than for Cause, death or disability, his severance would equal $500,000 (the sum of his base salary in 2007 of $300,000 plus his bonus of $200,000) plus an interest payment of $30,000, for a total payment of $530,000. The right to this termination compensation upon Change in Control is subject to Mr. Coshow s execution of a severance agreement which will operate as a release of all legally waivable claims against us. Such payment is further conditioned upon Mr. Coshow s compliance with all of the provisions of his employment agreement, including all post-employment obligations.

Under the employment agreement, a Change in Control is defined as follows: (1) the acquisition of any individual, entity or group (within the meaning of Section 13(d)(3) or 14(d)(2) of the Securities exchange Act of 1934, as amended (the Exchange Act)) (a Person), other than Executive or his affiliates or Tom L. Ward or his affiliates (the Exempt persons), of beneficial ownership (within the meaning of Rule 13d-3 promulgated under the Exchange Act) of 40% or more of either (i) the then outstanding shares of our common stock of (the Outstanding Company Common Stock) or (ii) the combined voting power of the then outstanding voting securities of the company entitled to vote generally in the election of directors (the Outstanding Company Voting Securities); (2) the individuals who, as of the date hereof, constitute the board of directors (the Incumbent Board) cease for any reason to constitute at least a majority of the board of directors. Any individual becoming a director subsequent to the date hereof whose election, or nomination for election by our stockholders, is approved by a vote of at least a majority of the directors then comprising the

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Incumbent Board will be considered a member of the Incumbent Board as of the date hereof, but any such individual whose initial assumption of office occurs as a result of an actual or threatened election contest with respect to the election or removal of directors or other actual or threatened solicitation of proxies or consents by or on behalf of a person other than the Incumbent Board will not be deemed a member of the Incumbent Board as of the date hereof; (3) the consummation of a reorganization, merger, consolidation or sale or other disposition of all or substantially all of the assets of the company (a Business Combination), unless following such Business Combination: (i) the individuals and entities who were the beneficial owners, respectively, of the Outstanding Company Common Stock and Outstanding Company Voting Securities immediately prior to such Business Combination beneficially own, directly or indirectly, more than 60% of respectively, the then outstanding shares of common stock and the combined voting power of the then outstanding voting securities entitled to vote generally in the election of directors, as the case may be, of the corporation resulting from such Business Combination (including, without limitation, a corporation which as a result of such transaction owns the company or all or substantially all of our assets either directly or through one or more subsidiaries) in substantially the same proportions as their ownership, immediately prior to such Business Combination of the Outstanding Company Common Stock and Outstanding Company Voting Securities, as the case may be, (ii) no Person (excluding any corporation resulting from such Business Combination or any employee benefit plan (or related trust) of the company or such corporation resulting from such Business Combination) other than one or more of the Exempt Persons beneficially owns, directly or indirectly, 40% or more of, respectively, the then outstanding voting securities of such corporation except to the extent that such ownership existed prior to the Business Combination and (iii) at least a majority of the members of the board of directors of the corporation resulting from such Business Combination were members of the Incumbent Board at the time of the execution of the initial agreement, or of the action of the Board, providing for such Business Combination; or (4) the approval by our stockholders of a complete liquidation or dissolution of the company.

In addition, notwithstanding any provision to the contrary in any option agreement, restricted stock agreement, plan or other agreement relating to equity based compensation, in the event of a termination in connection with a Change in Control, all Mr. Coshow s units, stock options, incentive stock options, performance shares, stock appreciation rights and restricted stock (collectively awards) will immediately become 100% vested. Further, Mr. Coshow s right to exercise any previously unexercised options will not terminate until the latest date on which such option would expire but for Mr. Coshow s termination. To the extent we are unable to provide for one or both of the foregoing rights, we will provide in lieu thereof a lump-sum cash payment equal to the difference between the total value of such awards with the foregoing rights and the total value without the foregoing rights. The right to this termination compensation is subject to Mr. Coshow s execution of our severance agreement which will operate as a release of all legally waivable claims against us. Such payment is further conditioned upon Mr. Coshow s compliance with all of the provisions of his employment agreement, including all post-employment obligations

Termination for Cause. In the event Mr. Coshow is terminated for Cause, we will have no further obligation to provide further payments or benefits. If Mr. Coshow desires to voluntarily terminate, he must give 90 days notice of his intent to terminate.

Voluntary Termination. In the event Mr. Coshow voluntarily terminates with or without Cause, we have no further obligations except for any obligations expressly surviving termination of employment.

Termination due to Disability. If Mr. Coshow s employment is terminated due to disability, then he is entitled to receive base salary through the remaining term of his employment agreement or through the Expiration Date of the agreement. If Mr. Coshow was terminated due to disability on December 31, 2007, his severance would equal approximately $200,000 (base salary for 8 months, which is the remaining term of his employment agreement) which will be reduced by any benefits payable under any disability plans provided by us pursuant to his employment agreement.

Termination due to Death. In the event Mr. Coshow s employment terminates due to death, then he will be entitled to receive base salary payment for 12 months after termination. If Mr. Coshow was terminated due to death on December 31, 2007, his severance would equal $300,000 (12 months salary).

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Stock Plan

Upon disability (as defined below) or death of any named executive officer, any benefits awarded under the 2005 Stock Plan will become vested to the extent that vesting would have occurred had the named executive officer remained a participant for a period of 12 months after termination. Disability is defined as the inability to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment which can be expected to result in death or which has lasted or can be expected to last for a continuous period of 12 months. An option or stock appreciation right that is vested pursuant to disability must be exercised within 18 months or such shorter time as specified in the grant from the date on which termination occurred or the option or stock appreciation right will terminate. If a named executive officer dies who was no longer a participant at the time of death and his options or stock appreciation rights have not yet expired, those options or stock appreciation rights may be exercised within 12 months following death. The following table sets forth the value of shares of restricted stock for each named executive officer that would vest within the 12 months following his death or disability on December 31, 2007. Please see Outstanding Equity Awards Value at Fiscal Year-End for the complete vesting schedule.

	Number of Shares Vesting Within 12 Months of December 31, 2007	**Market Value of Shares Vesting(1)**
Tom L. Ward	156,250	$ 5,603,125
Dirk M. Van Doren	27,500	$ 986,150
Matthew K. Grubb	11,250	$ 403,425
Larry K. Coshow	6,250	$ 224,125
Todd N. Tipton	10,000	$ 358,600

(1) Valuation based on $35.86 per share, the last trading price on December 31, 2007.

Upon a Change in Control, the board of directors may take any action with respect to outstanding Awards under the Plan as it deems appropriate, which action may vary among Awards granted to individual participants.

Description of Stock Plan

Scope

Our board of directors and stockholders have approved our Stock Plan (the Plan). The Plan authorizes the granting of stock options to purchase common stock, stock appreciation rights, restricted stock, phantom stock and other stock-based awards to our employees, directors and consultants. In addition, the Plan authorizes cash-denominated awards that may be settled in cash, stock or any combination thereof. The purpose of the Plan is to attract, retain and provide incentives to our officers, other associates, directors and consultants and to thereby increase overall stockholder value.

The Plan authorizes 7,074,252 shares of common stock to be used for awards. As of December 31, 2007, approximately 2.2 million shares had been awarded as restricted stock subject to vesting periods of one, four and seven years (other than shares cancelled or forfeited), and 4.9 million shares, representing 34.6% of the outstanding shares of common stock as of December 31, 2007, are available to be used for future awards. If an award made under the Plan expires, terminates or is forfeited, canceled, settled in cash without issuance of shares of common stock covered by the award, or if award shares are used to pay for other award shares, those shares will be available for future awards under the Plan.

Eligibility

Our employees, directors and consultants may be selected by the compensation committee to receive awards under the Plan. In the discretion of the compensation committee, an eligible person may receive an award in the form of a stock option, stock appreciation right, restricted stock award, phantom stock, other stock-based award or any combination thereof, including a cash-based award, and more than one award may be granted to an eligible person.

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Stock Options

The Plan authorizes the award of both non-qualified and incentive stock options (ISO). Under the Plan and pursuant to awards made thereunder, common stock may be purchased at a fixed exercise price during a specified time. Unless otherwise provided in the award agreement, the exercise price of each share of common stock covered by a stock option shall not be less than the fair market value of the common stock on the date of the grant of such stock option, and one-third (1/3) of the shares covered by the stock option shall become exercisable on the first anniversary of its grant and an additional one-third (1/3) of such shares shall become exercisable on each of the second and third anniversaries of its grant. A limited number of options and SARs may be granted with an exercise price below fair market value on the date of grant, but not less than 75% of fair market value.

Under the Plan, an ISO may be exercised at any time during the exercise period established by the compensation committee, except that (i) no ISO may be exercised more than three months after employment with us terminates by reason other than death or disability and (ii) no ISO may be exercised more than one year after employment with us terminates by reason of death or disability. The aggregate fair market value (determined at the time of the award) of the common stock with respect to which ISOs are exercisable for the first time by any employee during any calendar year may not exceed $100,000. The term of each ISO is determined by the compensation committee, but in no event may such term exceed 10 years from the date of grant (or five years in the case of ISOs granted to stockholders owning 10% or more of our outstanding shares of common stock). The exercise price of ISOs cannot be less than the fair market value of the common stock on the date of the grant (or 110% of the fair market value of the common stock on the date of grant in the case of ISOs granted to stockholders owning 10% or more of our outstanding shares of common stock). The exercise price of options may be paid in cash, in shares of common stock through a cashless exercise program with previously owned common stock or by such other methods as the compensation committee deems appropriate.

Stock Appreciation Rights

The Plan authorizes the grant of stock appreciation rights (SARs). The SARs may be granted either separately or in tandem with options. An SAR entitles the holder to receive an amount equal to the excess of the fair market value of a share of common stock at the time of exercise of the SAR over the option exercise price or other specified amount (or deemed option price in the event of an SAR that is not granted in tandem with an option), multiplied by the number of shares of common stock subject to the option or deemed option as to which the SAR is being exercised (subject to the terms and conditions of the option or deemed option). An SAR may be exercised at any time when the option or deemed option to which it related may be exercised and will terminate no later than the date on which the right to exercise the tandem option (or deemed option) terminates (or is deemed to terminate).

Restricted Stock

Restricted stock awards are grants of common stock made to eligible persons subject to restrictions, terms and conditions as established by the compensation committee. The grants of restricted stock are issued and outstanding shares from the date of the grant, but subject to forfeiture. An eligible person will become the holder of shares of restricted stock free of all restrictions if he or she complies with all restrictions, terms and conditions. Otherwise, the shares will be forfeited. The eligible persons will not have the right to vote the shares of restricted stock until all restrictions, terms and conditions are satisfied.

Other Stock Based Awards

The compensation committee may grant other stock based awards, upon such terms as it may elect.

Dollar-Denominated Awards

The compensation committee may grant an award in terms of a specific dollar amount on such terms as it may elect. Upon the vesting of such award, the award earned may be paid in cash, stock or any combination thereof as the compensation committee may choose.

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Adjustments

In the event of any changes in the outstanding shares of common stock by reason of any stock dividend, split, spinoff, recapitalization, merger, consolidation, combination, exchange of shares or other similar change, the aggregate number of shares with respect to which awards may be made under the Plan, and the terms and the number of shares of any outstanding option, restricted stock or other stock-based award, may be equitably adjusted by the compensation committee in its sole discretion.

Change of Control

Upon a change in control, which is defined in the Plan to include certain third-party acquisitions of 50% or more of our then outstanding common stock or the combined voting power of the then outstanding common stock entitled to vote generally in the election of directors, changes in the composition of the board of directors, stockholder approval of certain significant corporate transactions such as a reorganization, merger, consolidation, sale of assets or the liquidation or dissolution of the company, the board of directors may take any action with respect to outstanding Awards under the Plan as it deems appropriate, which action may vary among Awards granted to individual participants.

Administration

The Plan is administered by the board of directors or, if directed by the board of directors, the compensation committee of the board of directors or another committee designated by the board of directors (in each event, the compensation committee). The compensation committee makes determinations with respect to the participation of employees, directors and consultants in the Plan and, except as otherwise required by law or the Plan, the grant terms of awards, including vesting schedules, retirement and termination rights, payment alternatives such as cash, stock, contingent award or other means of payment consistent with the purposes of the Plan, and such other terms and conditions as the board or the compensation committee deems appropriate. The compensation committee has the authority at any time to provide for the conditions and circumstances under which awards shall be forfeited. The compensation committee has the authority to accelerate the vesting of any award and the time at which any award becomes exercisable.

Termination and Amendment

The board may at any time terminate the Plan or from time to time make such modifications or amendments of the Plan as it may deem advisable; provided, however, that the board shall not make any amendments to the Plan which require stockholder approval under applicable law, rule or regulation unless approved by the requisite vote of our stockholders. No termination, modification or amendment of the Plan may adversely affect the rights conferred by an award without the consent of the recipient thereof.

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth certain information with respect to the beneficial ownership of our common stock as of December 31, 2007 by:

- each stockholder known by us to be the beneficial owner of more than 5% of the outstanding shares of our common stock;
- our current directors;
- our named executive officers; and
- all of our directors and executive officers as a group.

Unless otherwise indicated in the footnotes to this table and subject to community property laws where applicable, we believe that each of the stockholders named in this table has sole voting and investment power with respect to the shares indicated as beneficially owned.

	Number of Shares Beneficially Owned	**Percentage of Shares Beneficially Owned**
Tom L. Ward	35,702,707(1)	24.7%
Dirk M. Van Doren	134,009	*
Matthew K. Grubb	5,000	*
Larry K. Coshow	3,750	*
Todd N. Tipton	6,330	*
Bill Gilliland	1,349,878(2)	*
Dan Jordan	1,001,389	*
Roy T. Oliver, Jr.	1,001,389(3)	*
Stuart W. Ray		
D. Dwight Scott	(4)	
Jeffrey Serota	(5)	
Entities affiliated with Ares Management LLC	13,333,333(6)	9.4%
N. Malone Mitchell, 3rd	17,280,214(7)	12.1%
All directors and named executive officers as a group	39,204,452(1)	27.1%

* Less than 1%.

(1) Includes (a) 9,246,624 shares of common stock and 2,680,677 shares of common stock issuable upon conversion of convertible preferred stock held by TLW Properties, L.L.C. for which Mr. Ward exercises voting and dispositive power, (b) 79,000 shares held through an IRA and (c) 13,000 shares of common stock held by Mr. Ward s minor child. Does not include 6,509,601 shares held through a family trust.

(2) Such shares are held by Gillco Energy, LP, for which Mr. Gilliland exercises voting and dispositive power.

(3) Such shares are held by Oliver Active Investments, LLC, for which Mr. Oliver exercises voting and dispositive power.

(4) Mr. Scott serves as a managing director of GSO Capital Partners LP, the investment manager for each of GSO Credit Opportunities Fund (Helios), L.P. (GSO Helios), GSO Special Situations Overseas Master Fund Ltd. (GSO Overseas) and GSO Special Situations Fund LP (GSO SS and, together with GSO Helios and GSO Overseas, the GSO Funds). Each of GSO Helios (286,354 shares), GSO Overseas (405,262 shares) and GSO SS (419,495 shares) are the holders of record of our common stock. As investment manager of the GSO Funds, GSO Capital Partners LP is vested with investment discretion with respect to investments held by the GSO Funds. GSO LLC (GSO General Partner) is the general partner of GSO Capital Partners LP, and in that capacity, directs the operations of GSO Capital Partners LP. Bennett J. Goodman (Mr. Goodman), J. Albert Smith III (Mr. Smith) and Douglas I. Ostrover

(Mr. Ostrover and together with Mr. Goodman and Mr. Smith, the GSO Managing Members) are the managing members of the General Partner, and in that capacity, direct the General Partner s operations. Each of the GSO Funds, GSO Capital Partners LP, General Partner and the Managing Members (collectively, the GSO Persons) may be deemed a beneficial owners of our common stock. However, the foregoing should not be deemed to constitute an admission that any of the GSO Persons are the beneficial owners of any of common stock owned by the GSO Funds. Mr. Scott disclaims any beneficial ownership of the shares of our common stock owned by the GSO Funds.

(5) Mr. Serota is a senior partner in the Private Equity Group of Ares Management LLC (Ares Management), a private investment management firm that indirectly controls Ares Corporate Opportunities Fund II, L.P. (ACOF II), Ares SandRidge, L.P. (Ares SandRidge), Ares SandRidge 892 Investors, L.P. (Ares 892 Investors) and Ares SandRidge Co-Invest, LLC (together with Ares SandRidge and Ares 892 Investors, the ACOF II AIVs). Mr. Serota disclaims beneficial ownership of the shares owned by ACOF II and the ACOF II AIVs, except to the extent of any pecuniary interest therein.

(6) According to a Schedule 13G filed with the SEC on November 26, 2007, the shares of common stock listed in the table above are owned as follows: ACOF II 7,376,636 shares; Ares SandRidge 1,996,851 shares; Ares 892 Investors 3,126,513 shares; and Ares SandRidge Co-Invest, LLC 833,333 shares. The general partner of ACOF II and certain of the ACOF II AIVs is ACOF Management II, L.P. (ACOF Management II) and the general partner of ACOF Management II is ACOF Operating Manager II, L.P. (ACOF Operating Manager II). ACOF Operating Manager II is indirectly controlled by Ares Management, which, in turn, is indirectly controlled by Ares Partners Management Company LLC. Each of the foregoing entities (collectively, the Ares Entities) and the partners, members and managers thereof, other than ACOF II and the ACOF II AIVs, disclaims beneficial ownership of the shares of common stock owned by ACOF II and the ACOF II AIVs, except to the extent of any pecuniary interest therein. The address of each Ares Entity is 1999 Avenue of the Stars, Suite 1900, Los Angeles, CA 90067.

(7) Includes (a) 485,630 shares issuable upon conversion of convertible preferred stock and 4,548 shares of common stock held by Dalea Partners for which Mr. Mitchell exercises voting and dispositive power and (b) 5,000 shares held by Mr. Mitchell s minor child. The address for Mr. Mitchell is 4801 Gaillardia Parkway, Suite 225, Oklahoma City, Oklahoma 73142.

SELLING STOCKHOLDERS

No stockholder may offer or sell shares of our common stock under this prospectus unless such stockholder has notified us of his or her intention to sell shares of our common stock and this prospectus has been declared effective by the SEC and remains effective at the time such selling stockholder offers or sells such shares. We are required to amend this prospectus to reflect material developments in our business, financial position and results of operations. Each time we file an amendment to this prospectus with the SEC, it must first be declared effective prior to the offer or sale of shares of our common stock by the selling stockholders.

The selling stockholders listed below may from time to time offer and sell pursuant to this prospectus all of the common shares covered by this prospectus as indicated in the table below, including shares issuable upon conversion of our convertible preferred stock. The selling stockholders may not offer or sell any of our convertible preferred stock pursuant to this prospectus. The common shares being offered by the selling stockholders are outstanding or issuable upon conversion of outstanding convertible preferred stock, and were, or will be, originally issued as follows:

- common shares issued in connection with a private placement to eligible investors in December 2005 and January 2006;

- common shares that may be issued upon conversion of our convertible preferred stock issued to eligible investors in November 2006;

- common shares issued in connection with a private placement of common shares and warrants to purchase our convertible preferred stock to eligible institutional investors in November 2006;

- common shares issued in connection with a private placement to eligible institutional investors in March 2007; and

- common shares issued in March 2007 to certain holders of our convertible preferred stock pursuant to the contractual preemptive rights exercised in connection with the March 2007 private placement of common shares.

The following table, which we have prepared based on information provided to us by the applicable selling stockholder, sets forth the name, the number of shares of common stock beneficially owned by the selling stockholders intending to sell our common stock and the number of shares of common stock to be offered. Unless set forth below, none of the selling stockholders selling in connection with the prospectus has held any position or office with, been employed by, or otherwise has had a material relationship with us or any of our affiliates during the three years prior to the date of the prospectus.

Name of Beneficial Owner	Number of Shares Beneficially Owned Prior to Offering	Number of Shares Being Offered	Number of Shares Beneficially Owned After Offering	Percentage of Shares Beneficially Owned Prior	Percentage of Shares Beneficially Owned After Offering

				to Offering	
Fund managed by Moore Capital Management, LLC(1)	3,236,482(2)	3,186,482(2)	50,000	2.24%	*
UBS O Connor LLC F/B/O O Connor(3) Pipes Corporate Strategies Master Limited	72,856(4)	72,856(4)	0	*	
UBS O Connor LLC F/B/O O Connor(3) Global Convertible Arbitrage Master Limited	153,657(5)	153,657(5)	0	*	
UBS O Connor LLC F/B/O O Connor(3) Global Convertible Arbitrage II Master Limited	16,317(6)	16,317(6)	0	*	
Ospraie SandRidge Holdings LLC(7)	750,184(8)	750,184(8)	0	*	
Ospraie Special Opportunities Master Alternative Holdings LLC(9)	750,184(8)	750,184(8)	0	*	
LB I Group Inc.(10)	2,185,339(11)	2,185,339(11)	0	1.52%	
Credit Suisse Securities (USA) LLC(12)	215,195(13)	215,195(13)	0	*	
John D. Arnold	600,155(14)	600,155(14)	0	*	
Total	7,980,369	7,930,369	50,000	5.39%	*

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(1) Shares held by Moore Macro Fund, LP (MMF). The address for MMF is c/o Moore Capital Management, LLC, 1251 Avenue of the Americas, 53rd Floor, New York, New York 10020. Moore Capital Management, LLC (MCM), a New York limited liability company, serves as discretionary investment manager of MMF, and in such capacity may be deemed the beneficial owner of the portfolio assets held for the account of MMF. Mr. Louis M. Bacon serves as the chairman, chief executive officer and director of MCM. As a result, Mr. Bacon may be deemed to be the indirect beneficial holder of the shares indicated.

(2) Includes 2,428,149 shares of common stock issuable upon conversion of convertible preferred stock.

(3) The selling stockholder is a fund which cedes investment control to UBS O Connor LLC (the Investment Manager). The Investment Manager makes all the investment decisions and is a wholly owned subsidiary of UBS AG, a publicly traded entity.

(4) Includes 72,856 shares of common stock issuable upon conversion of convertible preferred stock.

(5) Includes 153,657 shares of common stock issuable upon conversion of convertible preferred stock.

(6) Includes 16,317 shares of common stock issuable upon conversion of convertible preferred stock.

(7) The Ospraie Fund L.P. (Ospraie LP) is the managing member of Ospraie Sandridge Holdings LLC (Ospraie Sandridge) and in that capacity directs its operations, including the power to direct the investment activities of Ospraie Sandridge. Ospraie Group LLC (Ospraie Group) is the general partner of Ospraie LP and in that capacity directs its operations. Mr. Dwight Anderson is the managing member of Ospraie Group and in that capacity directs its operations. Mr. Anderson disclaims any beneficial ownership in such securities except to the extent of any pecuniary interest therein.

(8) Includes 607,029 shares of common stock issuable upon conversion of convertible preferred stock.

(9) Pursuant to an investment management agreement, Ospraie Advisors, L.P., (Ospraie Advisors) serves as investment manager to Ospraie Special Opportunities Master Alternative Holdings LLC (OSOMAH). As such, Ospraie Advisors has been granted investment discretion over portfolio investments held for the account of OSOMAH. Ospraie Advisors, LLC is the general partner of Ospraie Advisors. Ospraie Management, LLC (Ospraie Management) is the managing member of Ospraie Advisors, LLC. Ospraie Holding I, L.P. (Ospraie Holding) is the managing member of Ospraie Management. Ospraie Management, Inc. (Ospraie Inc.) is the general partner of Ospraie Holding. Mr. Dwight Anderson is the President and controlling equity owner of Ospraie Inc. and, in such capacity, may be deemed to have voting and dispositive power over the securities held for the account of OSOMAH. Mr. Anderson disclaims any beneficial ownership in such securities except to the extent of any pecuniary interest therein. Mr. John Duryea is a portfolio manager at Ospraie Advisors and, in such capacity, may be deemed to have voting and dispositive power over the securities held for the account of OSOMAH. Mr. Duryea disclaims any beneficial ownership in such securities except to the extent of any pecuniary interest therein. Additionally, Ospraie Associates LLC (Manager) serves as the non-member manager to OSOMAH and in that capacity directs its operations. Ospraie Associates Holdings LLC (Associates) is the managing member of Manager and in that capacity directs its operations. Ospraie Group LLC (Ospraie Group) is the managing member of Associates and in that capacity directs its operations. Mr. Anderson is the managing member of Ospraie Group and in that capacity directs its operations.

(10) LB I Group Inc. is a wholly-owned subsidiary of Lehman Brothers Inc., which is a registered broker-dealer. LB I Group Inc. has represented to us that it is not acting as an underwriter in this offering, it purchased the shares

it is offering under this prospectus in the ordinary course of business, and at the time of such purchase, it had no agreements or understandings, directly or indirectly, with any person to distribute the securities. Lehman Brothers Holdings Inc., a public reporting company, is the parent company of Lehman Brothers Inc.

(11) Includes 2,185,339 shares of common stock issuable upon conversion of convertible preferred stock.

(12) The natural person who has voting and dispositive power for these shares is Jeffrey B. Andreski, Managing Director of Credit Suisse Securities (USA) LLC. Mr. Andreski disclaims beneficial ownership of the shares except for his pecuniary interest. Credit Suisse Securities (USA) LLC is a broker-dealer and,

accordingly, an underwriter. Credit Suisse Securities (USA) LLC has indicated to the issuer that it did not receive the securities as compensation for investment banking services and the securities were acquired in the ordinary course of business, and that at the time of the acquisition of securities, Credit Suisse Securities (USA) LLC had no agreements or understandings, directly or indirectly, with any party to distribute the securities.

(13) Includes 194,256 shares of common stock issuable upon conversion of convertible preferred stock.

(14) Includes 485,630 shares of common stock issuable upon conversion of convertible preferred stock.

* Less than 1%.

We prepared this table based on the information supplied to us by the selling stockholders named in the table, and we have not sought to verify such information.

The selling stockholders listed in the above table may have sold or transferred, in transactions exempt from the registration requirements of the Securities Act, some or all of the shares of our common stock since the date on which the information in the above table was provided to us. Information about the selling stockholders may change over time.

Because the selling stockholders may offer all or some of their shares of our common stock from time to time, we cannot estimate the number of shares of our common stock that will be held by the selling stockholders upon the termination of any particular offering by such selling stockholder. Please refer to Plan of Distribution.

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PLAN OF DISTRIBUTION

We are registering the common stock covered by this prospectus to permit selling stockholders to conduct public secondary trading of these shares from time to time after the date of this prospectus. In connection with our December 2005, November 2006 and March 2007 private placements, we entered into Registration Rights Agreements with the selling stockholders, pursuant to which we agreed to, among other things, bear all expenses, other than brokers or underwriters discounts and commissions, in connection with the registration and sale of the common stock covered by this prospectus. We will not receive any of the proceeds of the sale of the common stock offered by this prospectus. The aggregate proceeds to the selling stockholders from the sale of the common stock will be the purchase price of the common stock less any discounts and commissions. A selling stockholder reserves the right to accept and, together with their agents, to reject, any proposed purchases of common stock to be made directly or through agents.

The common stock offered by this prospectus may be sold from time to time to purchasers:

- directly by the selling stockholders and their successors, which includes their donees, pledgees or transferees or their successors-in-interest, or

- through underwriters, broker-dealers or agents, who may receive compensation in the form of discounts, commissions or agent s commissions from the selling stockholders or the purchasers of the common stock. These discounts, concessions or commissions may be in excess of those customary in the types of transactions involved.

The selling stockholders and any underwriters, broker-dealers or agents who participate in the sale or distribution of the common stock may be deemed to be underwriters within the meaning of the Securities Act. Any selling stockholder that is a registered broker-dealer will be deemed to be an underwriter. As a result, any profits on the sale of the common stock by such selling stockholders and any discounts, commissions or agent s commissions or concessions received by it may be deemed to be underwriting discounts and commissions under the Securities Act. Selling stockholders who are deemed to be underwriters within the meaning of Section 2(11) of the Securities Act will be subject to prospectus delivery requirements of the Securities Act. Underwriters are subject to certain statutory liabilities, including, but not limited to, Sections 11, 12 and 17 of the Securities Act.

The common stock may be sold in one or more transactions at:

- fixed prices;

- prevailing market prices at the time of sale;

- prices related to such prevailing market prices;

- varying prices determined at the time of sale; or

- negotiated prices.

These sales may be effected in one or more transactions:

- on any national securities exchange or quotation on which the common stock may be listed or quoted at the time of the sale;

in the over-the-counter market;

in transactions other than on such exchanges or services or in the over-the-counter market;

through the writing of options (including the issuance by the selling stockholders of derivative securities), whether the options or such other derivative securities are listed on an options exchange or otherwise;

through the settlement of short sales; or

through any combination of the foregoing.

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These transactions may include block transactions or crosses. Crosses are transactions in which the same broker acts as an agent on both sides of the trade.

In connection with the sales of the common stock, the selling stockholders may enter into hedging transactions with broker-dealers or other financial institutions which in turn may:

- engage in short sales of the common stock in the course of hedging their positions;
- sell the common stock short and deliver the common stock to close out short positions;
- loan or pledge the common stock to broker-dealers or other financial institutions that in turn may sell the common stock;
- enter into option or other transactions with broker-dealers or other financial institutions that require the delivery to the broker-dealer or other financial institution of the common stock, which the broker-dealer or other financial institution may resell under the prospectus; or
- enter into transactions in which a broker-dealer makes purchases as a principal for resale for its own account or through other types of transactions.

To our knowledge, there are currently no plans, arrangements or understandings between any selling stockholders and any underwriter, broker-dealer or agent regarding the sale of the common stock by the selling stockholders.

Our common stock is listed on NYSE under the symbol SD.

There can be no assurance that any selling stockholder will sell any or all of the common stock under this prospectus. Further, we cannot assure you that any such selling stockholder will not transfer, devise or gift the common stock by other means not described in this prospectus. In addition, any common stock covered by this prospectus that qualifies for sale under Rule 144 or Rule 144A of the Securities Act may be sold under Rule 144 or Rule 144A rather than under this prospectus. The common stock covered by this prospectus may also be sold to non-U.S. persons outside the U.S. in accordance with Regulation S under the Securities Act rather than under this prospectus. The common stock may be sold in some states only through registered or licensed brokers or dealers. In addition, in some states the common stock may not be sold unless it has been registered or qualified for sale or an exemption from registration or qualification is available and complied with.

The selling stockholders and any other person participating in the sale of the common stock will be subject to the Exchange Act. The Exchange Act rules include, without limitation, Regulation M, which may limit the timing of purchases and sales of any of the common stock by the selling stockholders and any other such person. In addition, Regulation M may restrict the ability of any person engaged in the distribution of the common stock to engage in market-making activities with respect to the particular common stock being distributed. This may affect the marketability of the common stock and the ability of any person or entity to engage in market-making activities with respect to the common stock.

We have agreed to indemnify the selling stockholders against certain liabilities, including liabilities under the Securities Act.

We have agreed to pay substantially all of the expenses incidental to the registration, offering and sale of the common stock to the public, including the payment of federal securities law and state blue sky registration fees, except that we will not bear any underwriting discounts or commissions or transfer taxes relating to the sale of shares of our common stock.

RELATED PARTY TRANSACTIONS

The following is a discussion of transactions between us and our officers, directors and beneficial owners of more than 5% of our common stock. During the fourth quarter of 2007, we adopted a written policy requiring any related party transaction (as defined below) to be reviewed and approved by the disinterested members of our board of directors. 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 (i) 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, (ii) a person known to be the 5% beneficial owner of any class of our voting securities, (iii) 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 (iv) 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 written policy includes factors for disinterested board members to consider in exercising their judgment including terms of the transaction with the related party, availability of comparable products or services from unrelated third parties, terms available from unrelated third parties and the benefits to us.

Well Participation Plan

On June 8, 2006, we adopted the Well Participation Program (the WPP) which permitted Messrs. Ward and Mitchell to participate as working interest owners in the wells that we drill in the future. The WPP was adopted at a time when Mr. Ward proposed to become a significant stockholder of the Company. Our board of directors view was that drilling participation by senior management with significant ownership in us was in our best interest. The payment of proportionate costs of drilling of these wells is similar to a heads up drilling participation that we may, from time to time, enter into with unaffiliated industry participants on specific wells. Mr. Mitchell ceased to participate in the WPP upon his resignation, effective December 31, 2006. On September 21, 2007, Mr. Mitchell agreed to sell us all of his interests under the WPP. Please see Other Transactions with N. Malone Mitchell, 3rd. Mr. Ward remains a participant in the WPP.

Under the WPP, Mr. Ward is permitted to participate in all of the Program Wells, as defined in the WPP, spudded by or on behalf of SandRidge during each calendar year. In order to participate, at least 30 days prior to the beginning of each year, Mr. Ward must provide written notice to the members of the board of directors of his election to participate in the WPP and the percentage working interest which the participant proposes to participate with during the year. Mr. Ward s working interest percentage may not exceed a 3.0% working interest. Mr. Mitchell participated for a 2.0% working interest from June 8, 2006 through December 31, 2006, his effective date of resignation as an officer of SandRidge. Mr. Ward does not participate in any well where our working interest after Mr. Ward s participation would be reduced to below 12.5%. If Mr. Ward fails to provide notice of his election to participate or of the working interest percentage, the amount of the working interest percentage for the relevant calendar year will be deemed to be equal to the working interest percentage for the immediately preceding calendar year. Mr. Ward has participated for a 3.0% working interest in 2006 and elected to a 3.0% working interest for 2007.

The WPP is administered and interpreted by a committee of the board of directors consisting of Messrs. Gilliland and Jordan. Once a compensation committee is established, it will administer and interpret the WPP. In addition, the board of directors, in its sole discretion, may take any action with respect to the WPP that would otherwise be the responsibility of or delegated to the compensation committee. The board of directors has the right to suspend or terminate the WPP after December 31, 2015 by providing written notice of termination to Mr. Ward one year before the effective date of such termination. Mr. Ward s right to participate in the WPP during any calendar year will terminate on the earlier of (1) December 31 of such year; (2) the termination of Mr. Ward s employment by us for cause or death; or (3) the expiration or termination of any and all covenants not to compete subsequent to the termination of Mr. Ward for any reason not included in the foregoing clause (2).

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Mr. Ward s working interest percentage cannot be changed during any calendar year without the prior approval of the compensation committee. Participation by Mr. Ward under the WPP is conditioned on his participation in each Program Well spudded during the calendar year in an amount equal to the greater of the elected working interest percentage or his prior interest in the drilling unit for such Program Well.

The amount paid by Mr. Ward for the acreage assigned in connection with his participation in the WPP is computed as of the first day of each calendar year and is equal to the following amount computed on a per acre basis: (1) all direct third-party costs paid by the Company Entities (as defined in the WPP) and capitalized in the appropriate accounting pool in accordance with our accounting procedures (including capitalized interest, leasehold payments, acquisition costs, landman charges and seismic charges); divided by (2) the acreage in the applicable pool. The acreage charge amount is recomputed by us as of the first day of each calendar year and submitted to the compensation committee for approval. All other costs for Program Wells are billed in accordance with our accounting procedures applicable to third-party participants pursuant to any applicable joint operating agreement or exploration agreement relating to a particular Program Well. Notwithstanding anything to the contrary, in each case the participant s participation in a Program Well will be on no better terms than the terms agreed to by unaffiliated third-party participants in connection with the participation in such Program Well or similar wells operated by the Company Entities.

During 2006, Messrs. Ward and Mitchell were invoiced $1,951,904 and $1,592,136, respectively, for their share of costs for their interests in Program Wells, and received oil and gas revenues from their interests in Program Wells totaling $17,560 and $11,707 respectively. During 2007, Messrs. Ward and Mitchell were invoiced $23,531,380 and $4,154,701, respectively, for their share of costs for their interests Program Wells, and received oil and gas revenues from all of their interests in all Program Wells, including Program Wells drilled in 2006, totaling $2,333,549 and $1,043,420, respectively Mr. Mitchell has sold us all of his interests under the WPP. Please see the Other Transactions with N. Malone Mitchell, 3rd.

Employee Participation Plan

We adopted an Employee Participation Plan in December 2005 that allowed certain employees to participate in the drilling of natural gas and oil wells of our company for up to 5% of our interest in the well. Before that date, a similar plan was informally administered. Our board of directors view was that drilling participation by these key employees was in our best interest. We provided certain employees, including our named executive officers, an allowance to participate in these wells. These allowances were funded by us and treated as compensation. Participating employees were all entitled to invest amounts in addition to the Company funded allocations under the plan. The purpose of the plan was to associate the interest of our employees with the stockholders, maintain competitive compensation levels and provide an incentive for employees to continue employment with us. The plan was terminated effective for all wells drilled on or after May 1, 2006. From January 1, 2006 through the termination of the plan, we awarded $707,000 in allowances under the plan, including $35,000 for each of Mr. Gaines and Ms. Pope and $42,000 for each of Mr. Dutton and Mr. McCann. These allowances were treated as coupons from the Company. Following the termination of the plan, all interests in the plan were assigned to the applicable participant and no further payments were made pursuant to the plan.

No current executive officers of the Company participated in the Employee Participation Plan. During 2006, the following former executive officers were invoiced or assessed compensatory allowances for costs for their interests in the plan wells: Ms. Pope $98,399; Mr. Dutton $83,184; Mr. Gaines $46,902; Mr. McCann $338,635; and each of these former executive officers received oil and gas revenues from their interests in all plan wells, including interests in plan wells drilled in prior years, in the following amounts: Ms. Pope - $65,439; Mr. Dutton $18,491; Mr. Gaines $9,746; Mr. McCann $250,178.

During the first six months of 2007, the following former executive officers were invoiced for costs for their interests in the plan wells: Ms. Pope $11,485; Mr. Dutton $5,351; Mr. Gaines $3,287; Mr. McCann $43,879; and each of these former executive officers received oil and gas revenues from their interests in plan wells, including interests in wells drilled in prior years, in the following amounts: Ms. Pope

$30,826; Mr. Dutton $10,378; Mr. Gaines $6,539; Mr. McCann $152,640. Following their departure from the Company in 2007, the Company purchased the interests in all plan wells from three of the former executive officers in negotiated acquisitions for the following cash payments: Ms. Pope $201,581; Mr. Dutton $75,394; Mr. Gaines - $53,534.

December 2005 Transactions

In December 2005, we entered into the following transactions with related parties as part of an effort to consolidate various interests in energy assets held by management, directors and independent third parties:

- the acquisition of interests in our Piceance Basin acreage, West Texas undeveloped acreage and Larco from Mr. Jordan, a director and our former Vice President, Business, for 1,418,182 shares of common stock valued at $15 per share;

- the acquisition of interests in PetroSource, our Piceance Basin acreage and our Missouri and Nevada projects from Gillco Energy, L.P., an entity controlled by Mr. Gilliland, a director, for 1,406,000 shares of common stock valued at $15 per share; and

- the acquisition of an interest in PetroSource from Mr. McCann, our former Senior Vice President Legal, for $135,000.

The disinterested members of our board of directors reviewed and approved the terms of the transactions with Messrs. Jordan, Gilliland and McCann. Simultaneously with the consummation of these transactions, we purchased other interests in the same assets from independent third parties on substantially similar terms and at substantially similar prices.

Private Placements

Affiliates of Mr. Ward and Mr. Mitchell purchased securities in our November 2006 and March 2007 private placements. Affiliates of Mr. Ward purchased 262,857 shares of our convertible preferred stock in our November 2006 private placement for $210 per share and 3,409,957 shares of common stock in our March 2007 private placement for $18 per share. Affiliates of Mr. Mitchell purchased 47,619 shares of our convertible preferred stock in our November 2006 private placement for $210 per share and 4,548 shares of common stock in connection with a preemptive right in our March 2007 private placement for $18 per share. These purchases were on identical terms and at identical prices as purchases made by independent third parties.

Other Transactions With N. Malone Mitchell, 3rd

Mr. Mitchell, our former Chairman, Chief Executive Officer and President, and his family, on September 30, 2005, traded 2.5% of our then outstanding common stock to us for our 100% interest in Longfellow Ranch Partners, LP (Longfellow). The purpose of this transaction was to separate the Longfellow ranch operations from our ongoing energy operations. While this transaction was approved by our board of directors and a majority of our stockholders, none of our directors at that time were disinterested and Mr. Mitchell controlled a majority of our outstanding common stock. Because of the unique nature of the transaction and the fact that none of our current officers or directors were officers or directors of the company at that time, we are unable to determine whether this transaction was on terms similar to those obtainable from third parties. Longfellow owns surface or minerals or royalty under a significant amount of our exploration and development lands in West Texas, including the WTO. We have natural gas and oil leaseholds that cover all of Longfellow s minerals. Under the leases, we will pay Longfellow royalties, based on production. The lease is for a seven-year primary term, with the option of extending the primary term another three years by paying a market value bonus. The lease royalty is 20% for wells completed before 2009, escalating to maximum of 25% in 2012. At the end of the primary term, the lease will break into approximately 3,000-acre tracts, and each tract will be subject to a 120-day continuous development clause. We also are party to a surface use agreement with Longfellow for use of the surface of the Longfellow Ranch. Under this agreement, we pay Longfellow fees, pursuant to a set schedule, for use of the surface for our natural gas and oil operations and for damages and rights of way. We believe the rates are equivalent to, or less than, the rates paid to other landowners in the area. As described below, this agreement was amended and restated on September 21, 2007. For 2003, 2004 and the nine months ended September 30, 2005, when operations were discontinued income (loss) from Longfellow s operations were ($128,000), $683,000 and $638,000, respectively. These numbers included, among other things, royalties, damages and agricultural operations on the lands, minerals and royalties now indirectly owned by the Mitchell family. For the last three months of 2005, the year ended 2006, and the six months ended June 30, 2007, we paid Longfellow $1,019,710, $4,156,082 and $1,458,958, respectively.

On November 29, 2007, pursuant to a letter agreement with Mr. Mitchell, Longfellow and certain of his affiliates, we purchased certain natural gas and oil working interests from Mr. Mitchell for a cash purchase price of $32 million. These natural gas and oil interests included the interests located on the West Ranch, a ranch adjacent to Longfellow Ranch recently acquired by Mr. Mitchell. The natural gas and oil interests also included all other working interests of Mr. Mitchell and his affiliates in wells and leasehold acreage owned or operated by us or our affiliates, including interests owned through our Well Participation Program. For the years 2004, 2005, 2006 and the six months ended June 30, 2007, we paid Mr. Mitchell $147,000, $170,963, $140,538 and $18,183, respectively, in connection with his ownership interest in these assets. In connection with the letter agreement, we also entered in to an amended and restated surface use and rights agreement regarding our access and use of the surface of lands owned by Mr. Mitchell in connection with our natural gas and oil interests on such lands.

The disinterested members of our board of directors determined that the transactions contemplated by the letter agreement, including the amended and restated surface use agreement, are on terms not materially less favorable than those that might reasonably have been obtained in a comparable transaction on an arms-length basis from a party that is not our affiliate and are fair to us from a financial point of view. Simultaneously with the execution of the letter agreement, Mr. Mitchell resigned as a director.

In August 2006, Mr. Mitchell acquired our interest in entities which owned Stockton Plaza, a commercial shopping center located in Fort Stockton, Texas, a restaurant franchise, and other non-core assets and investments, for an aggregate purchase price of $6,128,899. This transaction was determined to be in our best interests by the disinterested members of our board of directors and we believe it to be on terms similar to those available from unaffiliated third parties.

On May 2, 2007, we acquired oil and gas leaseholds on mineral interests held by the State of Texas underlying surface properties owned by Longfellow. Under Texas law, Longfellow executed these leases as agent for the State of Texas and is entitled to receive one-half of the payments made to the lessor under the leases. As a result, we paid Longfellow $8.3 million for its share of lease bonus payments. The terms of these lease transactions were similar to other State of Texas lease transactions that we negotiated in the ordinary course of our business with third party surface owners for nearby leaseholds. Our senior officers negotiated the terms of the lease transactions at arms length with Mr. Mitchell, acting as an officer of Longfellow in its capacity as agent for the State of Texas, and the transactions were approved by the disinterested members of our board of directors.

Other Transactions With Dan Jordan

Mr. Jordan, a director and our former Vice President, Business, has participated in projects since 2000. In March 2006, we acquired Mr. Jordan s 12.5% interest in PetroSource for $5,489,401. In July 2006 we acquired Mr. Jordan s interests in our producing natural gas and oil properties for $9,000,000. For the years 2004, 2005, 2006 and the six months ended June 30, 2007, we recognized the capital contributions from Mr. Jordan related to our drilling projects of $4,274,000, $5,670,081, $2,397,188 and $324,950, respectively. For the same periods, we paid Mr. Jordan $1,532,000, $2,113,020, $1,496,598 and $6,156, respectively. From August 2002 until October 2005, he received consulting fees from Larco of $40,000 per month. In June 2007, we purchased all of the interests in twelve producing wells and one well being drilled, which interests were owned by Wallace Jordan, LLC, a limited liability company a majority interest in is owned and controlled by Mr. Jordan (Wallace Jordan). In addition and as a part of this same transaction, we purchased the interest owned by Wallace Jordan in the Sabino pipeline and the West Piñon Gathering System and certain oil and gas leases covering lands in Pecos County, Texas, as well as the interest owned by Mr. Jordan individually in Integra Energy. The purchase price for these assets was $3.3 million plus the reimbursement of approximately

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$236,000 of costs attributable to Wallace Jordan s 10% working interest in one of our wells. Each of the transactions with Mr. Jordan was determined to be in our best interests by the disinterested members of our board of directors. We believe the terms of these transactions were similar to those that could have been obtained from an unrelated third party.

Other Transactions With Bill Gilliland

Mr. Gilliland has served as a director since January 2006. In 2003, Mr. Gilliland assisted us in the acquisition of the PetroSource assets and acquired an approximate 18.8% interest in PetroSource through Gillco Energy, L.P. Through that same entity, he also participated in our Piceance Basin acreage, and various drilling projects in Missouri and Nevada. As described above under December 2005 Transactions, we acquired these interests in December 2005. In February 2006, we acquired an office building in Midland, Texas from a partnership affiliated with Mr. Gilliland for $950,000. This transaction was determined to be in our best interests by the disinterested members of our board of directors. We believe the terms of this transaction were similar to those that could have been obtained from an unrelated third party.

Transaction With Roy Oliver

In September 2006, we entered into a new facilities lease with a director, Mr. Oliver. The lease extends to August 2009 with annual future rental payments of $1.1 million in 2007 and 2008 and $0.7 million in 2009. The terms of the lease were received and approved by our board of directors and we believe that the rent expense it must pay under this lease is at fair market rates. Rent expense in 2006 related to this facilities lease was $0.3 million.

DESCRIPTION OF CAPITAL STOCK

Our authorized capital stock consists of 400,000,000 shares of common stock, par value $0.001 per share, and 50,000,000 shares of preferred stock, no par value. As of November 30, 2007, we had 141,845,661 outstanding shares of common stock and 2,184,286 shares of convertible preferred stock outstanding. We have no outstanding options to purchase common stock, however, we have granted restricted stock awards for approximately 1.6 million shares (other than shares cancelled or forfeited).

Common Stock

Subject to any special voting rights of any series of preferred stock that we may issue in the future, each share of common stock has one vote on all matters voted on by our stockholders, including the election of our directors. Because holders of common stock do not have cumulative voting rights, the holders of a majority of the shares of common stock can elect all of the members of the board of directors standing for election, subject to the rights, powers and preferences of any outstanding series of preferred stock.

No share of common stock affords any preemptive rights or is convertible, redeemable, assessable or entitled to the benefits of any sinking or repurchase fund. Holders of common stock will be entitled to dividends in the amounts and at the times declared by our board of directors in its discretion out of funds legally available for the payment of dividends.

Holders of common stock will share equally in our assets on liquidation after payment or provision for all liabilities and any preferential liquidation rights of any preferred stock then outstanding. All outstanding shares of common stock are fully paid and non-assessable.

Preferred Stock

Convertible Preferred Stock

Dividends. Each holder of our convertible preferred stock is entitled to receive a quarterly cash dividend at an annual rate of 7.75% of the accreted value of each share of convertible preferred stock held by such holder. The accreted value is currently $210 per share. In lieu of making any such quarterly cash dividend, we may, at our option, increase the accreted value of each share of convertible preferred stock by 2.3125% of the existing accreted value. We are prohibited from paying any cash dividends on any capital stock junior or equal in rank to our convertible preferred stock, including our common stock, without the consent of holders of a majority of our outstanding convertible preferred stock. In addition, each holder is entitled to any dividend or distribution made with respect to our common stock as if such holder had converted its shares of convertible preferred stock to common stock on the record date.

Voting. Each holder of our convertible preferred stock is entitled to vote with the holders of our common stock on all matters submitted to a vote of stockholders as if such holder had converted its shares of convertible preferred stock to common stock on the record date for such vote. In addition, certain actions, including the issuance of any capital stock senior or equal in rank to our convertible preferred stock, any amendment to our Certificate of Incorporation and certain other fundamental transactions, shall require the approval of the holders of a majority of our convertible preferred stock.

Liquidation. In the event of any voluntary or involuntary liquidation, dissolution or winding-up of SandRidge, subject to the payments of any debts or other liabilities of SandRidge and prior to any payment to the holders of our common stock, each holder of our convertible preferred stock shall receive with respect to each share an amount equal to the greater of (i) the accreted value as of the date of the liquidation and (ii) the amount that such holder would have received had it converted its shares of convertible preferred stock on the date of such liquidation, dissolution or winding-up.

Conversion at the Option of the Holders. Each holder of our convertible preferred stock may convert any or all of its shares into common stock at any time. The shares of convertible preferred stock shall be converted into a number of shares of common stock equal to the product of the number of shares of convertible preferred stock being converted multiplied by the quotient of (i) the accreted value and (ii) the conversion price. The conversion price is currently $20.59 per share.

Issuances of common stock following our initial public offering will not result in any adjustment to the conversion price.

Conversion at the Option of SandRidge. At any time after May 7, 2008, if the conditions described below have been satisfied, we may, at our option, cause all the shares of convertible preferred stock to be converted into a number of shares of common stock equal to the number of shares of convertible preferred stock multiplied by the quotient of (i) the accreted value and (ii) the conversion price then in effect. We may not effect such a conversion unless the following conditions have been satisfied:

- we have completed our initial public offering or an offering of similar size and price;

- this shelf registration statement shall be effective;

- our common stock is listed on a national exchange and the closing price exceeds 100% of the conversion price for at least 20 trading days in any 30 consecutive trading day period; and

- certain other conditions, including no event of default.

In connection with any conversion by us, unless the closing price of our common stock exceeds 150% of the conversion price for at least 20 trading days in any 30 consecutive trading day period, we must also make a payment to each holder of shares of convertible preferred stock equal to (i) the accreted value, multiplied by (ii) 0.155.

Warrant to Purchase Convertible Preferred Stock

We have issued warrants to purchase 482,381 shares of our convertible preferred stock. Generally, the warrant entitles the warrantholder to exercise the warrant by tendering a certain number of shares of common stock purchased in connection with the warrant for a number of shares of convertible preferred stock with an aggregate accreted value at the time of exercise equal the number of shares of common stock tendered as exercise consideration multiplied by $19. The accreted value of a share of convertible preferred stock is subject to increase in the event of non-payment of preferred stock dividends in cash, in which event the number of shares of convertible preferred stock that may be issued upon exercise of the Warrant and tender of common stock will be reduced.

The warrant may be exercised in whole or in part (through the tender of whole shares of common stock) commencing on the date of issue and ending at 5:00 p.m., New York time, on the earlier of (i) May 15, 2013 and (ii) the first day in which all outstanding shares of convertible preferred stock have been fully redeemed or converted (voluntarily or involuntarily) pursuant to the Certificate of Designations of the convertible preferred stock. Holders of warrants are entitled to all notices delivered to holders of convertible preferred stock and certain other notices as set forth in the warrant.

Additional Preferred Stock

Our board of directors may, without any action by holders of the common stock:

- adopt resolutions to issue preferred stock in one or more classes or series;

- fix or change the number of shares constituting any class or series of preferred stock; and establish or change the rights of the holders of any class or series of preferred stock.

The rights of any class or series of preferred stock may include, among others:

general or special voting rights;

preferential liquidation or preemptive rights;

preferential cumulative or noncumulative dividend rights;

redemption or put rights; and

conversion or exchange rights.

We may issue shares of, or rights to purchase, preferred stock the terms of which might:

adversely affect voting or other rights evidenced by, or amounts otherwise payable with respect to, the common stock;

discourage an unsolicited proposal to acquire us; or

facilitate a particular business combination involving us.

Any of these actions could discourage a transaction that some or a majority of our stockholders might believe to be in their best interests or in which our stockholders might receive a premium for their stock over its then market price.

Amended and Restated Shareholders Agreement

In connection with the closing of the NEG acquisition, we entered into a Shareholders Agreement with certain of our stockholders, including Mr. Ward, our Chairman, Chief Executive Officer and President, Mr. Mitchell, a director, and affiliates of AREP. The Shareholders Agreement was subsequently amended and restated in connection with the sale of the shares held by AREP to other stockholders (the New Investors). The Amended and Restated Shareholders Agreement contains certain restrictions on transfer, tagalong rights, a selected preemptive right and registration rights, each of which is described more fully below.

Transfer Restrictions. The Amended and Restated Shareholders Agreement prohibits the parties from transferring any of their securities prior to 180 days following the consummation of a qualified public offering, other than to family members and affiliates other than SandRidge or pursuant to the tagalong provisions described below. However, the Amended and Restated Shareholders Agreement allows Messrs. Ward and Mitchell to pledge their shares subject to certain conditions, in connection with a bona fide loan. The New Investors may also transfer their securities on the PORTAL market or pursuant to an exemption under the securities laws. Qualified public offering is defined as an underwritten, broad based public offering in excess of $100 million of common stock (which results in gross proceeds to the sellers of at least $100 million) and results in not less than 20 million shares of common stock (including common stock covered by any registration rights agreement and any shares sold pursuant to any previous public offerings) being listed for trading on a national securities exchange (including Nasdaq). Our proposed initial public offering was a qualified public offering for the purposes of the Amended and Restated Shareholders Agreement.

Tag-Along Rights. If Messrs. Ward or Mitchell propose to sell shares of our common stock (other than to family members and affiliates other than SandRidge) prior to a qualified public offering, the New Investors have the right to elect to sell all of their shares of our common stock on the same terms. Following a qualified public offering, if Messrs. Ward or Mitchell propose to sell shares of our common stock in excess of 3% of our outstanding common stock on a fully diluted basis (other than to family members and affiliates other than SandRidge to Rule 144 or in a registered offering other than a block trade), the New Investors have the right to elect to sell their proportionate number of shares of our common stock on the same terms. The tagalong rights expire on the earlier of (i) the date upon which the New Investors cease to own at least 20% of our shares of common stock on purchased from affiliates of AREP and (ii) two years following a qualified public offering.

Registration Rights. The Amended and Restated Shareholders Agreement provides each of Mr. Ward, Mr. Mitchell and the affiliates of AREP certain registration rights. For a description of these rights, please read Registration Rights Amended and Restated Shareholders Agreement.

Ares Shareholder Agreement

In connection with our March 2007 private placement, we entered into a Shareholders Agreement (the Ares Shareholders Agreement) with certain affiliates of Ares Management LLC (Ares) and Mr. Ward. The Ares Shareholder Agreement contains tag-along rights and a voting requirement, each of which is described more fully below.

Tag-Along Rights. If Mr. Ward proposes to sell shares of common stock (other than to family members and affiliates other than SandRidge), he has agreed to use his commercially reasonable efforts to structure such sale in a manner as to allow Ares to sell the same proportionate amount of its shares on the same terms. To the extent Ares is unable to sell its proportionate amount of shares as a result of other tag-along rights, Mr. Ward shall decrease the amount of shares he is selling to allow for Ares to sell the same proportionate amount of its shares as Mr. Ward. The tag-along rights expire two years following the completion of this offering.

Voting Agreement. We have agreed, upon the request of Ares, to include its designee for director to be placed on the ballot for election at our 2008 annual meeting. In addition, Mr. Ward has agreed to vote his shares in favor of such designee at our 2008 annual meeting.

Registration Rights

Amended and Restated Shareholders Agreement. Pursuant to a Amended and Restated Shareholders Agreement among us and certain of our stockholders, including Messrs. Ward and Mitchell and certain of their respective affiliates, we have agreed to allow such parties to offer their shares of our common stock in certain future registered offerings of our common stock, subject to our priority and customary limitations. We have also agreed to use our reasonable best efforts to cause a shelf registration statement to become effective with respect to the securities held by the stockholders party to the Amended and Restated Shareholders Agreement upon their request. Such request may not be made within 120 days of the effectiveness of a registration statement requested pursuant to the Amended and Restated Shareholders Agreement or that such stockholders are entitled to participate in pursuant to the Amended and Restated Shareholders Agreement. In addition, the stockholders party to the agreement (other than Messrs. Ward and Mitchell and their affiliates) may not request that we file a shelf registration statement prior to the date which is 201 days following the consummation of our initial public offering. The stockholders party to the agreement (other than Messrs. Ward and Mitchell and their affiliates) may transfer their registration rights under this agreement in connection with sales in excess of 2,000,000 shares of our common stock. Each of the parties to the Amended and Restated Shareholders Agreement have agreed not to effect any sale or distribution of our common stock or securities convertible or exchangeable or exercisable for our common stock for a period of 180 days from the date of our initial public offering.

Anti-Takeover Provisions of Delaware Law, Our Certificate of Incorporation and Bylaws

Written Consent of Stockholders

Our certificate of incorporation and bylaws provide that any action required or permitted to be taken by our stockholders must be taken at a duly called meeting of stockholders and not by written consent.

Amendment of the Bylaws

Under Delaware law, the power to adopt, amend or repeal bylaws is conferred upon the stockholders. A corporation may, however, in its certificate of incorporation also confer upon the board of directors the power to adopt, amend or repeal its bylaws. Our charter and bylaws grant our board the power to adopt, amend and repeal our bylaws on the affirmative vote of a majority of the directors then in office. Our stockholders may adopt, amend or repeal our bylaws but only at any regular or special meeting of stockholders by the holders of not less than 662/3% of the voting power of all outstanding voting stock.

Special Meetings of Stockholders

Our bylaws preclude the ability of our stockholders to call special meetings of stockholders.

Other Limitations on Stockholder Actions

Advance notice is required for stockholders to nominate directors or to submit proposals for consideration at meetings of stockholders. In addition, the ability of our stockholders to remove directors without cause is precluded.

Classified Board

Only one of three classes of directors is elected each year. See Management Board of Directors.

Limitation of Liability of Officers and Directors

Our certificate of incorporation provides that no director shall be personally liable to us or our stockholders for monetary damages for breach of fiduciary duty as a director, except for liability as follows:

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

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

for unlawful payment of a dividend or unlawful stock purchase or stock redemption; and

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

The effect of these provisions is to eliminate our rights and our stockholders rights, through stockholders derivative suits on our behalf, to recover monetary damages against a director for a breach of fiduciary duty as a director, including breaches resulting from grossly negligent behavior, except in the situations described above.

Business Combination Under Delaware Law

We are subject to the provisions of Section 203 of the Delaware General Corporation Law. In general, Section 203 prohibits a publicly held Delaware corporation from engaging in a business combination with an interested stockholder for a period of three years after the date of the transaction in which the person became an interested stockholder, unless the business combination is approved in a prescribed manner.

Section 203 defines a business combination as a merger, asset sale or other transaction resulting in a financial benefit to the interested stockholders. Section 203 defines an interested stockholder as a person who, together with affiliates and associates, owns, or, in some cases, within three years prior, did own, 15% or more of the corporation s voting stock. Under Section 203, a business combination between us and an interested stockholder is prohibited unless:

our board of directors approved either the business combination or the transaction that resulted in the stockholders becoming an interested stockholder prior to the date the person attained the status;

upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of our voting stock outstanding at the time the transaction commenced, excluding, for purposes of determining the number of shares outstanding, shares owned by persons who are directors and also officers and issued employee stock plans, under which employee participants do not have the right to determine confidentially whether shares held under the plan will be tendered in a tender or exchange offer; or

the business combination is approved by our board of directors on or subsequent to the date the person became an interested stockholder and authorized at an annual or special meeting of the stockholders by the affirmative vote of the holders of at least 662/3% of the outstanding voting stock that is not owned by the interested stockholder.

This provision has an anti-takeover effect with respect to transactions not approved in advance by our board of directors, including discouraging takeover attempts that might result in a premium over the market price for the shares of our common stock. With approval of our stockholders, we could amend our certificate of incorporation in the future to elect not to be governed by the anti-takeover law. This election would become effective twelve months after the adoption of the amendment and would not apply to any business combination with any person who became an interested stockholder on or before the adoption of the amendment.

CERTAIN U.S. TAX CONSEQUENCES TO NON-U.S. HOLDERS

The following is a general discussion of the principal U.S. federal income and estate tax consequences of the ownership and disposition of our common stock by a non-U.S. holder. As used in this discussion, the term non-U.S. holder means a beneficial owner of our common stock that is not, for U.S. federal income tax purposes:

- an individual who is a citizen or resident of the United States;
- a corporation or partnership (including any entity treated as a corporation or partnership for U.S. federal income tax purposes) created or organized in or under the laws of the United States, or of any political subdivision of the United States (unless, in the case of a partnership, U.S. Treasury Regulations are adopted which provide otherwise);
- an estate whose income is subject to U.S. federal income taxation regardless of its source; or
- a trust, if a U.S. court is able to exercise primary supervision over the administration of the trust and one or more United States persons have the authority to control all substantial decisions of the trust, or if it has a valid election in effect under applicable U.S. Treasury Regulations to be treated as a United States person.

In any calendar year, an individual may be treated for U.S. federal income tax purposes as a resident of the United States by, among other ways, being present in the United States for at least 31 days in that calendar year and for an aggregate of at least 183 days during a three-year period ending in the current calendar year. For purposes of the 183-day calculation, all of the days on which such individual was present in the current year, one-third of the days in the immediately preceding year and one-sixth of the days in the second preceding year are counted. Residents are taxed for U.S. federal income tax purposes as if they were U.S. citizens. This discussion does not consider:

- U.S. state or local or non-U.S. tax consequences;
- all aspects of U.S. federal income and estate taxes or specific facts and circumstances that may be relevant to a particular non-U.S. holder s tax position, including, in the case of a non-U.S. holder that is an entity treated as a partnership for U.S. federal income tax purposes, the fact that the U.S. tax consequences of holding and disposing of our common stock may be affected by certain determinations made at the partner level;
- the tax consequences for the stockholders, partners or beneficiaries of a non-U.S. holder;
- special tax rules that may apply to particular non-U.S. holders, such as financial institutions, insurance companies, tax-exempt organizations, U.S. expatriates, broker-dealers, and traders in securities; or
- special tax rules that may apply to a non-U.S. holder that holds our common stock as part of a straddle, hedge, conversion transaction, synthetic security or other integrated investment.

The following discussion is based on provisions of the U.S. Internal Revenue Code of 1986, as amended (the Code), existing and proposed U.S. Treasury Regulations and administrative and judicial interpretations, all as of the date of this prospectus, and all of which are subject to change, retroactively or prospectively. The following summary assumes that a non-U.S. holder holds our common stock as a capital asset. **Each non-U.S. holder should consult a tax advisor regarding the U.S. federal, state, local and non-U.S. income and other tax consequences of acquiring, holding and disposing of shares of our common stock.**

Distributions on Common Stock

We do not expect to pay any cash distributions on our common stock in the foreseeable future; however, in the event that we do make such cash distributions, these distributions generally will constitute dividends for U.S. federal income tax purposes to the extent paid from our current or accumulated earnings and profits, as determined under U.S. federal income tax principles. Any amount paid in excess of such earnings and profits generally will be treated as a recovery of tax basis, to the extent thereof, and then gain from sale. Distributions paid to non-U.S. holders of our common stock that are not effectively connected with the non-U.S. holder s conduct of a U.S. trade or business generally will be subject to U.S. withholding tax at a 30% rate, or if a tax treaty applies, a lower rate specified by the treaty.

A non-U.S. holder that claims the benefit of an applicable income tax treaty generally will be required to provide an Internal Revenue Service Form W-8 BEN and meet certain other requirements. However,

- in the case of common stock held by a foreign partnership, the certification requirement will generally be applied to the partners of the partnership and the partnership will be required to provide certain information;
- in the case of common stock held by a foreign trust, the certification requirement will generally be applied to the trust or the beneficial owners of the trust depending on whether the trust is a foreign complex trust, foreign simple trust or foreign grantor trust as defined in the U.S. Treasury Regulations; and
- look-through rules will apply for tiered partnerships, foreign simple trusts and foreign grantor trusts.

A non-U.S. holder that is a foreign partnership or a foreign trust is urged to consult its own tax advisor regarding its status under these U.S. Treasury Regulations and the certification requirements applicable to it.

A non-U.S. holder that is eligible for a reduced rate of U.S. federal withholding tax under an income tax treaty may obtain a refund or credit of any excess amounts withheld by filing an appropriate claim for refund with the U.S. Internal Revenue Service. Non-U.S. holders should consult their tax advisors regarding their entitlement to benefits under a relevant income tax treaty.

Dividends that are effectively connected with a non-U.S. holder s conduct of a trade or business in the United States and, if an income tax treaty applies, are attributable to a permanent establishment in the United States, are taxed on a net income basis at the regular graduated rates and in the manner applicable to United States persons. In that case, we will not withhold U.S. federal withholding tax if the non-U.S. holder complies with applicable certification and disclosure requirements (including providing Internal Revenue Service Form W-8 ECI). In addition, a branch profits tax may be imposed at a 30% rate, or a lower rate under an applicable income tax treaty, on dividends received by a foreign corporation that are effectively connected with its conduct of a trade or business in the United States.

Disposition of Common Stock

We believe that we are a United States real property holding corporation. Generally, a corporation is a United States real property holding corporation if the fair market value of its United States real property interests equals or exceeds 50% of the sum of the fair market value of its worldwide real property interests and its other assets used or held for use in a trade or business. Notwithstanding our status as a United States real property holding corporation, a non-U.S. holder of our common stock generally will not be subject to U.S. federal income tax on gain recognized on a disposition of our common stock unless:

- the gain is effectively connected with the non-U.S. holder s conduct of a trade or business in the United States and, if an income tax treaty applies, is attributable to a permanent establishment maintained by the non-U.S. holder in the United States; in these cases, the gain will be taxed on a net income basis at the rates and in the manner applicable to United States persons, and if the non-U.S. holder is a foreign corporation, the branch profits tax described above may also apply;
- the non-U.S. holder is an individual who is present in the United States for 183 days or more in the taxable year of the disposition and meets other requirements; or

the non-U.S. holder actually or constructively owns more than five percent of our common stock at any time during the shorter of the five-year period ending on the date of disposition or the period that the non-U.S. holder held our common stock, provided that our common stock is regularly traded on an established securities market, within the meaning of Section 897 of the Code and applicable Treasury Regulations, during the calendar year in which the sale or other disposition occurs.

Non-United States holders should consult their own tax advisors with respect to the application of the foregoing rules.

U.S. Federal Estate Tax

Common stock owned or treated as owned by an individual who is a non-U.S. holder for U.S. federal estate tax purposes at the time of death will be included in the individual s gross estate for U.S. federal estate tax purposes, unless an applicable estate tax or other treaty provides otherwise, and therefore may be subject to U.S. federal estate tax.

Information Reporting and Backup Withholding Tax

Generally, we must report annually to any non-U.S. holder and the U.S. Internal Revenue Service the amount of any dividends paid to such holder, the holder s name and address, and the amount, if any, of tax withheld. Copies of the information returns reporting those dividends and amounts withheld also may be made available to the tax authorities in the country in which the non-U.S. holder resides under the provisions of any applicable tax treaty or exchange of information agreement.

In addition to information reporting requirements, dividends paid to a non-U.S. holder may be subject to U.S. backup withholding tax. A non-U.S. holder generally will be exempt from this backup withholding tax, however, if such holder properly provides a Form W-8BEN certifying that such holder is a non-United States person or otherwise establishes an exemption and we do not know or have reason to know that the holder is a United States person.

The gross proceeds from the disposition of our common stock may be subject to information reporting and backup withholding. If a non-U.S. holder sells shares of our common stock outside the United States through a non-U.S. office of a non-U.S. broker and the sales proceeds are paid to such holder outside the United States, then the U.S. backup withholding and information reporting requirements generally will not apply to that payment. However, U.S. information reporting, but not backup withholding, generally will apply to a payment of sales proceeds, even if that payment is made outside the United States, if the non-U.S. holder sells shares of our common stock through a non-U.S. office of a broker that:

- is a United States person;
- derives 50% or more of its gross income in specific periods from the conduct of a trade or business in the United States;
- is a controlled foreign corporation for U.S. federal tax purposes; or
- is a foreign partnership, if at any time during its tax year:
  - one or more of its partners are United States persons who in the aggregate hold more than 50% of the income or capital interests in the partnership; or
  - the foreign partnership is engaged in a U.S. trade or business,

unless the broker has documentary evidence in its files that the holder is not a U.S. person and certain other conditions are met, or the holder otherwise establishes an exemption.

If a non-U.S. holder receives payments of the proceeds of a sale of our common stock to or through a U.S. office of a broker, the payment will be subject to both U.S. backup withholding and information reporting unless such holder properly provides a Form W-8BEN certifying that such holder is not a United States person or otherwise establishes an exemption, and we do not know or have reason to know that such holder is a United States person.

A non-U.S. holder generally may obtain a refund of any amounts withheld under the backup withholding rules that exceed such holder s U.S. federal income tax liability by timely filing a properly completed claim for refund with the U.S. Internal Revenue Service.

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LEGAL MATTERS

The validity of the shares offered hereby will be passed upon for us by Vinson & Elkins L.L.P.

EXPERTS

The financial statements of SandRidge Energy, Inc. 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 have been so included in reliance on the report of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

The combined financial statements of NEG Oil & Gas LLC and subsidiaries, excluding National Energy Group, Inc. and the 103/4% Senior Notes due from National Energy Group Inc., but including National Energy Group Inc.   s 50% membership interest in NEG Holding LLC as of December 31, 2004 and 2005 and for each of the three years in the period ended December 31, 2005 included in this prospectus and elsewhere in the registration statement have been audited by Grant Thornton LLP, independent registered public accounting firm, as indicated in their report with respect thereto, and is included herein in reliance upon the authority of said firm as experts in giving said report.

The estimated reserve evaluations and related calculations for our WTO properties as of December 31, 2005 and PetroSource properties as of December 31, 2005 and 2006 and June 30, 2007 have been included in this prospectus in reliance upon the report of DeGolyer and MacNaughton, independent petroleum engineering consultants, given upon their authority as experts in petroleum engineering. The estimated reserve evaluations and related calculations for our Piceance Basin properties as of December 31, 2005 and our WTO, East Texas, Gulf of Mexico, Gulf Coast and certain other properties as of December 31, 2006 and June 30, 2007 have been included in this prospectus in reliance upon the report of Netherland, Sewell & Associates, Inc., independent petroleum engineering consultants, given upon their authority as experts in petroleum engineering. The estimated reserve evaluations for certain of our other properties as of December 31, 2005 have been included in this report in reliance upon the report of Harper & Associates, Inc., independent petroleum engineering consultants, given upon their authority as experts in petroleum engineering.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC a registration statement on Form S-1 under the Securities Act with respect to the common stock being sold in this offering. This prospectus, which forms part of the registration statement, does not contain all of the information set forth in the registration statement and the exhibits and schedules to the registration statement. For further information with respect to us and our common stock being sold in this offering, we refer you to the registration statement and the exhibits and schedules filed as a part of the registration statement. Statements contained in this prospectus concerning the contents of any contract or any other document are not necessarily complete. If a contract or document has been filed as an exhibit to the registration statement, we refer you to the copy of the contract or document that has been filed as an exhibit and is qualified in all respects by the filed exhibit. The registration statement, including exhibits and schedules filed, may be inspected without charge at the Public Reference Room of the SEC at 100 F Street, NE, Washington, D.C. 20549, and copies of all or any part of it may be obtained from that office after payment of fees prescribed by the SEC. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC maintains a website that contains reports, proxy and information statements and other information regarding registrants that file electronically with the SEC at http://www.sec.gov. The other information we file with the SEC is not part of the registration statement of which this prospectus forms a part.

We file annual, quarterly and current reports, proxy statements and other information with the SEC. These filings are available on our website at http://www.sandridgeenergy.com. Information on, or accessible through, this website is not a part of, and is not incorporated into, this prospectus. In addition, we will provide copies of our filings free of charge to our stockholders upon request.

FINANCIAL STATEMENTS

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Report of Independent Registered Public Accounting Firm

To the Board of Directors
and Stockholders of SandRidge Energy, Inc.

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, changes in stockholders equity and of cash flows present fairly, in all material respects, the financial position of SandRidge Energy, Inc. and its subsidiaries at December 31, 2005 and 2006, and the results of their operations and their cash flows for each of the three years then ended in conformity with accounting principles generally accepted in the United States of America. 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 of these statements in accordance with standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the financial statements, the Company changed the manner in which it accounts for oil and gas operations from the successful efforts method to the full cost method in 2006, and accordingly, the financial statements have been retroactively restated. Also, as discussed in Note 1, the 2006 consolidated financial statements have been restated to correct the fair value of derivative contracts.

PricewaterhouseCoopers LLP

Houston, Texas
March 30, 2007, except for Restatement section of Note 1 to the consolidated financial statements, as to which the date is May 11, 2007.

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SandRidge Energy, Inc. and Subsidiaries

Consolidated Balance Sheets

	As of December 31, 2005 (Restated)	As of December 31, 2006 (Restated)
	(In thousands except per share amount)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 45,731	$ 38,948
Restricted cash	2,373	
Accounts receivable, net:		
Trade	59,180	89,774
Related parties	5,376	5,731
Inventories	1,606	2,544
Deferred income taxes	1,323	6,315
Other current assets	3,244	31,494
Total current assets	118,833	174,806
Oil and natural gas properties, using full cost method of accounting		
Proved	160,789	1,636,832
Unproved	33,974	282,374
Less: accumulated depreciation and depletion	(35,029)	(60,752)
	159,734	1,858,454
Other property, plant and equipment, net	178,147	276,264
Goodwill		26,198
Investments	1,614	3,584
Restricted deposits		33,189
Other assets	355	15,889
Total assets	$ 458,683	$ 2,388,384
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Current maturities of long-term debt	$ 12,997	$ 26,201
Accounts payable and accrued expenses:		
Trade	95,435	129,799
Related parties	78	1,834
Derivative contracts	2,132	958

Total current liabilities	110,642	158,792
Long-term debt	30,136	1,040,630
Derivative contracts		3,052
Other long-term obligations		21,219
Asset retirement obligation	6,979	45,216
Deferred income taxes	13,747	24,922
Total liabilities	161,504	1,293,831
Commitments and contingencies (Note 16)		
Minority interest	8,177	5,092
Redeemable convertible preferred stock, $0.001 par value, 2,650 shares authorized, 2,137 shares issued and outstanding at December 31, 2006		439,643
Stockholders equity:		
Preferred stock, no par; 50,000 shares authorized; no shares issued and outstanding in 2005 and 2006		
Common stock, $0.001 par value, 400,000 shares authorized; 74,332 issued and 72,917 outstanding at 2005 and 93,048 issued and 91,604 outstanding at 2006	73	92
Additional paid-in capital	243,920	574,868
Deferred compensation	(14,885)	
Treasury stock, at cost	(17,335)	(17,835)
Retained earnings	77,229	92,693
Total stockholders equity	289,002	649,818
Total liabilities and stockholders equity	$ 458,683	$ 2,388,384

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

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SandRidge Energy, Inc. and Subsidiaries

Consolidated Statements of Operations

	Years Ended December 31,		
	2004 (Restated)	2005 (Restated)	2006 (Restated)
	(In thousands except per share amounts)		
Revenues:			
Natural gas and crude oil	$ 33,685	$ 49,987	$ 101,252
Drilling and services	39,417	80,343	139,049
Midstream and marketing	98,906	147,133	122,896
Other	3,987	10,230	25,045
Total revenues	175,995	287,693	388,242
Expenses:			
Production	10,230	16,195	35,149
Production taxes	2,497	3,158	4,654
Drilling and services	26,442	52,122	98,436
Midstream and marketing	96,180	141,372	115,076
Depreciation, depletion and amortization natural gas and crude oil	4,909	9,313	26,321
Depreciation, depletion and amortization other	7,765	14,893	29,305
General and administrative	6,554	11,908	55,634
Loss (gain) on derivative contracts	878	4,132	(12,291)
Loss (gain) on sale of assets	(210)	547	(1,023)
Total expenses	155,245	253,640	351,261
Income from operations	20,750	34,053	36,981
Other income (expense):			
Interest income	56	206	1,109
Interest expense	(1,678)	(5,277)	(16,904)
Minority interest	(262)	(737)	(296)
Income (loss) from equity investments	(36)	(384)	967
Total other income (expense)	(1,920)	(6,192)	(15,124)
Income before income tax expense	18,830	27,861	21,857
Income tax expense	6,433	9,968	6,236
Income from continuing operations	12,397	17,893	15,621
Income from discontinued operations (net of tax expense of $232 and $118 in 2004 and 2005, respectively)	451	229	

Income before extraordinary gain	12,848	18,122	15,621
Extraordinary gain on Foreland acquisition	12,544		
Net income	25,392	18,122	15,621
Preferred stock dividends and accretion			3,967
Income available to common stockholders	$ 25,392	$ 18,122	$ 11,654
Basic and Diluted Earnings Per Share:			
Income from continuing operations	$ 0.22	$ 0.31	$ 0.21
Income from discontinued operations, net of income tax	0.01	0.01	
Extraordinary gain on Foreland acquisition	0.22		
Preferred dividends			(0.05)
Basic and diluted income per share available to common stockholders	$ 0.45	$ 0.32	$ 0.16
Weighted average number of shares outstanding:			
Basic	56,312	56,559	73,727
Diluted	56,312	56,737	74,664

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

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SandRidge Energy, Inc. and Subsidiaries

Consolidated Statements of Changes in Stockholders Equity

	Preferred Stock	Common Stock	Additional Paid-In Capital	Deferred Compensation	Treasury Stock	Retained Earnings	Total
			(Restated for 2004, 2005 and 2006) (In thousands)				
Balance, January 1, 2004 (previously reported)	$ 23	$ 200	$	$	$	$ 27,628	$ 27,851
Prior period adjustments						6,090	6,090
Balance, January 1, 2004 (restated)	23	200				33,718	33,941
Net income						25,392	25,392
Dividends on preferred stock						(2)	(2)
Balance, December 31, 2004	23	200				59,108	59,331
Exchange of preferred stock for common stock	(23)	1	22				
Purchase of treasury shares		(5)			(17,335)		(17,340)
Stock split (change in par value)		(141)	141				
Issuance of stock in acquisitions		4	55,281				55,285
Stock offering, net of $18.0 million in offering costs		12	173,110				173,122
Restricted shares		2	15,366	(15,366)			2
Amortization of deferred compensation				481			481
Net income						18,122	18,122
Dividends on preferred stock						(1)	(1)
Balance, December 31, 2005		73	243,920	(14,885)	(17,335)	77,229	289,002
Stock offering			3,343				3,343
Change in accounting principle for stock-based compensation			(14,885)	14,885			
Issuance of stock in acquisitions		13	236,271				236,284
		6	97,427				97,433

Stock offering, net of $3.9 million in offering costs							
Stock-based compensation			8,792				8,792
Accretion on redeemable convertible preferred stock						(157)	(157)
Purchase of treasury shares					(500)		(500)
Net income						15,621	15,621
Balance, December 31, 2006	$	$ 92	$ 574,868	$	$ (17,835)	$ 92,693	$ 649,818

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

SandRidge Energy, Inc. and Subsidiaries

Consolidated Statements of Cash Flows

	Years Ended December 31, 2004 (Restated)	2005 (Restated) (In thousands)	2006 (Restated)
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 25,392	$ 18,122	$ 15,621
Income from discontinued operations, net of tax	451	229	
Income from continuing operations	24,941	17,893	15,621
Adjustments to reconcile net income to net cash provided by operating activities:			
Provision for doubtful accounts	761	33	2,528
Depreciation, depletion and amortization	12,674	24,206	55,626
Debt issuance cost amortization			299
Deferred income taxes	6,433	9,460	348
Extraordinary gain	(12,544)		
Unrealized loss (gain) on derivatives	(1,803)	1,296	1,878
Loss (gain) on sale of assets	(210)	547	(1,023)
Interest income restricted deposits			(151)
Loss (gain) from equity investments, net of distributions	1,066	846	(956)
Stock-based compensation		481	8,792
Minority interests	262	737	296
Changes in operating assets and liabilities increasing (decreasing) cash:			
Receivables	(6,950)	(25,494)	(2,648)
Inventories	(481)	(46)	(938)
Other current assets	(584)	(1,146)	(22,238)
Other assets and liabilities, net	324	775	(2,131)
Accounts payable and accrued expenses	14,569	33,709	12,046
Net cash provided by operating activities by continuing operations	38,458	63,297	67,349
Net cash provided by operating activities by discontinued operations	978	347	
Net cash provided by operating activities	39,436	63,644	67,349
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures for property, plant and equipment	(57,926)	(134,596)	(306,541)
Proceeds from sale of assets	1,443	3,327	19,742
Contributions on equity investments	(1,976)	(1,350)	(3,388)
Acquisitions of assets, net of cash received of $0, $66 and $21,100	(1,169)	(21,247)	(1,054,075)
Proceeds from sale of investments	220	413	2,373
Restricted deposits			(1,051)

Restricted cash		(2,373)	2,373
Net cash used in investing activities for continuing operations	(59,408)	(155,826)	(1,340,567)
Net cash used in investing activities for discontinued operations	(1,931)	(1,473)	
Net cash used in investing activities	(61,339)	(157,299)	(1,340,567)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	41,620	247,460	1,261,910
Repayments of borrowings	(6,840)	(301,285)	(518,870)
Dividends paid-preferred	(2)	(1)	
Minority interests contributions (distributions)	(78)	7,117	(618)
Proceeds from issuance of common stock		173,122	100,776
Proceeds from issuance of redeemable convertible preferred stock			439,486
Purchase of treasury shares			(500)
Debt issuance costs			(15,749)
Net cash provided by financing activities for continuing operations	34,700	126,413	1,266,435
Net cash provided by financing activities for discontinued operations			
Net cash provided by financing activities	34,700	126,413	1,266,435
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	12,797	32,758	(6,783)
CASH AND CASH EQUIVALENTS, beginning of year	176	12,973	45,731
CASH AND CASH EQUIVALENTS, end of year	$ 12,973	$ 45,731	$ 38,948
Supplemental Disclosure of Cash Flow Information:			
Cash paid for interest, net of amounts capitalized	$ 2,024	$ 7,222	$ 15,079
Cash paid for income taxes			1,599
Supplemental Disclosure of Noncash Investing and Financing Activities:			
Common stock issued in connection with acquisitions	$	$ 55,285	$ 236,284
Assumption of restricted deposits and notes payable in connection with acquisition			313,628
Assets disposed in exchange for common stock		17,335	
Insurance premium financed	1,137	2,133	5,023
Accretion on redeemable convertible preferred stock			157

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

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SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements
(Restated)

1. Summary of Significant Accounting Policies

Nature of Business. SandRidge Energy, Inc. and its subsidiaries (formerly known as Riata Energy Inc.) (collectively, the Company or SandRidge) is an oil and gas company with its principal focus on exploration, development and production related to oil and gas activities. SandRidge also owns and operates drilling rigs and provides related oil field services, midstream gas services operations, and CO_2 and tertiary oil recovery operations. SandRidge s primary exploration, development and production areas are concentrated in West Texas. The Company also operates significant interests in the Cotton Valley Trend in East Texas and Gulf Coast area.

On November 21, 2006, the Company acquired all of the outstanding membership interests of NEG Oil & Gas LLC (NEG) (See Note 3).

Principles of Consolidation. The consolidated financial statements include the accounts of SandRidge Energy, Inc. and its wholly owned or majority owned subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation.

Reclassifications. Certain reclassifications have been made in prior period financial statements to conform with current period presentation.

Restatement. The Company has restated the consolidated financial statements for the year ended December 31, 2006. The restatement relates to the loss (gain) on derivative contracts in the statement of operations. In 2006, the Company recognized an unrealized gain on change in fair value of derivatives related to mark-to-market adjustments of derivative contracts with a counterparty for approximately $3.0 million. The Company recently discovered that the mark-to-market adjustments booked in 2006 for the derivative contracts with this counterparty were recorded incorrectly. As part of its normal closing procedures, the Company requests from the counterparty the Company s mark-to-market position. Historically, the Company s counterparties have sent the statement in terms of SandRidge s position. During the fourth quarter of 2006, the Company entered into derivative contracts with a new counterparty. The new counterparty confirmed to the Company the mark-to-market loss (gain) in their position, not the Company s. The position terms of the statement were not specified on the report and recorded in error during the 2006 year end closing process. As part of the first quarter 2007 closing process, the Company discovered the error.

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SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Restated) (Continued)

The restatement affects Note 12 Derivatives, Note 14 Income Taxes, and Note 21 Industry Segment Information. The restatement had no effect on the Company s previously presented net cash provided by (used in) operating activities, investing activities, or financing activities for any period presented. A comparison of the Company s previously presented deferred tax assets, derivative contracts current assets, derivative contracts non current assets, derivative contracts current liabilities, derivative contracts non current liabilities, deferred tax liabilities, and retained earnings to its restated financial position disclosed herein are as follows (in thousands):

	December 31, 2006 (As originally presented)	December 31, 2006 (As restated)
Deferred tax assets	$ 5,244	$ 6,315
Derivative contracts current assets	$ 279	$
Derivative contracts non current assets	$ 1,736	$
Derivative contracts current liabilities	$	$ 958
Derivative contracts non current liabilities	$	$ 3,052
Deferred tax liabilities	$ 26,020	$ 24,922
Retained earnings	$ 96,549	$ 92,693

A comparison of the Company s previously presented net income, income available to common stockholders, and earnings per share to its results of operations disclosed herein are as follows (in thousands, except per share amounts):

	2006 (As originally presented)	2006 (As restated)
Net income	$ 19,477	$ 15,621
Income available to common stockholders	$ 15,510	$ 11,654
Basic and diluted earnings per share available to common stockholders	$ 0.21	$ 0.16

Change in Method of Accounting for Oil and Gas Operations. In the fourth quarter of 2006, the Company changed from the successful efforts method to the full cost method of accounting for its oil and gas operations. All prior year s financial statements presented herein have been restated to reflect the change.

Management believes that the full cost method is preferable for a company more actively involved in the exploration and development of oil and gas reserves. The full cost method was also utilized by NEG prior to the acquisition, and the assets acquired from NEG constitute more than SandRidge s total oil and gas assets.

SandRidge s financial results have been retroactively restated to reflect the conversion to the full cost method. As prescribed by full cost accounting rules, all costs associated with property acquisition, exploration, and development activities are capitalized. Exploration and development costs include dry hole costs, geological and geophysical costs, direct overhead related to exploration and development activities and other costs incurred for the purpose of finding oil and gas reserves.

In accordance with full cost accounting rules, SandRidge is subject to a limitation on capitalized costs. The capitalized cost of oil and gas properties, net of accumulated depreciation, depletion, and amortization, may not exceed the estimated future net cash flows from proved oil and gas reserves discounted at 10%, plus the lower of cost or fair market value of unproved properties as adjusted for related tax effects. If capitalized

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Notes to Consolidated Financial Statements (Restated) (Continued)

costs exceed this limit (the ceiling limitation), the excess must be charged to expense. SandRidge did not have any adjustment to earnings due to the ceiling limitation for the periods presented herein.

A comparison of the Company s previously presented property, plant and equipment, net, deferred income taxes and retained earnings under the successful efforts method of accounting to its financial position disclosed herein are as follows (in thousands):

	December 31, 2005 (As originally presented)	December 31, 2005 (As restated)
Property, plant and equipment, net	$ 318,284	$ 337,881
Deferred tax liabilities	$ 6,857	$ 13,747
Retained earnings	$ 64,522	$ 77,229

A comparison of the Company s previously presented income from continuing operations, net income, and earnings per share under the successful efforts method of accounting to its results of operations disclosed herein are as follows (in thousands, except per share amounts):

	Year Ended December 31	
	2004	2005
Income from continuing operations, as originally presented	$ 8,327	$ 15,346
Net income, as originally presented	$ 21,322	$ 15,575
Basic and diluted earnings per share, as originally presented	$ 0.38	$ 0.28
Income from continuing operations, as restated	$ 12,397	$ 17,893
Net income, as restated	$ 25,392	$ 18,122
Basic and diluted earnings per share, as restated	$ 0.45	$ 0.32

Use of Estimates. The preparation of the consolidated 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 and 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.

Estimates of oil and natural gas reserves and their values, future production rates and future costs and expenses are inherently uncertain for numerous reasons, including many factors beyond the Company s control. Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of data available and of engineering and geological interpretation and judgment. In addition, estimates of reserves may be revised based on actual production, results of subsequent exploitation and development activities, prevailing commodity prices, operating cost and other factors. These revisions may be material and could materially affect the Company s future depletion, depreciation and amortization expenses.

The Company s revenue, profitability, and future growth are substantially dependent upon the prevailing and future prices for oil and natural gas, which are dependent upon numerous factors beyond its control such as economic, regulatory developments and competition from other energy sources. The energy markets have historically been volatile and there can be no assurance that oil and natural gas prices will not be subject to wide fluctuations in the future. A substantial or extended decline in oil and natural gas prices could have a

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Restated) (Continued)

material adverse effect on the Company s financial position, results of operations, cash flows and quantities of oil and natural gas reserves that may be economically produced.

Cash and Cash Equivalents. The Company considers all highly-liquid instruments with a maturity of three months or less when purchased to be cash equivalents. Those securities are readily convertible to known amounts of cash and bear insignificant risk of changes in value due to their short maturity period.

Restricted Cash. Restricted cash of approximately $2.4 million at December 31, 2005 was pledged as collateral on certain bank debt and is classified as restricted cash on the consolidated balance sheets. The restriction was released in April 2006.

Accounts Receivable, net. The Company has receivables for sales of oil, gas and natural gas liquids, as well as receivables related to the exploration and extraction services for oil, gas and natural gas liquids. Management has established an allowance for doubtful accounts. The allowance is evaluated by management and is based on management s periodic review of the collectibility of the receivables in light of historical experience, the nature and volume of the receivables, and other subjective factors.

Inventories. Inventories consist of oil field services supplies and are stated at the lower of cost or market with cost determined on an average cost basis.

Goodwill. Goodwill represents the amount by which the total purchase price SandRidge has paid to acquire businesses accounted for as purchases exceeds the estimated fair value of the net assets acquired. The Company tests goodwill for impairment annually and charges income for any impairment recognized, but goodwill is not otherwise amortized.

Debt Issue Costs. The Company amortizes debt issue costs related to its senior credit facility and senior bridge facility as interest expense over the scheduled maturity period of the debt. Unamortized debt issuance costs were $0 as of December 31, 2005 and approximately $15.5 million as of December 31, 2006. The Company includes those unamortized costs in other assets.

Revenue Recognition and Gas Balancing. Oil and natural gas revenues are recorded when title passes to the customer, net of royalties, discounts and allowances, as applicable. The Company accounts for oil and natural gas production imbalances using the sales method, whereby the Company recognizes revenue on all oil and natural gas sold to its customers notwithstanding the fact that its ownership may be less than 100% of the oil and natural gas sold. Liabilities are recorded by the Company for imbalances greater than the Company s proportionate share of remaining estimated oil and natural gas reserves. The Company did not have significant gas imbalance positions at December 31, 2005. The Company has recorded a liability for gas imbalance positions related to gas properties with insufficient proved reserves of $0.9 million at December 31, 2006. The Company includes the gas imbalance positions in other long-term obligations.

The Company recognizes revenues and expenses generated from daywork drilling contracts as the services are performed, since the Company does not bear the risk of completion of the well. Under footage and turnkey contracts, the Company bears the risk of completion of the well; therefore, revenues and expenses are recognized when the well is substantially completed. Under this method, substantial completion is determined when the well bore reaches the negotiated depth as stated in the contract. The duration of all three types of contracts range typically from 20 to 90 days. The entire amount of a loss, if any, is recorded when the loss is determinable. The costs of uncompleted drilling contracts include expenses incurred to date on footage or turnkey contracts, which are still in process at the end of the period.

The Company may receive lump-sum fees for the mobilization of equipment and personnel. Mobilization fees received and costs incurred to mobilize a rig from one market to another are recognized over the term of the related drilling contract. The contract terms are typically from 20 to 90 days.

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Notes to Consolidated Financial Statements (Restated) (Continued)

Revenues from the midstream gas services segment are derived from providing supply, transportation, balancing and sales services for producers and wholesale customers on natural gas pipelines, as well as other interconnected pipeline systems. Midstream gas services are primarily undertaken to realize incremental margins on gas purchased at the wellhead, and provide value-added services to customers. In general, natural gas purchased and sold by the midstream gas business is priced at a published daily or monthly index price. Sales to wholesale customers typically incorporate a premium for managing their transmission and balancing requirements. Revenues are recognized upon delivery of natural gas to customers and/or when services are rendered, pricing is determinable and collectibility is reasonably assured.

Revenue from sales of CO_2 is recognized when the product is delivered to the customer. The Company recognizes service fees related to the transportation of CO_2 as revenue when the related service is provided.

Environmental Costs. Environmental expenditures are expensed or capitalized, as appropriate, depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and that do not have future economic benefit, are expensed. Liabilities related to future costs are recorded on an undiscounted basis when environmental assessments and/or remediation activities are probable and costs can be reasonably estimated. Environmental costs accrued at December 31, 2005 and 2006 were not material.

Oil and Natural Gas Operations. The Company uses the full cost method to account for its natural gas and oil properties. Under full cost accounting, all costs directly associated with the acquisition, exploration and development of natural gas and oil reserves are capitalized into a full cost pool. These capitalized costs include costs of all unproved properties, internal costs directly related to the Company s acquisition, exploration and development activities and capitalized interest. These costs are amortized using a unit-of-production method. Under this method, the provision for depreciation, depletion and amortization is computed at the end of each quarter by multiplying total production for such quarter by a depletion rate. The depletion rate is determined by dividing the total unamortized cost base by net equivalent proved reserves at the beginning of the quarter.

Costs associated with unproved properties are excluded from the total unamortized cost base until a determination has been made as to the existence of proved reserves. Unproved properties are reviewed at the end of each quarter to determine whether the costs incurred should be reclassified to the full cost pool and, thereby, subject to amortization. Sales and abandonments of natural gas and oil properties being amortized are accounted for as adjustments to the full cost pool, with no gain or loss recognized, unless the adjustments would significantly alter the relationship between capitalized costs and proved natural gas and oil reserves. A significant alteration would not ordinarily be expected to occur upon the sale of reserves involving less than 25% of the reserve quantities of a cost center.

Under full cost accounting, total capitalized costs (net of accumulated depreciation, depletion and amortization) less related deferred taxes may not exceed an amount equal to the present value of future net revenues from proved reserves, discounted at 10% per annum, plus the lower of cost or fair value of unevaluated properties, plus estimated salvage value, less income tax effects (the ceiling limitation). A ceiling limitation calculation is performed at the end of each quarter. If total capitalized costs (net of accumulated depreciation, depletion and amortization) less related deferred taxes are greater than the ceiling limitation, a write-down or impairment of the full cost pool is required. A write-down of the carrying value of the full cost pool is a non-cash charge that reduces earnings and impacts stockholders equity in the period of occurrence and typically results in lower depreciation, depletion and amortization expense in future periods. Once incurred, a write-down is not reversible at a later date.

The ceiling test is calculated using natural gas and oil prices in effect as of the balance sheet date, as adjusted for basis or location differentials as of the balance sheet date and held constant over the life of the reserves (net wellhead prices). If applicable, these net wellhead prices would be further adjusted to include the effects of any fixed price arrangements for the sale of natural gas and oil. The Company may, from time-

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Restated) (Continued)

to-time, use derivative financial instruments to hedge against the volatility of natural gas prices. Derivative contracts that qualify and are designated as cash flow hedges and, are included in estimated future cash flows. Historically, the Company has not designated any of its derivative contracts as cash flow hedges. In addition, the future cash outflows associated with future development wells are included in the computation of the discounted present value of future net revenues for the purposes of the ceiling test calculation.

The costs associated with unproved properties are not initially included in the amortization base and relate to unproved leasehold acreage, wells and production facilities in progress and wells pending determination of the existence of proved reserves, together with capitalized interest costs for these projects. Unproved leasehold costs are transferred to the amortization base with the costs of drilling the related well once a determination of the existence of proved reserves has been made or upon impairment of a lease. Costs of seismic data are allocated to various unproved leaseholds and transferred to the amortization base with the associated leasehold costs on a specific project basis. Costs associated with wells in progress and completed wells that have yet to be evaluated are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property. Costs of dry holes are transferred to the amortization base immediately upon determination that the well is unsuccessful. The Company capitalized exploration expense of $3.7 million in 2004, $2.1 million in 2005 and $13.7 million in 2006.

All items classified as unproved property are assessed on a quarterly basis for possible impairment or reduction in value. Properties are assessed on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

Property, Plant and Equipment, net. Other capitalized costs, including drilling equipment, natural gas gathering and processing equipment, transportation equipment and other property and equipment are carried at cost. Renewals and improvements are capitalized while repairs and maintenance are expensed. Depreciation of drilling equipment is recorded using the straight-line method based on estimated useful lives. Depreciation of other property and equipment is computed using the straight-line method over the estimated useful lives of the assets ranging from 3 to 39 years.

Realization of the carrying value of property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset including disposal value if any, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. An estimate of fair value is based on the best information available, including prices for similar assets. Changes in such estimates could cause the Company to reduce the carrying value of property and equipment.

When property and equipment components are disposed of, the cost and the related accumulated depreciation are removed from the accounts and any resulting gain or loss is generally reflected in operations.

Investments. Investments in affiliated companies are accounted for under the cost or equity method, based on the Company s ability to exercise significant influence.

Asset Retirement Obligation. The Company owns oil and natural gas properties which require expenditures to plug and abandon the wells when the oil and natural gas reserves in the wells are depleted. These expenditures are recorded in the period in which the liability is incurred (at the time the wells are drilled or acquired). Asset retirement obligations are recorded as a liability at their estimated present value at the asset s

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Notes to Consolidated Financial Statements (Restated) (Continued)

inception, with the offsetting charge to property cost. Periodic accretion expense of the estimated liability is recorded in the statement of operations.

The asset retirement obligations primarily represent the Company s estimate of fair value to plug, abandon and remediate the oil and natural gas properties at the end of their productive lives, in accordance with applicable state laws. The Company has determined the asset retirement obligations by calculating the present value of estimated expenses related to the liability. Estimating the future asset retirement obligations requires management to make estimates and judgments regarding timing, existence of a liability, and what constitutes adequate restoration. Inherent in the present value calculation rates, are the timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligations liability, a corresponding adjustment is made to the related asset. The following is a reconciliation of the asset retirement obligation for the years ended December 31, (in thousands).

	2004	2005	2006
Asset retirement obligation, January 1	$ 3,883	$ 4,394	$ 6,979
Liability incurred upon acquiring and drilling wells	372	2,779	2,996
NEG acquisition			40,343
Revisions in estimated cash flows			(5,700)
Liability settled in current period		(512)	
Accretion of discount expense	139	318	598
Asset retirement obligation, December 31	$ 4,394	$ 6,979	$ 45,216

Income Taxes. Deferred income taxes are provided on temporary differences between financial statement and income tax reporting. Temporary differences are differences between the amounts of assets and liabilities reported for financial statement purposes and their tax bases. Deferred tax assets are recognized for temporary differences that will be deductible in future years tax returns and for operating loss and tax credit carryforwards. Deferred tax assets are reduced by a valuation allowance if it is deemed more likely than not that some or all of the deferred tax assets will not be realized. Deferred tax liabilities are recognized for temporary differences that will be taxable in future years tax returns.

Minority Interest. As of December 31, 2006, minority interest in the Company s consolidated subsidiaries consisted of the following:

- the 15.00% interest in Integra Energy;
- the 30.38% interest in Sagebrush Pipeline; and
- the 46.71% interest in Cholla Pipeline.

Concentration of Risk. The Company maintains cash balances at several banks. Accounts at each institution are insured by the Federal Deposit Insurance Corporation up to $100,000. From time to time, the Company may have balances in these accounts that exceed the federally insured limit. The Company does not anticipate any loss associated with balances in excess of the federally insured limit.

Fair Value of Financial Instruments. For certain of the Company s financial instruments, including cash, accounts receivable and accounts payable, the carrying value approximates fair value because of their short maturity. The carrying value of borrowings under the senior credit facility and the notes payable approximates fair value because their interest rates are based on fair value indexes. The fair value of the Company s senior bridge facility and convertible preferred stock approximate book value based on current material transactions completed by the Company subsequent to year end.

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Derivative Financial Instruments. To manage risks related to increases in interest rates and changes in oil and gas prices, the Company occasionally enters into interest rate swaps and oil and gas futures contracts.

The Company recognizes all of its derivative instruments as either assets or liabilities at fair value. The accounting for changes in the fair value (i.e., gains or losses) of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship, and further, on the type of hedging relationship. For those derivative instruments that are designated and qualify as hedging instruments, the Company designates the hedging instrument, based on the exposure being hedged, as either a fair value hedge or a cash flow hedge. For derivative instruments not designated as hedging instruments, the gain or loss is recognized in current earnings during the period of change. None of the Company s derivatives were designated as hedging instruments during 2004, 2005 and 2006.

Stock-Based Compensation. Effective January 1, 2006, the Company adopted SFAS No. 123-R, Share-Based Payment (SFAS 123R). SFAS 123R establishes the accounting for equity instruments exchanged for employee services. Under SFAS 123R, share-based compensation cost is measured at the grant date based on the calculated fair value of the award. The expense is recognized over the employees requisite service period, generally the vesting period of the award. SFAS 123R also requires the related excess tax benefit received upon exercise of stock options or vesting of restricted stock, if any, to be reflected in the statement of cash flows as a financing activity rather than an operating activity. The Company does not have any excess tax benefits.

Recent Accounting Pronouncements. In July 2006, the Financial Accounting Standards Board (FASB) issued FIN 48, Accounting for Uncertainty in Income Taxes, or FIN 48, which is effective for the Company as of the interim reporting period beginning January 1, 2007. The validity of any tax position is a matter of tax law, and generally there is no controversy about recognizing the benefit of a tax position in a company s financial statements when the degree of confidence is high that the tax position will be sustained upon examination by a taxing authority. The tax law is subject to varied interpretation, and whether a tax position will ultimately be sustained may be uncertain. Under FIN 48, the impact of an uncertain income tax position on the income tax provision must be recognized at the largest amount that is more likely than not to be sustained upon audit by the relevant taxing authority. A benefit based on an uncertain income tax position will not be recognized if it has less than a 50% likelihood of being sustained. FIN 48 also requires additional disclosures about unrecognized tax benefits associated with uncertain income tax positions and a reconciliation of the change in the unrecognized benefit. In addition, FIN 48 requires interest to be recognized on the full amount of deferred benefits for uncertain tax positions. An income tax penalty is recognized as expense when the tax position does not meet the minimum statutory threshold to avoid the imposition of a penalty. The Company continues to evaluate the impact of FIN 48 on the consolidated financial statements. At this time, the Company is evaluating the impact of FIN 48.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements, which establishes a formal framework for measuring fair values of assets and liabilities in financial statements that are already required by U.S. generally accepted accounting principles (GAAP) to be measured at fair value. SFAS No. 157 clarifies guidance in FASB Concepts Statement (CON) No. 7 which discusses present value techniques in measuring fair value. Additional disclosures are also required for transactions measured at fair value. No new fair value measurements are prescribed, and SFAS No. 157 is intended to codify the several definitions of fair value included in various accounting standards. However, the application of this Statement may change current practices for certain companies. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. The Company is currently evaluating the impact of adopting SFAS No. 157 on the financial statements.

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 (SFAS No. 159), which permits an entity to choose to measure certain financial assets and liabilities at fair value. SFAS No. 159 also revises provisions of SFAS No. 115 that apply to available-for-sale and trading securities. This statement is

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Notes to Consolidated Financial Statements (Restated) (Continued)

effective for fiscal years beginning after November 15, 2007. The Company has not yet evaluated the potential impact of this standard.

2. Goodwill

In accordance with SFAS No. 142, Goodwill and Other Intangible Assets, the Company performs an annual impairment test (or more frequently if impairment indicators arise) for goodwill and other intangibles with indefinite lives. The Company allocates goodwill to various reporting units to perform its impairment test. SFAS No. 142 requires that the implied fair value of the reporting unit be compared with its carrying amount on an annual basis to determine if there is a potential impairment. If the fair value of the reporting unit is less than its carrying value, the Company would record an impairment loss to the extent of that difference. The Company bases the fair values of its reporting units on a combination of valuation approaches, including discounted cash flows, multiples of sales and earnings before interest, taxes, depreciation, depletion and amortization and comparisons of recent transactions. In the fourth quarter of 2006, the Company conducted its annual valuation test and determined it was not required to recognize any goodwill impairment. As of December 31, 2005, the Company had no intangible assets and goodwill. As of December 31, 2006, the Company had no intangible assets.

The change in the carrying amount of goodwill for 2006 was as follows (in thousands):

	2006
Balance at January 1, 2006	$
Acquisition	26,198
Balance at December 31, 2006	$ 26,198

3. Acquisitions and Dispositions

2005 Acquisitions

The Company closed the following acquisitions in 2005:

The acquisition of additional equity interests in PetroSource, which increased the Company s ownership from 22.4% to 86.5%, resulting in the consolidation of PetroSource in the Company s financial statements;

The acquisition from an executive officer and director of the remaining 50% equity interest in the Company s compression services subsidiary, Larco, resulting in it becoming a wholly-owned subsidiary;

The acquisition from an executive officer and director of approximately 7,400 net acres of additional leasehold interest in West Texas in properties in which the Company previously held interests;

The acquisition of approximately 2,503 net acres of additional leasehold interest in property in the Piceance Basin in which the Company previously held interests;

The acquisition from a director of additional working interests in Missouri and Nevada leases in which the Company previously held interests;

The acquisition of an additional 19.5% before pay-out interest in the Company s subsidiary, Sagebrush Pipeline LLC; and

The acquisition of certain interests in several oil and natural gas properties in West Texas from Carl E. Gungoll Exploration, LLC and certain other parties. The purchase price was approximately $8.0 million, comprised of $5.4 million in cash, and 174,833 shares of common stock (valued at $2.6 million).

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Restated) (Continued)

The acquisitions were financed with approximately $21.3 million in cash and the issuance of 3,685,690 shares of common stock with an aggregate value of approximately $55.3 million. Details are set forth below for each of the acquisition transactions (in thousands):

Acquisition Transaction	Addition to Property, Plant & Equipment	Addition to Net Assets(1)	Elimination of Investments	Change in Minority Interest	Consideration Paid: Common Stock No. of Shares	Consideration Paid: Common Stock at $15/Share	Consideration Paid: Cash, Net of Cash Acquired
PetroSource additional interests	$ 73,744	$ (37,381)	$ (3,052)	$ 3,253	958	$ 14,372	$ 15,686
Piceance Basin additional interests	17,565				1,164	17,456	109
West Texas additional lease interests	10,000				667	10,000	
Larco remaining interest	5,054			(2,446)	500	7,500	
Gungoll lease interests	8,074				176	2,622	5,452
Various additional lease interests	268				17	268	
Sagebrush additional interests	689			(2,378)	204	3,067	
Totals	$ 115,394	$ (37,381)	$ (3,052)	$ (1,571)	3,686	$ 55,285	$ 21,247

(1) The purchase price for additional interests in PetroSource was approximately $30.1 million, comprised of $15.7 million in cash (net of $0.1 million in cash acquired), and approximately 958,000 shares of SandRidge common stock (valued at $14.4 million). The purchase price has been allocated to accounts receivable of $4.5 million, other current assets of $0.1 million, other assets of $0.4 million, accounts payable and accrued expenses of $2.6 million, long-term debt of $37.4 million, and asset retirement obligations of $2.4 million in the accompanying consolidated balance sheet as of December 31, 2005.

The Company completed its purchase accounting allocations for the 2005 acquisitions in 2006 and recorded an additional $3.8 million deferred tax liability related to the Larco stock acquisition.

2006 Acquisitions and Dispositions

The Company closed the following acquisitions and dispositions in 2006:

On March 15, 2006, the Company acquired from an executive officer and director, an additional 12.5% interest in PetroSource Energy Company, a consolidated subsidiary. The acquisition consisted of the retirement of subordinated debt of approximately $1.0 million and a $4.5 million cash payment for the ownership interest acquired for a total acquisition price of approximately $5.5 million.

On May 1, 2006, the Company purchased certain leases in developed and undeveloped properties from an oil and gas company. The purchase price was approximately $40.9 million in cash. The cash consideration was paid in July 2006.

On May 26, 2006, the Company purchased several oil and natural gas properties from an oil and gas company. The purchase price was approximately $12.9 million, comprised of $8.2 million in cash, and 251,351 shares of SandRidge Energy, Inc. common stock (valued at $4.7 million). The cash and equity consideration was paid in July 2006.

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Notes to Consolidated Financial Statements (Restated) (Continued)

On June 1, 2006, the Company purchased certain producing well interest from an executive officer and director. The purchase price was approximately $9.0 million in cash. The cash consideration was paid in July 2006.

On June 7, 2006, the Company acquired subordinated debt plus accrued interest of approximately $0.1 million and the remaining 1% interest in PetroSource Energy Company, a consolidated subsidiary, from an oil and gas company. The purchase price was 27,749 shares of SandRidge Energy, Inc. common stock (valued at $0.5 million). The Company now owns 100% of PetroSource Energy Company.

The preceding 2006 acquisitions were financed with approximately $63.7 million in cash and the issuance of 279,100 shares of common stock with an aggregate value of approximately $5.1 million. Details are set forth below for each of the acquisition transactions (in thousands):

				Consideration Paid		
Acquisition Transaction	**Addition to Property, Plant & Equipment**	**Change in Minority Interest**	**Retirement of Subordinated Debt(1)**	**Common Stock No. of Shares**	**Common Stock**	**Cash**
PetroSource additional interests March 15, 2006	$ 2,116	$ (2,370)	$ (1,003)		$	$ 5,489
Purchased leases May 1, 2006	40,960					40,960
Oil and natural gas properties May 26, 2006	12,850			251	4,650	8,200
Producing well interest from an executive officer and director June 1, 2006	9,000					9,000
PetroSource additional interest (remaining 1% interest) June 7, 2006	85	(393)		28	478	
Totals	$ 65,011	$ (2,763)	$ (1,003)	279	$ 5,128	$ 63,649

(1) Includes retirement of subordinated debt of $972,000 and accrued interest of $31,000.

In July 2006, the Company sold leaseholds and lease and well equipment for $16.0 million. The book basis of the assets at the time of the sale transaction was $3.7 million. The sale was accounted for as an adjustment to the full cost pool, with no gain recognized.

In August 2006, the Company sold certain assets (Stockton Plaza, Authentix Investment and certain other assets) to the Company s former President and Chief Operating Officer, N. Malone Mitchell, 3rd, for approximately $6.1 million in cash. These investments had been accounted for under the cost method and reflected as investments in the consolidated balance sheet as of December 31, 2005. The sale transaction resulted in a $0.8 million gain recognized in earnings by the Company in August 2006. The gain is included in loss (gain) on sale of assets in the consolidated statements of operations.

On November 21, 2006, the Company acquired all of the outstanding membership interests of NEG for approximately $990.4 million in cash, the assumption of $300 million in debt, the receipt of cash of $21.1 million, and the issuance of 12,842,000 shares of SandRidge Energy, Inc. common stock (valued at approximately $231.2 million). NEG owned core assets in the Val Verde and Permian Basins of West Texas, including overlapping or contiguous interests in the properties that the Company owns in the West Texas Overthrust. To finance the NEG acquisition, the Company entered into a new $750 million senior secured credit facility and an $850 million senior unsecured bridge loan facility. The Company also issued $550 million of redeemable convertible preferred stock and common units (consisting of

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Notes to Consolidated Financial Statements (Restated) (Continued)

shares of common stock and a warrant to purchase convertible preferred stock upon the surrender of the common stock) in a private placement to certain eligible purchasers.

The accompanying balance sheet at December 31, 2006 includes the allocations of the purchase price for the NEG acquisition. The allocation of the purchase price to specific assets and liabilities were based, in part, upon an appraisal of the fair value of NEG assets. The Company continues to obtain information to refine the fair value of the assets acquired and the liabilities assumed. The Company expects that a final allocation of the purchase price will be completed in fiscal year 2007.

The following table presents the NEG acquisition purchase price allocation, including professional fees and other related acquisition costs, to the net assets acquired and liabilities assumed, based on the fair values with the balance of the purchase price, $26.2 million, included in goodwill at the acquisition date (in thousands):

Cash and cash equivalents	$ 21,100
Accounts receivable	30,840
Other current assets	6,025
Property, plant and equipment	1,497,874
Goodwill	26,198
Restricted deposits	31,987
Other assets	270
Total assets acquired	1,614,294
Accounts payable and other current liabilities	46,082
Deferred income taxes	2,189
Long-term debt	281,641
Other long-term obligations	1,357
Asset retirement obligation	40,343
Net assets acquired	1,242,682
Less: Cash and cash equivalents acquired	(21,100)
Net amount paid for acquisition	$ 1,221,582

The Company has assigned all of the NEG goodwill to the Exploration and Production segment. Goodwill in the amount of $24.0 million is deductible for tax purposes.

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Restated) (Continued)

Pro Forma Information

The unaudited financial information in the table below summarizes the combined results of operations of SandRidge and NEG, on a pro forma basis, as though the companies had been combined as of January 1, 2005. The pro forma financial information is presented for informational purposes only and is not indicative of the results of operations that would have been achieved if the acquisition had taken place on January 1, 2005 or of results that may occur in the future. The pro forma adjustments include estimates and assumptions based on currently available information. The Company believes the estimates and assumptions are reasonable, and the significant effects of the transactions are properly reflected. However, actual results may differ materially from this pro forma financial information. The following table presents the actual results for the years ended December 31, 2005 and 2006 and the respective unaudited pro forma information to reflect the NEG acquisition (in thousands, except per share amounts):

	Year Ended December 31,			
	2005		2006	
	Actual	Pro Forma	Actual	Pro Forma
Revenues	$ 287,693	$ 560,235	$ 388,242	$ 565,256
Income (loss) from continuing operations	17,893	(49,594)	19,477	40,133
Net income (loss)	18,122	(49,594)	19,477	40,133
Basic and diluted earnings per share available (applicable) to common stockholders:				
Income (loss) from continuing operations	$ 0.31	$ (0.96)	$ 0.21	$ 0.04
Net income (loss) available to common stockholders	$ 0.32	$ (0.96)	$ 0.21	$ 0.04

4. Discontinued Operations

On September 30, 2005, the Company exchanged substantially all of its land and agriculture operations with its majority stockholder. The majority stockholder exchanged 1,414,849 shares of the Company s common stock for these operations. The shares were exchanged at their historical basis and the exchange was reflected as a treasury share transaction. The net book value of assets exchanged was $23.6 million. There was no gain (loss) recognized in this transaction. The land and agriculture operations are presented as discontinued operations, net of income taxes in the consolidated statements of operations.

The following table summarizes net revenue and net income (loss) from discontinued operations for the years ended December 31, 2004, 2005 and 2006 (in thousands):

	2004	2005	2006
Revenues	$ 1,968	$ 1,683	$
Operating expenses	(1,285)	(1,336)	

Income from discontinued operations		683		347	
Income tax expense		(232)		(118)	
Net income from discontinued operations	$	451	$	229	$

No assets were classified as held for sale at December 31, 2005 or 2006.

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Restated) (Continued)

5. Accounts Receivable

A summary of accounts receivable is as follows (in thousands):

	December 31, 2005	December 31, 2006
Oil and gas service	$ 12,809	$ 8,489
Oil and gas sales	29,113	57,458
Joint interest billing	18,109	26,553
Other		299
	60,031	92,799
Less allowance for doubtful accounts	(851)	(3,025)
Total accounts receivable, net	$ 59,180	$ 89,774

The following tables show the balance in the allowance for doubtful accounts and activity for the years ended December 31, 2004, 2005 and 2006 (in thousands).

Allowance for Doubtful Accounts	Balance at Beginning of Period	Additions Charged to Costs and Expenses	Deductions(1)	Balance at End of Period
Year ended December 31, 2004	$ 602	$ 761	$ (289)	$ 1,074
Year ended December 31, 2005	$ 1,074	$ 33	$ (256)	$ 851
Year ended December 31, 2006	$ 851	$ 2,528	$ (354)	$ 3,025

(1) Deductions represent the write-off/recovery of receivables.

6. Other Current Assets

Other current assets consist of the following (in thousands):

	December 31, 2005	December 31, 2006

Prepaid insurance	$ 2,369	$ 7,604
Prepaid drilling	407	2,207
Materials and supplies	83	6,244
Post closing receivable NEG acquisition		15,232
Other	385	207
Total other current assets	$ 3,244	$ 31,494

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SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Restated) (Continued)

7. Property, Plant and Equipment

Property, plant and equipment consists of the following (in thousands):

	December 31, 2005 (Restated)	December 31, 2006
Oil and natural gas properties:		
Proved	$ 160,789	$ 1,636,832
Unproved	33,974	282,374
Total oil and natural gas properties	194,763	1,919,206
Less accumulated depreciation and depletion	(35,029)	(60,752)
Net oil and natural gas properties capitalized costs	159,734	1,858,454
Land	852	738
Non oil and gas equipment	210,380	337,294
Buildings and structures	4,708	6,564
Construction in progress	267	
Total	216,207	344,596
Less accumulated depreciation, depletion and amortization	(38,060)	(68,332)
Net capitalized costs	178,147	276,264
Total property, plant and equipment	$ 337,881	$ 2,134,718

The amount of capitalized interest in 2006 was approximately $1.4 million and is included in the above non oil and gas equipment balance. The Company did not capitalize any interest in 2004 or 2005.

Costs Excluded

Costs associated with unproved properties related to continuing operations of $282.4 million as of December 31, 2006 are excluded from amounts subject to amortization. The majority of the evaluation activities are expected to be completed within a four-year period. In addition, the Company s internal engineers evaluate all properties on an annual basis. The average composite rates used for depreciation, depletion and amortization were $0.69 per Mcfe in 2004, $1.23 per Mcfe in 2005 and $1.68 per Mcfe in 2006.

Costs Excluded by Year Incurred (in thousands)

	Prior Years	Year Cost Incurred 2004	2005	2006	Excluded Costs at December 31, 2006
Property acquisition	$	$	$	$ 251,839	$ 251,839
Exploration				30,535	30,535
Development					
Capitalized interest					
Total costs incurred	$	$	$	$ 282,374	$ 282,374

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SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Restated) (Continued)

8. Investment in Affiliated Companies

The Company has certain investments that it accounts for under the equity method of accounting because its owns more than 20% and has significant influence but does not control. Additionally, the Company had various investments in other companies in which it did not have the ability to exercise significant influence and accounted for these investments under the cost method. The carrying values of these other investments were approximately $790,000 as of December 31, 2005 and were sold in 2006 (Note 3).

The equity method investments include the following:

Grey Ranch, L.P. Grey Ranch is primarily engaged in process and transportation of gas and natural gas liquids. The Company purchased its investment during 2003. At December 31, 2005 and 2006, the Company owned 50% of Grey Ranch, L.P. and had approximately $824,000 and $2,201,000, respectively, recorded in the consolidated balance sheets relating to this investment. The Company contributed a disproportionate amount of capital into the Partnership, amounting to approximately $217,000 and $750,000, respectively, as of December 31, 2005 and 2006. The excess amount contributed is being amortized over the average life of the partnership s long-lived assets.

Larclay, L.P. Larclay is a joint venture between the Company and Clayton Williams Energy, Inc. (CWEI) and was formed to acquire drilling rigs and provide land drilling services. The Company purchased its investment in 2006 and accounts for it under the equity method of accounting. The Company and CWEI each own 50% interest in the joint venture. The Company serves as the operations manager of the joint venture. CWEI is responsible for financing and purchasing of the rigs. At December 31, 2006, the Company had approximately $1,383,000 recorded in the consolidated balance sheet relating to this investment.

9. Restricted Deposits

Restricted deposits represent bank trust and escrow accounts required (by the U.S. Department of Interior s Minerals Management Service) to be set up to provide satisfaction of the Company s eventual responsibility to plug and abandon wells and remove structures when certain offshore fields are no longer in use. These restricted deposits were acquired as part of the NEG acquisition in November 2006 (See Note 3).

The restricted deposits include the following:

A $4.4 million escrow account for the East Breaks 109 and 110 fields set up in favor of the surety bond underwriter who provides a surety bond to the MMS. The escrow account is fully funded as of December 31, 2006.

A $7.2 million escrow account for the East Breaks 165 and 209 fields set up in favor of the surety bond underwriter who provides a surety bond to the former owners of the fields and the MMS. The escrow account is fully funded as of December 31, 2006.

A $6.6 million escrow account set up in favor of a major oil company. The Company is required to make additional deposits to the escrow account in an amount equal to 10% of the net cash flow (as defined in the escrow agreement) from the properties that were acquired from the major oil company.

A $6.2 million escrow account that was required to be set up by the bankruptcy settlement proceedings of NEG. The Company is required to make monthly deposits based on cash flows from certain wells, as defined in the agreement.

A $8.8 million escrow account required to be set up by the MMS relating to East Breaks properties. The Company is required to make quarterly deposits to the escrow account of $0.8 million. Additionally, for some of the East Break properties, the Company will be required to deposit additional funds in the East Break escrow accounts, representing the difference between the required escrow deposit under

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Restated) (Continued)

the surety bond and actual escrow deposit balance at various points in time in the future. Aggregate payments to the East Breaks escrow accounts are as follows (in thousands):

Years Ended December 31:	
2007	$ 3,200
2008	3,200
2009	3,200
2010 and none thereafter	1,657

10. Accounts Payable and Accrued Expenses

Accounts payable and accrued expenses consist of the following (in thousands):

	December 31, 2005	December 31, 2006
Accounts payable-trade	$ 69,937	$ 103,683
Payroll and benefits	1,091	10,718
Drilling advances	6,286	5,318
Legal (current)	15,643	5,000
Accrued interest	287	3,850
Other	2,191	1,230
Total accounts payable and accrued expenses	$ 95,435	$ 129,799

11. Long-Term Debt

Long-term obligations consist of the following (in thousands):

	December 31, 2005	December 31, 2006
Senior credit facility	$	$ 140,000
Senior bridge facility		850,000
Other notes payable:		
Drilling rig fleet and related oil field services equipment	34,710	61,105
Sagebrush	4,000	4,000
Insurance financing	1,450	7,240
Other equipment and vehicles	2,973	4,486

Total debt		43,133		1,066,831
Less: Current maturities of long-term debt		12,997		26,201
Long-term debt	$	30,136	$	1,040,630

Senior Credit Facility. On November 21, 2006, the Company entered into a $750 million senior secured revolving credit facility (the senior credit facility). The senior credit facility matures on November 21, 2011.

The proceeds of the senior credit facility were used to (i) partially finance the NEG acquisition, (ii) refinance the existing senior secured revolving credit facility and NEG s existing credit facility**,** and (iii) pay fees and expenses related to the NEG acquisition and the existing credit facility. Future borrowings under the senior credit facility will be available for capital expenditures, working capital and general corporate purposes and to finance permitted acquisitions of oil and gas properties and other assets related to the exploration, production and development of oil and gas properties. The senior credit facility will be available to be drawn

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Restated) (Continued)

on and repaid without restriction so long as the Company is in compliance with its terms, including certain financial covenants.

The senior credit facility contains various covenants that limit the Company and certain of its subsidiaries ability to grant certain liens; make certain loans and investments; make distributions; redeem stock; redeem or prepay debt; merge or consolidate with or into a third party; or engage in certain asset dispositions, including a sale of all or substantially all of the Company s assets. Additionally, the senior credit facility limits the Company and certain of its subsidiaries ability to incur additional indebtedness with certain exceptions, including under the senior unsecured bridge facility (as discussed below).

The senior credit facility also contains financial covenants, including maintenance of agreed upon levels for the ratio of (i) total funded debt to EBITDAX (as defined in the senior credit facility), (ii) EBITDAX to interest expense plus current maturities of long-term debt, and (iii) current ratio.

The obligations under the senior credit facility are secured by first priority liens on all shares of capital stock of each of the Company s present and future subsidiaries; all intercompany debt of the Company and its subsidiaries; and substantially all of the Company assets and the assets of its subsidiaries, including proven oil and gas reserves representing at least 80% of the present discounted value (as defined in the senior credit facility) of proven oil and gas reserves reviewed in determining the borrowing base for the senior credit facility. Additionally, the obligations under the senior credit facility will be guaranteed by certain Company subsidiaries.

The borrowing base of proved reserves was initially set at $300.0 million. As of December 31, 2006, the Company had $140.0 million of outstanding indebtedness on the senior credit facility.

At the Company s election, interest under the senior credit facility is determined by reference to (i) the British Bankers Association LIBOR rate, or LIBOR, plus an applicable margin between 1.25% and 2.00% per annum or (ii) the higher of the federal funds rate plus 0.5% or the prime rate plus, in either case, an applicable margin between 0.25% and 1.00% per annum. Interest will be payable quarterly for prime rate loans and at the applicable maturity date for LIBOR loans, except that if the interest period for a LIBOR loan is six months, interest will be paid at the end of each three-month period.

If an event of default exists under the senior credit facility, the lenders may accelerate the maturity of the obligations outstanding under the senior credit facility and exercise other rights and remedies. Each of the following will be an event of default:

failure to pay any principal when due or any interest, fees or other amount within certain grace periods;

failure to perform or otherwise comply with the covenants in the credit agreement or other loan

documents, subject, in certain instances, to certain grace periods;

bankruptcy or insolvency events involving the Company or its subsidiaries;

a change of control (as defined in the senior credit facility).

Senior Bridge Facility. On November 21, 2006, the Company also entered into a $850.0 million senior unsecured bridge facility (the senior bridge facility).

Together with borrowings under the senior credit facility, the proceeds from the senior bridge facility were used to (i) partially finance the NEG acquisition, (ii) refinance existing senior secured revolving credit facility and NEG s existing credit facility, and (iii) pay fees and expenses related to the NEG acquisition and the existing credit facility. The obligations under the senior bridge facility are general unsecured obligations of the company and certain of its subsidiaries.

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Restated) (Continued)

The senior bridge facility will nominally mature 12 months from the closing date for the facility (the Bridge Maturity Date), or November 21, 2007, subject to the automatic conversion described below. Any outstanding term loans on the Bridge Maturity Date will automatically be converted into new term loans with a five year term from the date of conversion (the Rollover Loans). On and after the Bridge Maturity Date, each bridge lender may elect to exchange its Rollover Loans for senior unsecured exchange notes (the Exchange Notes). Concurrent with the senior bridge facility, the Company entered into an Exchange Notes registration rights agreement whereby the Company is required to file a shelf registration with respect to resales of the Exchange Notes and have it declared effective no later than the Bridge Maturity Date and to keep such registration statement effective for as long as required by the holders to resell the Exchange Notes. If the Company fails to comply with the terms of the registration rights agreement the Company is required to pay liquidated damages of 0.5% per annum on the principal amount of Exchange Notes held for the first 90-day period, increasing 0.5% per annum for each 90-day period that the Company is in noncompliance, up to a maximum of 1.5% per annum.

The senior bridge facility contains customary restrictive covenants pertaining to management and operations of the Company and its subsidiaries similar to those contained in the senior credit facility. Generally, amounts outstanding under the senior bridge facility will bear interest at a base rate equal to the greater of (i) three-month LIBOR plus an applicable margin initially equal to 4.50% per annum or (ii) 9.0% per annum plus an applicable margin initially equal to 0% per annum; provided that the applicable margin for the senior bridge facility will increase by 0.5% at the end of the period that is six months after the closing date for the senior bridge facility and an additional 0.25% per quarter thereafter for as long as the senior bridge facility, Rollover Loans or Exchange Notes remain outstanding subject to a cap of 11% (subject to certain additional interest rate increases in certain circumstances). In addition, the senior bridge facility includes a covenant that obligates the Company to use commercially reasonable efforts to refinance the senior bridge facility as promptly as practicable. If the senior bridge facility is not refinanced or repaid within 12 months, the senior bridge facility will convert to a Rollover Loan described above on the same terms and interest rate as the senior bridge facility. The senior bridge facility also requires net proceeds from any new debt or equity offering to be applied to reduce indebtedness outstanding on the senior bridge facility. Generally, these covenants can be waived by lenders under the senior bridge facility that hold a majority of the indebtedness outstanding.

The senior bridge facility also includes events of default similar to those contained in the senior credit facility. If an event of default under the senior bridge facility shall occur and be continuing, the principal amount outstanding thereunder, together with all accrued unpaid interest and other amounts owed thereunder, may be declared immediately due and payable.

The Company repaid the senior bridge facility in March 2007 (See Note 20).

Other Indebtedness. The Company has financed a portion of its drilling rig fleet and related oil field services equipment through notes. At December 31, 2006, the aggregate outstanding balance of these credit agreements was $61.1 million, with a fixed interest rate ranging from 7.64% to 8.87%. The notes have a final maturity date of November 1, 2010, aggregate monthly installments for principal and interest in the amount of $1.2 million and are secured by the equipment. The notes have a prepayment penalty (currently 1-3%) in the event the Company repays the notes prior to maturity.

The Company has financed the purchase of various vehicles, oil field services equipment and other equipment. The aggregate outstanding balance of these notes as of December 31, 2006 was $4.5 million. Additionally, the Company has financed its insurance payment made in 2006. The aggregate outstanding balance of these notes as of December 31, 2006 was $7.2 million.

On October 14, 2005, Sagebrush Pipeline, LLC borrowed $4.0 million from Bank of America, N.A. for the purpose of completing the gas processing plant and pipeline in Colorado. This loan matures in July 2007,

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SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Restated) (Continued)

and the interest rate is LIBOR plus 215 basis points. The Company guaranteed this loan, and could be required to repay this debt in full. The Company owns approximately 70% of Sagebrush Pipeline, LLC. The Company anticipates that the Sagebrush members will make additional equity investments to Sagebrush to retire the debt when the loan matures.

Prior Senior Credit Facility. As of December 31, 2005, we had a $90 million revolving credit facility (the prior senior credit facility). The prior senior credit facility included a $20 million sub-limit for letters of credit. The prior senior credit facility was replaced by the senior credit facility as of November 21, 2006. Advances under the prior senior credit facility were subject to a borrowing base based on the Company s proved developed producing reserves, proved developed nonproducing reserves and proved undeveloped reserves. It was subject to re-determination semi-annually at the sole discretion of the lender based on the reports of independent petroleum engineers in accordance with normal and customary oil and gas lending practices.

The prior senior credit facility bore interest at the Company s option at either LIBOR plus 2.15% or the Bank of America, N.A. prime rate. The Company paid a commitment fee on the unused portion of the borrowing base amount equal to 1/8% per annum. The prior senior credit facility was collateralized by natural gas and oil properties representing at least 80% of the present discounted value of the Company s proved reserves and by a negative pledge on any of the Company s nonmortgaged properties.

As of December 31, 2005, the borrowing base under the Company s prior senior credit facility was $90 million and no amounts were outstanding.

Aggregate maturities of long-term debt during the next five years are as follows (in thousands):

Years Ended:	
2007	$ 26,201
2008	15,818
2009	16,863
2010	11,819
2011	146,130
Thereafter	850,000
Total debt	$ 1,066,831

12. Derivatives

The Company has entered into various derivative contracts including collars and fixed price swaps with a financial institution. The contracts expire on various dates through December 31, 2008.

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Restated) (Continued)

At December 31, 2006, the Company s open commodity derivative contracts consisted of the following:

Period	Commodity	Notional	Weighted Avg. Fix Price
Fixed price swap			
May 2007 - September 2007	Natural gas	3,060,000 MmBtu	$ 7.75
January 2008 - June 2008	Natural gas	3,640,000 MmBtu	$ 7.987
January 2008 - June 2008	Natural gas	3,640,000 MmBtu	$ 7.99
Collars			
January 2007 - December 2007	Crude oil	60,000 Bbls	$ 50.00 - $84.50
January 2008 - June 2008	Crude oil	42,000 Bbls	$ 50.00 - $83.35
July 2008 - December 2008	Crude oil	54,000 Bbls	$ 50.00 - $82.60
Waha basis swap			
January 2007 - December 2007	Natural gas	14,600,000 MmBtu	$ (0.70)
January 2007 - December 2007	Natural gas	7,300,000 MmBtu	$ (0.5925)
May 2007 - September 2007	Natural gas	3,060,000 MmBtu	$ (0.65)
January 2008 - December 2008	Natural gas	7,320,000 MmBtu	$ (0.6525)
January 2008 - December 2008	Natural gas	7,320,000 MmBtu	$ (0.635)
January 2008 - December 2008	Natural gas	7,320,000 MmBtu	$ (0.59)

These derivatives have not been designated as hedges.

The Company records all derivatives on the balance sheet at fair value. Changes in derivative fair values are recognized in earnings. Cash settlements and valuation gains and losses are included in loss (gain) on derivative contracts in the consolidated statements of operations. The following summarizes the cash settlements and valuation gains and losses for the years ended December 31, 2004, 2005 and 2006 (in thousands):

	2004	2005	2006 (Restated)
Realized loss (gain)	$ 2,681	$ 2,836	$ (14,169)
Unrealized loss (gain)	(1,803)	1,296	1,878
Loss (gain) on derivative contracts	$ 878	$ 4,132	$ (12,291)

13. Retirement Plan

The Company maintains a 401(k) retirement plan for its employees. Under the plan, eligible employees may elect to defer a portion of their earnings up to the maximum allowed by regulations promulgated by the Internal Revenue Service. Prior to August 2006, the Company made matching contributions equal to 50% on the first 6% of employee deferred wages (maximum 3% matching). The Company modified the 401(k) retirement plan in August 2006 to change the matching contributions to equal a match of 100% on the first 15% of employee deferred wages (maximum 15% matching). The plan was also modified to make the matching contributions payable in Company common stock. As of December 31, 2006, the Company has issued no shares related to the matching contribution. An accrued payable in the amount of $1.3 million is reflected in the consolidated balance sheet related to the matching contributions. For 2004, 2005 and 2006, retirement plan expense was approximately $0.2 million, $0.3 million and $1.5 million, respectively.

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Restated) (Continued)

14. Income Taxes

Significant components of the Company s deferred tax assets (liabilities) as of December 31 are as follows (in thousands):

	2005 (Restated)	2006 (Restated)
Deferred tax assets (liabilities):		
Current:		
Accrued liabilities	$ 953	$ 4,451
Other	370	1,864
Total current deferred tax assets	$ 1,323	$ 6,315
Noncurrent:		
Property, plant and equipment	$ (33,262)	$ (25,692)
Net operating loss carryforwards	19,130	
Other	385	770
Total noncurrent deferred tax liabilities	$ (13,747)	$ (24,922)

The provisions for income taxes for continuing operations consisted of the following components (in thousands):

	2004 (Restated)	2005 (Restated)	2006 (Restated)
Current:			
Federal	$	$ 508	$ 3,235
State			2,653
		508	5,888
Deferred:			
Federal	6,433	9,460	345
State			3
Total provision for income taxes	$ 6,433	$ 9,460	$ 348

A reconciliation of the provision for income taxes from continuing operations at the statutory federal tax rates to the Company s actual provision for income taxes is as follows for the year ended December 31 (in thousands):

	2004 (Restated)	2005 (Restated)	2006 (Restated)
Computed at federal statutory rates	$ 6,412	$ 9,543	$ 7,650
State taxes, net of federal benefit		390	1,724
Nondeductible expenses	21	35	84
Percentage depletion deduction			(3,488)
Change in rate			326
Other			(60)
Total provision for income taxes	$ 6,433	$ 9,968	$ 6,236

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Notes to Consolidated Financial Statements (Restated) (Continued)

As of December 31, 2006, the Company has fully utilized its net operating loss carryforwards during 2006. The Company, as of December 31, 2006, has approximately $770,000 of alternative minimum tax credits that do not expire.

15. Earnings Per Share

Basic earnings per share are computed using the weighted average number of common shares outstanding during the year. Diluted earnings per share are computed using the weighted average shares outstanding during the year, but also include the dilutive effect of awards of restricted stock. The following table summarizes the calculation of weighted average common shares outstanding used in the computation of diluted earnings per share, for the years ended December 31, 2004, 2005 and 2006 (in thousands).

	2004	2005	2006
Weighted average basic common shares outstanding	56,312	56,559	73,727
Effect of dilutive securities:			
Restricted stock		178	937
Weighted average diluted common and potential common shares outstanding	56,312	56,737	74,664

In computing diluted earnings per share, the Company evaluated the if-converted method. Under this method, the Company assumes the conversion of the outstanding redeemable convertible preferred stock to common stock and determines if this is more dilutive than including the preferred stock dividends (paid and unpaid) in the computation of income available to common stockholders. The Company determined the if-converted method is not more dilutive and has included preferred stock dividends in the determination of income available to common stockholders.

16. Commitments and Contingencies

The Company has obligations under noncancelable operating leases, primarily for the use of office space and equipment. Total rental expense under operating leases for the years ended December 31, 2004, 2005, and 2006, was approximately $0.8 million, $1.1 million and $1.1 million, respectively.

Future minimum lease payments under noncancelable operating leases (with initial lease terms in excess of one year) as of December 31, 2006, are as follows (in thousands):

Years Ended:	
2007	$ 2,180
2008	2,109
2009	1,337
2010	235

2011	235
Thereafter	384
	$ 6,480

Liquidated Damages Under Registration Rights Agreements

December 2005 Private Placement. In connection with the Company s private placement of common stock in December 2005, the Company entered into a registration rights agreement that requires the Company to use commercially reasonable efforts to maintain effectiveness of this registration statement or other shelf registration statements covering the shares sold in such private placement until December 21, 2007.

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Restated) (Continued)

Generally, if the Company fails to maintain an effective registration statement, the Company will be subject to liquidated damages payments equal to a percentage of the gross proceeds of the offering for each day that the Company is not in compliance. The payments increase every 90 days, up to a maximum as specified in the registration rights agreement as follows:

Non-Compliance Period			
1-90 Days	**91-180 Days**	**181-270 Days**	**270+ Days**
$1.2 million plus 0.5% per annum ($3,300 per day)	1.0% per annum ($6,600 per day)	1.5% per annum ($9,900 per day)	2.0% per annum ($13,200 per day)

November 2006 Private Placement. In connection with the Company s private placement of convertible preferred stock and common stock units, the Company entered into a registration rights agreement that requires the Company to use commercially reasonable efforts to maintain effectiveness of this registration statement or other shelf registration statements covering the shares sold in such private placement. In general, if the Company fails to meet these deadlines or maintain effectiveness, the Company will be subject to liquidated damage payments equal to a percentage of the purchase price of the securities sold in the November 2006 private placement.

During the first nine months following any failure to meet the deadlines described above, the payments will be equal to a percentage of the purchase price of $550 million on a per month basis until the default is cured. During the first month following a default, the payment shall be equal to 0.25% of the purchase price and shall increase by 0.25% per month to a maximum of 0.75%. If the default has not been cured within eight months, the payments will become equal to 2.0% per annum paid on a monthly basis until such default is cured.

March 2007 Private Placement. In connection with the Company s private placement of common stock in March 2007, the Company entered into a registration rights agreement that requires the Company to use commercially reasonable efforts to maintain effectiveness of this registration statement or other shelf registration statements covering the shares sold in such private placement. Generally, if the Company fails to maintain an effective registration statement, the Company will be subject to liquidated damages payments equal to a percentage of the gross proceeds of the offering for each day that we are not in compliance. The payments increase every 90 days, up to a maximum as specified in the registration rights agreement as follows:

Non-Compliance Period			
1-90 Days	**91-180 Days**	**181-270 Days**	**270+ Days**
$1.6 million plus 0.5% per annum ($4,400 per day)	1.0% per annum ($8,800 per day)	1.5% per annum ($13,200 per day)	2.0% per annum ($17,600 per day)

The Company has not recorded any amount related to liquidated damages and does not believe any amounts will be paid.

The Company is a defendant in certain lawsuits from time to time in the normal course of business. In management s opinion, the Company is not currently involved in any legal proceedings other than those specifically identified below, which individually or in the aggregate, could have a material effect on the financial condition, operations and/or cash flows of the Company.

Litigation with Conoco, Inc. In January 2007, the Company settled outstanding litigation with Conoco, Inc. for alleged unpaid overriding royalties on production by the Company on certain leases in Pecos County, Texas. Conoco, Inc. alleged that it was entitled to 12.5% of the proceeds from production and the Company alleged that Conoco, Inc., at most, was only entitled to a 5.0% overriding royalty on production. At December 31, 2006, as a result of the settlement whereby the Company will pay approximately $25.0 million plus interest to settle the outstanding litigation, the Company had approximately $25.0 million recorded as an

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Notes to Consolidated Financial Statements (Restated) (Continued)

accrual to reflect the settlement amount. Interest accrues from the settlement date in January 2007. The settlement payments are to be made in $5.0 million increments on April 1, 2007, July 1, 2008, July 1, 2009, July 1, 2010, and July 1, 2011. The settlement amount is included in accrued expenses ($5.0 million) and other long-term obligations ($20.0 million) in the Company s consolidated balance sheet as of December 31, 2006.

Roosevelt Litigation. On May 18, 2004, the Company commenced a civil action seeking declaratory judgment against Elliot Roosevelt, Jr., E.R. Family Limited Partnership and Ceres Resource Partners, L.P. in the District Court of Dallas County, Texas, 101st Judicial District, SandRidge Energy, Inc. and Riata Energy Piceance, LLC v. Elliot Roosevelt, Jr. et al, Cause No. 92.717-C. This suit sought a declaratory judgment relating to the rights of the parties in and to certain leases in a defined area of mutual interest in the Piceance Basin pursuant to an acquisition agreement entered into in 1989, including the Company s 41,454 gross (16,193 net) acreage position. The Company tried the case to a jury in July 2006. Before the case was submitted to the jury, the trial court granted Roosevelt a directed verdict stating that he owned a 25% deferred interest in the Company s acreage after project payout. The directed verdict is not likely to affect the Company s proved reserves of 11.7 Bcfe, because of the requirement that project payout be achieved before the deferred interest shares in revenue. Other issues of fact were submitted to the jury. The trial court recently entered a judgment favorable to Roosevelt. The Company has filed a motion to modify the judgment and for a new trial. Depending on the outcome of this motion, the Company expects to appeal, at a minimum, from the entry of the directed verdict. If the Company does not ultimately prevail, the deferred interest will reduce the Company s economic returns from the project, if project payout is achieved.

Yates Litigation. On April 29, 2005, Harvey E. Yates Company (Heyco), filed a trespass to try title suit against us in the District Court for Pecos County, Texas, 112th Judicial District, Harvey E. Yates Company v. Riata Energy, Inc., Cause No. 10376. In February 2006, additional parties joined the case as plaintiffs. The plaintiffs seeks title to a 44.57% working interest in a lease covering three sections of land and a 18.66% working interest in a lease covering 1.5 sections of land, each located in West Texas, as well as unspecified damages based on production attributable to these working interests. The plaintiffs claims stem from the alleged failure of the Company s predecessors in title to assign the disputed working interest in 1994. The Company believes that it has record title to the interest claimed by plaintiffs. Further, the Company believes the claims are barred by the four year statute of limitations, which the Company believes ran in 1998. If the plaintiffs prevail, any recovery would not be expected to have a material impact on proved reserves. The Company is currently in the preliminary stages of discovery.

The Company is subject to other claims in the ordinary course of business. However, the Company believes that the ultimate resolution of the above mentioned claims and other current legal proceedings will not have a material adverse effect on its results of operations or its financial condition.

17. Redeemable Convertible Preferred Stock

In November 2006, the Company sold 2,136,667 shares of redeemable convertible preferred stock as part of the NEG acquisition and received net proceeds from this sale of approximately $439.5 million after deducting offering expenses of approximately $9.3 million (See Note 3). Each holder of the redeemable convertible preferred stock is entitled to quarterly cash dividends at the annual rate of 7.75% of the accreted value of its redeemable convertible preferred stock. The accreted value is $210 per share as of December 31, 2006. The redeemable convertible preferred stock is mandatorily redeemable at a future determinable date and thus classified as mezzanine equity. Each share of convertible preferred stock is initially convertible into ten shares of common stock at the option of the holder, subject to certain anti-dilution adjustments.

On January 31, 2007, the Company s Board of Directors declared a dividend on the outstanding shares of redeemable convertible preferred stock. The dividend of $3.21 per share was paid in cash on February 15, 2007. The dividend covered the time period from November 21, 2006, when the shares were issued, through

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Restated) (Continued)

February 1, 2007. Approximately $3.8 million of dividends (pro rata amount from November 21, 2006 through December 31, 2006) has been included in the Company s earnings per share calculation in the accompanying consolidated statement of operations.

18. Stockholders Equity

On June 8, 2006, Tom L. Ward purchased approximately 29 million shares of common stock from the Company s founder, N. Malone Mitchell, 3rd, and other existing stockholders for $500 million at $17.25 per share. The purchase made Mr. Ward the Company s largest stockholder. He joined the Company as Chairman of the Board of Directors and Chief Executive Officer. Mr. Mitchell retained approximately 22 million shares and continues to serve as a member of the Board of Directors.

The following table presents information regarding SandRidge s common stock (in thousands):

	December 31,	
	2005	2006
Shares authorized	400,000	400,000
Shares outstanding at end of period	72,917	91,604
Shares held in treasury	1,415	1,444

The Company is authorized to issue 50,000,000 shares of preferred stock, no par value, of which no shares were outstanding as of December 31, 2005 and 2006. On September 23, 2005, 1,000 shares of preferred stock were converted into common stock.

Stock Split. On December 19, 2005, the Company entered into a 281.562 for 1 stock split. All references in the accompanying financial statements have been restated to reflect this stock split. The Company also authorized 400,000,000 shares of common stock with a par value of $0.001 per share.

Common Stock Issuance. In December 2005, the Company sold 12.5 million shares of common stock in a private placement and received net proceeds from this sale of approximately $173.1 million after deducting the initial purchasers discount of $16.8 million and offering expenses of approximately $1.2 million. Approximately $105.5 million of the proceeds of the offering were used to repay outstanding bank debt and finance the Company s December 2005 acquisitions (See Note 3).

In January 2006, the Company issued an additional 239,630 shares of common stock upon exercise by the underwriters of an over-allotment option. The Company issued these shares at a price of $15.00 per share after deducting the purchasers fee of $0.3 million. The Company received net proceeds from sale of approximately $3.3 million.

In November 2006, the Company sold 5.3 million common units (consisting of shares of common stock ($18.00 per share) and a warrant ($1.00 per share) to purchase convertible preferred stock upon the surrender of the common stock) as part of the NEG acquisition and received net proceeds from this sale of approximately $97.4 million after deducting the offering expenses of approximately $3.9 million (See Note 3).

Treasury Stock. Employees may elect to satisfy their tax obligations on the vesting of their restricted stock by having the Company make the required tax payments and withhold a number of vested shares having a value on the date of vesting equal to the tax obligation. As a result of such employee elections, during the year ended December 31, 2006 the Company withheld approximately 29,000 shares at a total value of $0.5 million, and those shares were accounted for as treasury stock. No shares were withheld in 2004 or 2005.

Restricted Stock. The Company issues restricted stock awards under incentive compensation plans which vest over specified periods of time (one, four and seven years). These shares of restricted common stock are subject to restriction on transfer and certain conditions to vesting.

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Notes to Consolidated Financial Statements (Restated) (Continued)

The Company granted restricted stock awards for approximately 1.6 million shares in December 2005. The stock awards were granted with one, four, and seven year vesting periods as follows: (i) 153,667 shares vest on the earlier of (x) December 31, 2006 or (y) the expiration of the lock-up agreement entered into by officers in connection with the Company s December 2005 private placement, (ii) 904,833 shares vest on the earlier of (x) June 30, 2010 or (y) the fourth anniversary of the completion of a registered initial public offering, and (iii) 493,667 shares vest on the earlier of (x) June 30, 2013 or (y) the seventh anniversary of the completion of a registered initial public offering.

In June 2006, the Company modified the vesting periods of the one year period and four year period restricted stock awards. One year restricted stock awards granted under the Riata 2005 Stock Plan were modified to vest on October 1, 2006, rather than December 31, 2006. Four year restricted stock awards granted under the Riata 2005 Stock Plan were modified to vest 25% each January 1, for four years, beginning January 1, 2007 rather than cliff vesting on June 30, 2010. The modification of the four year awards was completed pursuant to a plan that all restricted stock awards, in the future, will be four year terms vesting 25% each year. The Company recognized compensation cost related to this modification of $17,250 in June 2006.

Additionally, the Company modified the vesting period related to restricted shares awarded to certain executive officers, due to the executive officers resignations in June 2006 and August 2006. As part of the executive officers separation from the Company, the Board of Directors agreed to immediately vest all of the executive officers restricted stock. At the time of the modification and resignation in June 2006, one of the executive officers had 83,333 restricted stock awards (6,667 one year vesting, 66,666 four year vesting, 10,000 seven year vesting). The Company recognized compensation cost related to these shares of $1.3 million in the year ended December 31, 2006. At the time of the other modifications and resignations in August 2006, these executive officers had 138,667 restricted stock awards (13,667 one year vesting, 83,334 four year vesting, 41,666 seven year vesting). The Company recognized compensation cost related to these shares of $2.3 million in the year ended December 31, 2006.

In December 2006, the Company modified the vesting period related to restricted shares for employees due to these employees resignations from the Company in late December 2006. As part of these employees separation from the Company, the Board of Directors agreed to immediately vest the restricted stock for these employees that were previously due to vest on January 1, 2007. At the time of the modification and resignations of the employees in December 2006, the number of shares that were immediately vested was 39,960. The employees forfeited the remaining amounts of their unvested restricted shares. The Company recognized additional compensation cost in December 2006 for these shares of approximately $0.1 million due to the modification.

Restricted stock activity for the year ended December 31, 2006 was as follows (shares in thousands):

	Number of Shares	Weighted-Average Grant Date Fair Value
Unvested restricted shares outstanding at December 31, 2005	1,552	$ 15.00
Granted	240	18.49
Vested	(389)	17.22
Canceled	(466)	15.00

Unvested restricted shares outstanding at December 31, 2006	937	$ 15.88

For the year ended December 31, the Company recognized stock-based compensation expense related to restricted stock of approximately $8.8 million in 2006 and $0.5 million in 2005. Stock-based compensation expense is reflected in general and administrative expense in the consolidated statements of operations.

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Notes to Consolidated Financial Statements (Restated) (Continued)

As of December 31, 2006, there was approximately $11.7 million of unrecognized compensation cost related to unvested restricted stock awards which is expected to be recognized over a weighted average period of 2.6 years.

19. Related Party Transactions

During the ordinary course of business, the Company has transactions with certain stockholders and other related parties. These transactions primarily consist of purchases of drilling equipment and sales of oil field service supplies and gas sales. Following is a summary of significant transactions with such related parties as of and for the year ended December 31 (in thousands):

	2004	2005	2006
Sales to related parties	$ 306	$ 12,673	$ 14,102
Receivables from related parties for services rendered	$ 1,116	$ 5,376	$ 5,731
Payables to related parties for services rendered	$ 3,757	$ 78	$ 1,834
Purchases of services from related parties	$ 9,556	$ 37	$ 4,811

In September 2006, the Company entered into a new facilities lease with a member of its Board of Directors. The lease extends to August 2009 with annual future rental payments of $1.1 million in 2007 and 2008 and $0.7 million in 2009. The Company believes that the rent expense it must pay under this lease is at fair market rates. Rent expense in 2006 related to this facilities lease was $0.3 million.

20. Subsequent Events

On March 22, 2007 the Company entered into $1.0 billion in senior unsecured term loans (the Term Loans). The closing of the Term Loans was generally contingent upon closing the private placement of common equity described below. The Term Loans included both fixed rate term loans and floating rate term loans. Approximately $650.0 million was issued at a fixed rate of 8.625% with principal due on April 1, 2015 (the Fixed Rate Term Loans). Under the terms of the Fixed Rate Term Loans, interest is payable quarterly and during the first four years interest may be paid, at the Company s option, either entirely in cash or entirely with additional Fixed Rate Term Loans. If the Company elects to pay the interest due during any period in additional Fixed Rate Term Loans, the interest rate increases to 9.375% during such period. After April 1, 2011 the Fixed Rate Term Loans may be prepaid in whole or in part with prepayment penalties as follows (the prepayment penalty is multiplied by the principal amount prepaid):

Period	Prepayment Penalty
April 1, 2011 to March 31, 2012	4.313%
April 1, 2012 to March 31, 2013	2.156%

April 1, 2013 and thereafter

Approximately $350.0 million of the Term Loans was issued at a variable rate with interest payable quarterly and principal due on April 1, 2014 (the Variable Rate Term loans). The Variable Rate Term Loans bear interest, at the Company s option, at the British Bankers Association LIBOR rate plus 3.625% or the higher of (i) the federal funds rate, a defined, plus 3.125% or (ii) a Bank s prime rate plus 2.625%. After

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Notes to Consolidated Financial Statements (Restated) (Continued)

April 1, 2009 the Variable Rate Term Loans may be prepaid in whole or in part with a prepayment penalty as follows (the prepayment penalty is multiplied by the principal amount prepaid):

Period	Prepayment Penalty
April 1, 2009 to March 31, 2010	3.00%
April 1, 2010 to March 31, 2011	2.00%
April 1, 2011 to March 31, 2012	1.00%
April 1, 2012 and thereafter	

After one year from the closing date, the Company is required to offer to exchange the Term Loans for senior unsecured notes with registration rights. The senior unsecured notes will have identical terms and conditions as the Term Loans. If the Company is unable to or does not offer to exchange the Term Loans for senior unsecured notes with registration rights by the specified date, the interest rate on the Term Loans will increase by 0.25% every 90 days up to a maximum of 0.50%.

Debt covenants under the Term Loans are ordinary and customary and include limitations on the incurrence of indebtedness, payment of dividends, asset sales, certain asset purchases, transactions with related parties, and consolidation or merger agreements.

On March 20, 2007, the Company sold approximately 17.8 million shares of common stock for net proceeds of $320.0 million. The stock was sold in private sales to various investors including Tom Ward, the Company s Chairman of the Board of Directors and Chief Executive Officer, who invested $61.4 million in exchange for approximately 3.4 million shares of common stock.

A portion of the proceeds from the Term Loans was used to repay the Company s $850.0 million senior bridge facility.

21. Industry Segment Information

SandRidge has four business segments: Exploration and Production, Drilling and Oil Field Services, Midstream Gas Services, and Other representing its four main business units offering different products and services. The Exploration and Production segment is engaged in the development, acquisition and production of oil and natural gas properties. The Drilling and Oil Field Services segment is engaged in the land contract drilling of oil and natural gas wells, and the Midstream Gas Services segment is engaged in the purchasing, gathering, processing and treating of natural gas. The Other segment transports CO_2 to market for use by the Company and others in tertiary oil recovery operations and other miscellaneous operations.

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Notes to Consolidated Financial Statements (Restated) (Continued)

The accounting policies of the segments are the same as those described in the Summary of Significant Accounting Policies (Note 1). Management evaluates the performance of SandRidge s operating segments based on operating income, which is defined as operating revenues less operating expenses and depreciation, depletion and amortization. Summarized financial information concerning the Company s segments is shown in the following table (in thousands):

	2004 (Restated)	2005 (Restated)	2006 (Restated)
Revenues:			
Exploration and production	$ 39,226	$ 54,425	$ 106,990
Elimination of inter-segment revenue	1,662	374	577
Exploration and production, net of inter-segment revenue	37,564	54,051	106,413
Drilling and oil field services	59,179	109,766	211,055
Elimination of inter-segment revenue	19,968	29,615	72,398
Drilling and oil field services, net of inter-segment revenue	39,211	80,151	138,657
Midstream services	132,158	192,503	192,960
Elimination of inter-segment revenue	33,114	45,004	70,068
Midstream services, net of inter-segment revenues	99,044	147,499	122,892
Other	176	6,164	21,411
Elimination of inter-segment revenue		172	1,131
Other, net of inter-segment revenue	176	5,992	20,280
Total revenues	$ 175,995	$ 287,693	$ 388,242
Operating Income:			
Exploration and production	$ 14,000	$ 14,886	$ 17,069
Drilling and oil field services	4,206	18,295	32,946
Midstream gas services	2,636	4,096	3,528
Other	(92)	(3,224)	(16,562)
Total operating income	20,750	34,053	36,981
Interest expense, net	(1,622)	(5,071)	(15,795)
Other income (expense), net	(298)	(1,121)	671
Income before income taxes	$ 18,830	$ 27,861	$ 21,857

Identifiable Assets(1):			
Exploration and production	$ 125,745	$ 243,612	$ 2,091,459
Drilling and oil field services	35,807	100,995	175,169
Midstream gas services	25,208	33,845	75,606
Other	10,258	80,231	46,150
Total assets	$ 197,018	$ 458,683	$ 2,388,384

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SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Restated) (Continued)

	2004 (Restated)	2005 (Restated)	2006 (Restated)
Capital Expenditures:			
Exploration and production	$ 29,105	$ 61,227	$ 170,872
Drilling and oil field services	22,679	43,730	89,810
Midstream gas services	2,026	25,904	16,975
Other	4,116	3,735	28,884
Total capital expenditures	$ 57,926	$ 134,596	$ 306,541
Depreciation, Depletion and Amortization			
Exploration and production	$ 4,911	$ 8,796	$ 28,104
Drilling and oil field services	5,932	11,851	20,268
Midstream gas services	1,270	1,652	3,180
Other	561	1,907	4,074
Total depreciation, depletion and amortization	$ 12,674	$ 24,206	$ 55,626

(1) Identifiable assets are those used in SandRidge s operations in each industry segment. Corporate assets are principally cash and cash equivalents, corporate leasehold improvements, furniture and equipment.

22. Supplemental Information on Oil and Gas Producing Activities (Unaudited)

The Supplementary Information on Oil and Gas Producing Activities is presented as required by SFAS No. 69, Disclosures about Oil and Gas Producing Activities. The supplemental information includes capitalized costs related to oil and gas producing activities; costs incurred for the acquisition of oil and gas producing activities, exploration and development activities; and the results of operations from oil and gas producing activities. Supplemental information is also provided for per unit production costs; oil and gas production and average sales prices; the estimated quantities of proved oil and gas reserves; the standardized measure of discounted future net cash flows associated with proved oil and gas reserves; and a summary of the changes in the standardized measure of discounted future net cash flows associated with proved oil and gas reserves.

The Company s capitalized costs consisted of the following (in thousands):

Capitalized Costs Related to Oil and Gas Producing Activities

		December 31,	
Consolidated Companies(a)	**2004**	**2005**	**2006**

Oil and natural gas properties:			
Proved	$ 94,758	$ 160,789	$ 1,636,832
Unproved	744	33,974	282,374
Total oil and natural gas properties	95,502	194,763	1,919,206
Less accumulated depreciation and depletion	(26,034)	(35,029)	(60,752)
Net oil and natural gas properties capitalized costs	$ 69,468	$ 159,734	$ 1,858,454

(a) Amounts relate to SandRidge and Consolidated Subsidiaries. Includes capitalized asset retirement costs and associated accumulated depreciation.

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Notes to Consolidated Financial Statements (Restated) (Continued)

Costs Incurred in Property Acquisition, Exploration and Development Activities

	2004	2005	2006
Acquisitions of properties			
Proved	$	$ 14,554	$ 1,311,029
Unproved	1,631	21,085	268,839
Exploration	1,375	2,527	18,612
Development	27,357	60,364	115,153
Total cost incurred	$ 30,363	$ 98,530	$ 1,713,633

The Company s results of operations from oil and gas producing activities for each of the years 2004, 2005 and 2006 are shown in the following table (in thousands):

Results of Operations for Oil and Gas Producing Activities

	Consolidated Companies(a)
For the Year Ended December 31, 2004	
Revenues	$ 30,976
Expenses:	
Production costs	12,727
Depreciation, depletion and amortization expenses	4,770
Total expenses	17,497
Income before income taxes	13,479
Provision for income taxes	4,718
Results of operations for oil and gas producing activities	$ 8,761
For the Year Ended December 31, 2005	
Revenues	$ 48,405
Expenses:	
Production costs	19,352
Depreciation, depletion and amortization expenses	8,995
Total expenses	28,347

Income before income taxes		20,058
Provision for income taxes		7,020
Results of operations for oil and gas producing activities	$	13,038

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Notes to Consolidated Financial Statements (Restated) (Continued)

	Consolidated Companies(a)
For the Year Ended December 31, 2006	
Revenues	$ 101,252
Expenses:	
Production costs	39,363
Depreciation, depletion and amortization expenses	25,723
Total expenses	65,086
Income before income taxes	36,166
Provision for income taxes	10,850
Results of operations for oil and gas producing activities	$ 25,316

The table below represents the Company s estimate of proved crude oil and natural gas reserves attributable to the Company s net interest in oil and gas properties based upon the evaluation by the Company and its independent petroleum engineers of pertinent geological and engineering data in accordance with United States Securities and Exchange Commission regulations. Estimates of substantially all of the Company s proved reserves have been prepared by the team of independent reservoir engineers and geoscience professionals and are reviewed by members of the Company s senior management with professional training in petroleum engineering to ensure that the Company consistently applies rigorous professional standards and the reserve definitions prescribed by the United States Securities and Exchange Commission.

Netherland, Sewell & Associates, Inc., DeGolyer and MacNaughton and Harper & Associates, Inc., independent oil and gas consultants, have prepared the estimates of proved reserves of natural gas and crude oil attributable to several portions of the Company s net interest in oil and gas properties as of the end of one or more of 2004, 2005 and 2006. Netherland, Sewell & Associates, Inc., DeGolyer and MacNaughton and Harper & Associates, Inc. are independent petroleum engineers, geologists, geophysicists and petrophysicists and do not own an interest in us or our properties and are not employed on a contingent basis. Netherland, Sewell & Associates, Inc. prepared the estimates of proved reserves for all of our properties other than those held by PetroSource, which constitute approximately 97% of our total proved reserves as of December 31, 2006. DeGolyer and MacNaughton prepared the estimates of proved reserves for PetroSource, which constitute approximately 2% of our total proved reserves as of December 31, 2006. The small remaining portion of estimates of proved reserves were based on Company estimates.

The Company believes the geologic and engineering data examined provides reasonable assurance that the proved reserves are recoverable in future years from known reservoirs under existing economic and operating conditions. Estimates of proved reserves are subject to change, either positively or negatively, as additional information is available and contractual and economic conditions change.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, that is, prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. Proved developed reserves are the quantities of crude oil, natural gas liquids and natural gas expected to be recovered through existing investments in wells and field infrastructure under current operating conditions. Proved undeveloped reserves require additional investments in wells and related infrastructure in order to recover the production.

During 2006, the Company recognized additional reserves attributable to extensions and discoveries as a result of successful drilling in the Piñon Field. Drilling expenditures of $18.6 million resulted in the addition

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Notes to Consolidated Financial Statements (Restated) (Continued)

of 10.9 Bcfe of net proved developed reserves by extending the field boundaries as well as proving the producing capabilities of formations not previously captured as proved reserves. The remaining 83.1 Bcfe of net proved reserves for 2006 are proved undeveloped reserves associated with direct offsets to the 2006 drilling program extending the boundaries of the Piñon Field and zone identification. Changes in reserves associated with the development drilling have been accounted for in revisions of previous reserve estimates.

Reserve Quantity Information

	Consolidated Companies(a)	
	Crude Oil (MBbls)	Nat. Gas (MMcf)(b)
Proved developed and undeveloped reserves:		
As of December 31, 2003	649	121,256
Revisions of previous estimates	70	(18,955)
Extensions and discoveries		48,859
Production	(37)	(6,708)
As of December 31, 2004	682	144,452
Revisions of previous estimates	108	11,679
Acquisitions of new reserves	9,518	32,022
Extensions and discoveries	200	56,133
Production	(72)	(6,873)
As of December 31, 2005	10,436	237,413
Revisions of previous estimates	1,250	19,139
Acquisitions of new reserves	13,753	514,170
Extensions and discoveries	58	93,396
Production	(322)	(13,410)
As of December 31, 2006	25,175	850,708
Proved developed reserves:		
As of December 31, 2003	327	48,513
As of December 31, 2004	231	50,981
As of December 31, 2005	899	69,377
As of December 31, 2006	10,259	255,654

(a) Amounts relate to SandRidge and Consolidated Subsidiaries.

(b) Natural gas reserves are computed at 14.65 pounds per square inch absolute and 60 degrees Fahrenheit.

The standardized measure of discounted cash flows and summary of the changes in the standardized measure computation from year to year are prepared in accordance with SFAS No. 69. The assumptions that underlie the computation of the standardized measure of discounted cash flows may be summarized as follows:

the standardized measure includes the Company s estimate of proved crude oil, natural gas liquids and natural gas reserves and projected future production volumes based upon year-end economic conditions;

pricing is applied based upon year-end market prices adjusted for fixed or determinable contracts that are in existence at year-end;

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future development and production costs are determined based upon actual cost at year-end;

the standardized measure includes projections of future abandonment costs based upon actual costs at year-end; and

a discount factor of 10% per year is applied annually to the future net cash flows.

Standardized Measure of Discounted Future Net Cash Flows Related to Proved Oil and Gas Reserves

	Consolidated Companies(a) (In thousands)
As of December 31, 2004	
Future cash inflows from production	$ 843,647
Future production costs	(227,257)
Future development costs(b)	(77,588)
Future income tax expenses	(183,193)
Undiscounted future net cash flows	355,609
10% annual discount	(156,647)
Standardized measure of discounted future net cash flows	$ 198,962
As of December 31, 2005	
Future cash inflows from production	$ 2,558,668
Future production costs	(653,748)
Future development costs(b)	(296,489)
Future income tax expenses	(546,867)
Undiscounted future net cash flows	1,061,564
10% annual discount	(562,410)
Standardized measure of discounted future net cash flows	$ 499,154
As of December 31, 2006	
Future cash inflows from production	$ 5,901,660
Future production costs	(1,623,216)
Future development costs(b)	(931,947)
Future income tax expenses	(638,599)

Undiscounted future net cash flows		2,707,898
10% annual discount		(1,267,752)
Standardized measure of discounted future net cash flows	$	1,440,146

(a) Amounts relate to SandRidge and Consolidated Subsidiaries.

(b) Includes abandonment costs.

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Notes to Consolidated Financial Statements (Restated)   (Continued)

The following table represents the Company s estimate of changes in the standardized measure of discounted future net cash flows from proved reserves (in thousands):

Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Oil and Gas Reserves

	Consolidated Companies (a)
Present value as of December 31, 2003	$ 157,299
Changes during the year:	
Revenues less production and other costs	(18,249)
Net changes in prices, production and other costs	5,911
Development costs incurred	21,912
Net changes in future development costs	(16,360)
Extensions and discoveries	105,603
Revisions of previous quantity estimates	(38,234)
Accretion of discount	25,244
Net change in income taxes	(20,720)
Timing differences and other(b)	(23,444)
Net change for the year	41,663
Present value as of December 31, 2004	$ 198,962
Changes during the year:	
Revenues less production and other costs	(29,053)
Net changes in prices, production and other costs	225,227
Development costs incurred	56,368
Net changes in future development costs	(86,828)
Extensions and discoveries	96,514
Revisions of previous quantity estimates	47,501
Accretion of discount	28,981
Net change in income taxes	(155,250)
Purchases of reserves in-place	196,206
Timing differences and other(b)	(79,474)
Net change for the year	300,192

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SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Restated) (Continued)

	Consolidated Companies (a)
Present value as of December 31, 2005	$ 499,154
Revenues less production and other costs	(61,889)
Net changes in prices, production and other costs	(294,437)
Development costs incurred	75,323
Net changes in future development costs	(75,466)
Extensions and discoveries	126,061
Revisions of previous quantity estimates	54,313
Accretion of discount	73,643
Net change in income taxes	(36,962)
Purchases of reserves in-place	1,135,062
Timing differences and other(b)	(54,656)
Net change for the year	940,992
Present value as of December 31, 2006	$ 1,440,146

(a) Amounts relate to SandRidge and Consolidated Subsidiaries.

(b) The change in timing differences and other are related to revisions in the Company s estimated time of production and development.

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SandRidge Energy, Inc. and Subsidiaries

Condensed Consolidated Balance Sheets

	December 31, 2006	September 30, 2007
		(Unaudited)
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 38,948	$ 32,013
Accounts receivable, net:		
Trade	89,774	71,957
Related parties	5,731	16,727
Derivative contracts		27,903
Inventories	2,544	4,249
Deferred income taxes	6,315	
Other current assets	31,494	20,548
Total current assets	174,806	173,397
Oil and natural gas properties, using full cost method of accounting		
Proved	1,636,832	2,388,534
Unproved	282,374	247,757
Less: accumulated depreciation and depletion	(60,752)	(174,552)
	1,858,454	2,461,739
Other property, plant and equipment, net	276,264	427,756
Derivative contracts		4,139
Goodwill	26,198	27,076
Investments	3,584	6,983
Restricted deposits	33,189	39,851
Other assets	15,889	29,515
Total assets	$ 2,388,384	$ 3,170,456
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Current maturities of long-term debt	$ 26,201	$ 14,293
Accounts payable and accrued expenses:		
Trade	129,799	181,227
Related parties	1,834	3,182
Deferred income taxes		6,740
Derivative contracts	958	
Total current liabilities	158,792	205,442

Long-term debt	1,040,630	1,437,211
Derivative contracts	3,052	
Other long-term obligations	21,219	16,219
Asset retirement obligation	45,216	57,508
Deferred income taxes	24,922	32,992
Total liabilities	1,293,831	1,749,372
Commitments and contingencies (Note 12)		
Minority interest	5,092	5,605
Redeemable convertible preferred stock, $0.001 par value, 2,650 shares authorized; 2,137 and 2,184 shares issued and outstanding at December 31, 2006 and September 30, 2007, respectively	439,643	450,356
Stockholders equity:		
Preferred stock, no par; 50,000 shares authorized; no shares issued and outstanding in 2006 and 2007		
Common stock, $0.001 par value, 400,000 shares authorized; 93,048 issued and 91,604 outstanding at December 31, 2006 and 109,272 issued and 107,820 outstanding at September 30, 2007	92	108
Additional paid-in capital	574,868	889,211
Treasury stock, at cost	(17,835)	(18,496)
Retained earnings	92,693	94,300
Total stockholders equity	649,818	965,123
Total liabilities and stockholders equity	$ 2,388,384	$ 3,170,456

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

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SandRidge Energy, Inc. and Subsidiaries

Condensed Consolidated Statements of Operations

	Nine Months Ended September 30 2006	Nine Months Ended September 30 2007
	(Unaudited) (In thousands except per share amounts)	
Revenues:		
Natural gas and crude oil	$ 46,419	$ 319,556
Drilling and services	105,713	56,928
Midstream and marketing	91,218	71,131
Other	19,827	14,160
Total revenues	263,177	461,775
Expenses:		
Production	21,625	77,707
Production taxes	2,579	12,328
Drilling and services	72,670	30,935
Midstream and marketing	85,525	61,191
Depreciation, depletion and amortization natural gas and crude oil	13,932	115,876
Depreciation, depletion and amortization other	22,106	36,545
General and administrative	32,024	45,781
Gain on derivative contracts	(16,176)	(55,228)
Gain on sale of assets	(849)	(1,704)
Total expenses	233,436	323,431
Income from operations	29,741	138,344
Other income (expense):		
Interest income	448	4,201
Interest expense	(4,090)	(88,630)
Minority interest	(281)	(321)
Income from equity investments	40	3,399
Total other income (expense)	(3,883)	(81,351)
Income before income tax expense	25,858	56,993
Income tax expense	6,931	21,002
Net income	18,927	35,991
Preferred stock dividends and accretion		30,573
Income available to common stockholders	$ 18,927	$ 5,418

Basic and diluted income per share available to common stockholders	$	0.26	$	0.05
Weighted average number of shares outstanding:				
Basic		71,692		102,562
Diluted		72,633		103,778

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

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SandRidge Energy, Inc. and Subsidiaries

Condensed Consolidated Statement of Changes in Stockholders Equity

	Common Stock	Additional Paid-In Capital	Treasury Stock	Retained Earnings	Total
			(Unaudited) (In thousands)		
Balance, December 31, 2006	$ 92	$ 574,868	$ (17,835)	$ 92,693	$ 649,818
Stock offering, net of $1.4 million in offering costs	18	318,652			318,670
Conversion of common stock to redeemable convertible preferred stock	(1)	(9,650)			(9,651)
Accretion on redeemable convertible preferred stock				(1,062)	(1,062)
Purchase of treasury stock	(1)		(1,578)		(1,579)
Common stock issued under retirement plan		379	917		1,296
Stock-based compensation		4,962			4,962
Net income				35,991	35,991
Redeemable convertible preferred stock dividend				(33,322)	(33,322)
Balance, September 30, 2007	$ 108	$ 889,211	$ (18,496)	$ 94,300	$ 965,123

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

SandRidge Energy, Inc. and Subsidiaries

Condensed Consolidated Statements of Cash Flows

	Nine Months Ended September 30,	
	2006	2007
	(Unaudited) (In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 18,927	$ 35,991
Adjustments to reconcile net income to net cash provided by operating activities:		
Provision for doubtful accounts	2,458	
Depreciation, depletion and amortization	36,038	152,421
Debt issuance cost amortization		14,903
Deferred income taxes	2,662	20,004
Unrealized gain on derivatives	(2,007)	(36,052)
Gain on sale of assets	(849)	(1,704)
Interest income restricted deposits		(1,024)
Income from equity investments, net of distributions	(28)	(3,399)
Stock-based compensation	8,156	4,962
Minority interest	281	321
Changes in operating assets and liabilities	1,862	53,133
Net cash provided by operating activities	67,500	239,556
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures for property, plant and equipment	(181,231)	(895,160)
Acquisition of assets	(63,125)	(3,001)
Proceeds from sale of assets	19,742	6,458
Proceeds from sale of investment	2,373	
Contributions on equity investments	(3,388)	
Restricted deposits		(5,638)
Restricted cash	2,373	
Net cash used in investing activities	(223,256)	(897,341)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	295,215	1,262,769
Repayments of borrowings	(177,425)	(879,592)
Dividends paid preferred		(24,366)
Minority interest contributions (distributions)	(390)	192
Proceeds from issuance of common stock	3,343	319,966
Purchase of treasury shares		(1,579)
Debt issuance costs		(26,540)
Net cash provided by financing activities	120,743	650,850

NET DECREASE IN CASH AND CASH EQUIVALENTS		(35,013)		(6,935)
CASH AND CASH EQUIVALENTS, beginning of year		45,731		38,948
CASH AND CASH EQUIVALENTS, end of period	$	10,718	$	32,013
Supplemental Disclosure of Noncash Investing and Financing Activities:				
Insurance premiums financed	$		$	1,496
Accretion on redeemable convertible preferred stock	$		$	1,062
Common stock issued in connection with acquisitions	$	5,128	$	
Redeemable convertible preferred stock dividends, net of dividends paid	$		$	8,956
Property, plant and equipment addition due to settlement	$		$	4,500

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

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SandRidge Energy, Inc. and Subsidiaries

Notes to Condensed Consolidated Financial Statements

1. Basis of Presentation

Nature of Business. SandRidge Energy, Inc. and its subsidiaries (collectively, the Company , SandRidge , we , us , or our) is an oil and gas company with its principal focus on exploration, development and production related to oil and gas activities. SandRidge also owns and operates drilling rigs and provides related oil field services, midstream gas services operations, and CO_2 and tertiary oil recovery operations. SandRidge s primary exploration, development and production areas are concentrated in West Texas. The Company also operates significant interests in the Cotton Valley Trend in East Texas and Gulf Coast area.

On November 21, 2006, the Company acquired all of the outstanding membership interests of NEG Oil & Gas LLC (NEG).

Interim Financial Statements. The accompanying condensed consolidated balance sheet as of December 31, 2006 has been derived from our audited financial statements contained in the Company s Registration Statement on Form S-1/A filed October 23, 2007 (the Registration Statement). The unaudited interim condensed consolidated financial statements of SandRidge and its subsidiaries have been prepared by the Company in accordance with the accounting policies stated in the audited consolidated financial statements contained in the Company s S-1/A filed October 23, 2007 pursuant to the rules and regulations of the Securities and Exchange Commission (SEC). Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) have been condensed or omitted, although we believe that the disclosures contained herein are adequate to make the information presented not misleading. In the opinion of management, all adjustments (consisting only of normal recurring adjustments) necessary for a fair presentation in accordance with GAAP have been included in these unaudited interim condensed consolidated financial statements. These condensed financial statements should be read in conjunction with the financial statements and notes thereto included in the Registration Statement.

2. Significant Accounting Policies

For a description of the Company s accounting policies, refer to Note 1 of the 2006 consolidated financial statements included in the Company s Registration Statement, as well as Note 10 herein.

Reclassifications. Certain reclassifications have been made in prior period financial statements to conform with current period presentation.

Change in Method of Accounting for Oil and Gas Operations. In the fourth quarter of 2006, the Company changed from the successful efforts method to the full cost method of accounting for its oil and gas operations. Prior period financial statements presented herein have been restated to reflect the change.

SandRidge s financial results have been retroactively restated to reflect the conversion to the full cost method. As prescribed by full cost accounting rules, all costs associated with property acquisition, exploration, and development activities are capitalized. Exploration and development costs include dry hole costs, geological and geophysical costs, direct overhead related to exploration and development activities and other costs incurred for the purpose of finding oil and gas reserves.

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SandRidge Energy, Inc. and Subsidiaries

Notes to Condensed Consolidated Financial Statements (Continued)

A comparison of the Company s previously presented income tax expense, net income, and earnings per share under the successful efforts method of accounting to its results of operations disclosed herein are as follows (in thousands, except per share amounts):

	Nine Months Ended September 30, 2006 (As originally presented)	Nine Months Ended September 30, 2006 (As restated)
Income tax expense	$ 8,998	$ 6,931
Net income	$ 15,175	$ 18,927
Basic earnings per share	$ 0.21	$ 0.26
Diluted earnings per share	$ 0.21	$ 0.26

Oil and Natural Gas Operations. The Company uses the full cost method to account for its natural gas and oil properties. Under full cost accounting, all costs directly associated with the acquisition, exploration and development of natural gas and oil reserves are capitalized into a full cost pool. These capitalized costs include costs of all unproved properties, internal costs directly related to the Company s acquisition, exploration and development activities and capitalized interest. These costs are amortized using a unit-of-production method. Under this method, the provision for depreciation, depletion and amortization is computed at the end of each quarter by multiplying total production for such quarter by a depletion rate. The depletion rate is determined by dividing the total unamortized cost base by net equivalent proved reserves at the beginning of the quarter.

Recent Accounting Pronouncements. In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements, which establishes a formal framework for measuring fair values of assets and liabilities in financial statements that are already required by GAAP to be measured at fair value. SFAS No. 157 clarifies guidance in FASB Concepts Statement (CON) No. 7 which discusses present value techniques in measuring fair value. Additional disclosures are also required for transactions measured at fair value. No new fair value measurements are prescribed, and SFAS No. 157 is intended to codify the several definitions of fair value included in various accounting standards. However, the application of this Statement may change current practices for certain companies. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. The Company is currently evaluating the impact of adopting SFAS No. 157 on the financial statements.

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 (SFAS No. 159), which permits an entity to choose to measure certain financial assets and liabilities at fair value. SFAS No. 159 also revises provisions of SFAS No. 115 that apply to available-for-sale and trading securities. This statement is effective for fiscal years beginning after

November 15, 2007. The Company has not yet evaluated the potential impact of this standard.

3. Acquisitions and Dispositions

On March 15, 2006, the Company acquired from an executive officer and director, an additional 12.5% interest in PetroSource Energy Company, a consolidated subsidiary. The acquisition consisted of the extinguishment of subordinated debt of approximately $1.0 million and a $4.5 million cash payment for the ownership interest acquired for a total acquisition price of approximately $5.5 million.

On May 1, 2006, the Company purchased certain leases in developed and undeveloped properties from an oil and gas company. The purchase price was approximately $40.9 million in cash. The cash consideration was paid in July 2006.

SandRidge Energy, Inc. and Subsidiaries

Notes to Condensed Consolidated Financial Statements (Continued)

On May 26, 2006, the Company purchased several oil and natural gas properties from an oil and gas company. The purchase price was approximately $12.9 million, comprised of $8.2 million in cash, and 251,351 shares of SandRidge Energy, Inc. common stock (valued at $4.7 million). The cash and equity consideration was paid in July 2006.

On June 7, 2006, the Company acquired the remaining 1% interest in PetroSource Energy Company, a consolidated subsidiary, from an oil and gas company. The purchase price was 27,749 shares of SandRidge Energy, Inc. common stock (valued at $0.5 million). As a result of this acquisition, the Company became a 100% owner of PetroSource Energy Company.

In July 2006, the Company sold leaseholds and lease and well equipment for $16.0 million. The book basis of the assets at the time of the sale transaction was $3.7 million resulting in a gain of $12.3 million. The sale was accounted for as an adjustment to the full cost pool, with no gain recognized.

4. Property, Plant and Equipment

Property, plant and equipment consists of the following (in thousands):

	December 31, 2006	September 30, 2007
Oil and natural gas properties:		
Proved	$ 1,636,832	$ 2,388,534
Unproved	282,374	247,757
Total oil and natural gas properties	1,919,206	2,636,291
Less accumulated depreciation and depletion	(60,752)	(174,552)
Net oil and natural gas properties capitalized costs	1,858,454	2,461,739
Land	738	1,344
Non oil and gas equipment	337,294	491,000
Buildings and structures	6,564	37,725
Total	344,596	530,069
Less accumulated depreciation, depletion and amortization	(68,332)	(102,313)
Net capitalized costs	276,264	427,756
Total property, plant and equipment	$ 2,134,718	$ 2,889,495

The amount of capitalized interest in the nine months ended September 30, 2006 and 2007 was approximately $1.0 million and $1.5 million, respectively, and is included in the above non oil and gas equipment balance.

On July 11, 2007, the Company purchased property to serve as its future corporate headquarters. The 3.51-acre site contains four buildings and is located in downtown Oklahoma City, Oklahoma. The purchase price of the property was approximately $25 million in cash plus the assumption of an obligation to indemnify the sellers in connection with pending litigation involving the property. Payment of the purchase price was funded through a draw on the Company s senior credit facility. The related litigation was settled subsequent to September 30, 2007, resulting in an additional cost to the Company of $4.5 million which was treated as an adjustment to the purchase price of the property. For additional discussion of this settlement, refer to Note 17 herein.

SandRidge Energy, Inc. and Subsidiaries

Notes to Condensed Consolidated Financial Statements (Continued)

5. Goodwill

The change in the carrying amount of goodwill from December 31, 2006 to September 30, 2007 was as follows (in thousands):

Balance at December 31, 2006	$ 26,198
Adjustments	878
Balance at September 30, 2007	$ 27,076

The adjustments made in the nine months ended September 30, 2007 related to the preliminary purchase allocation in connection with the NEG acquisition in November 2006. The Company has assigned all of the NEG goodwill to the Exploration and Production segment.

6. Asset Retirement Obligation

A reconciliation of the beginning and ending aggregate carrying amounts of the asset retirement obligations for the period of December 31, 2006 to September 30, 2007 is as follows (in thousands):

Asset retirement obligation, December 31, 2006	$ 45,216
Liability incurred upon acquiring and drilling wells	1,688
Revisions in estimated cash flows	7,747
Liability settled in current period	(9)
Accretion of discount expense	2,866
Asset retirement obligation, September 30, 2007	$ 57,508

7. Long-Term Debt

Long-term obligations consist of the following (in thousands):

	December 31, 2006	September 30, 2007
Senior credit facility	$ 140,000	$ 400,000
Senior bridge facility	850,000	
Senior term loan		1,000,000
Other notes payable:		
Drilling rig fleet and related oil field services equipment	61,105	51,261

Sagebrush		4,000		
Insurance financing		7,240		199
Other equipment and vehicles		4,486		44
Total debt		1,066,831		1,451,504
Less: Current maturities of long-term debt		26,201		14,293
Long-term debt	$	1,040,630	$	1,437,211

Senior Credit Facility. On November 21, 2006, the Company entered into a $750 million senior secured revolving credit facility (the senior credit facility). The senior credit facility matures on November 21, 2011.

The proceeds of the senior credit facility were used to (i) partially finance the NEG acquisition, (ii) refinance the existing senior secured revolving credit facility and NEG s existing credit facility**,** and (iii) pay fees and expenses related to the NEG acquisition and the existing credit facility. Future borrowings under the

SandRidge Energy, Inc. and Subsidiaries

Notes to Condensed Consolidated Financial Statements (Continued)

senior credit facility will be available for capital expenditures, working capital and general corporate purposes and to finance permitted acquisitions of oil and gas properties and other assets related to the exploration, production and development of oil and gas properties. The senior credit facility will be available to be drawn on and repaid without restriction so long as the Company is in compliance with its terms, including certain financial covenants.

The senior credit facility contains various covenants that limit the Company and certain of its subsidiaries ability to grant certain liens; make certain loans and investments; make distributions; redeem stock; redeem or prepay debt; merge or consolidate with or into a third party; or engage in certain asset dispositions, including a sale of all or substantially all of the Company s assets. Additionally, the senior credit facility limits the Company and certain of its subsidiaries ability to incur additional indebtedness with certain exceptions, including under the senior unsecured bridge facility (as discussed below) which was repaid in full during March 2007.

The senior credit facility also contains financial covenants, including maintenance of agreed upon levels for the ratio of (i) total funded debt to EBITDAX (as defined in the senior credit facility), (ii) EBITDAX to interest expense plus current maturities of long-term debt, and (iii) current ratio. The Company was in compliance with these financial covenants as of September 30, 2007.

The obligations under the senior credit facility are secured by first priority liens on all shares of capital stock of each of the Company s present and future subsidiaries; all intercompany debt of the Company and its subsidiaries; and substantially all of the Company assets and the assets of its guarantor subsidiaries, including proven oil and gas reserves representing at least 80% of the present discounted value (as defined in the senior credit facility) of proven oil and gas reserves reviewed in determining the borrowing base for the senior credit facility. Additionally, the obligations under the senior credit facility will be guaranteed by certain Company subsidiaries.

At the Company s election, interest under the senior credit facility is determined by reference to (i) the British Bankers Association LIBOR rate, or LIBOR, plus an applicable margin between 1.25% and 2.00% per annum or (ii) the higher of the federal funds rate plus 0.5% or the prime rate plus, in either case, an applicable margin between 0.25% and 1.00% per annum. Interest will be payable quarterly for prime rate loans and at the applicable maturity date for LIBOR loans, except that if the interest period for a LIBOR loan is six months, interest will be paid at the end of each three-month period. The average interest rates paid on amounts outstanding under our senior credit facility for the three and nine month periods ended September 30, 2007 were 7.08% and 7.62%, respectively.

The borrowing base of proved reserves was initially set at $300.0 million. As of December 31, 2006, the Company had $140.0 million of outstanding indebtedness on the senior credit facility. Proceeds from the Company s sale of common stock on March 20, 2007, as described in Note 14, were used to repay outstanding borrowings under the Company s senior credit facility.

The borrowing base was increased to $400 million on May 2, 2007, and to $700 million on September 14, 2007. At September 30, 2007, the Company had $400 million in outstanding indebtedness under this facility. The Company repaid all amounts outstanding under this facility subsequent to September 30, 2007. See Note 17 for further discussion.

Senior Bridge Facility. On November 21, 2006, the Company also entered into an $850.0 million senior unsecured bridge facility (the senior bridge facility), which was repaid in March 2007. The Company expensed remaining unamortized debt issuance costs related to the senior bridge facility of approximately $12.5 million to interest expense in March 2007.

Together with borrowings under the senior credit facility, the proceeds from the senior bridge facility were used to (i) partially finance the NEG acquisition, (ii) refinance existing senior secured revolving credit

SandRidge Energy, Inc. and Subsidiaries

Notes to Condensed Consolidated Financial Statements (Continued)

facility and NEG s existing credit facility**,** and (iii) pay fees and expenses related to the NEG acquisition and the existing credit facility.

Senior Term Loans. On March 22, 2007 the Company entered into $1.0 billion in senior unsecured term loans (the senior term loans). The closing of the senior term loans was generally contingent upon closing the private placement of common equity as described in Note 14. The senior term loans include both floating rate term loans and fixed rate term loans. Approximately $350.0 million of the senior term loans was issued at a variable rate with interest payable quarterly and principal due on April 1, 2014 (the variable rate term loans). The variable rate term loans bear interest, at the Company s option, at the British Bankers Association LIBOR rate plus 3.625% or the higher of (i) the federal funds rate, as defined, plus 3.125% or (ii) a Bank s prime rate plus 2.625%. After April 1, 2009 the variable rate term loans may be prepaid in whole or in part with certain prepayment penalties. The average interest rates paid on amounts outstanding under our variable term loans for the three and nine month periods ended September 30, 2007 were 8.99% and 8.98%, respectively.

Approximately $650.0 million was issued at a fixed rate of 8.625% with the principal due on April 1, 2015 (the fixed rate term loans). Under the terms of the fixed rate term loans, interest is payable quarterly and during the first four years interest may be paid, at the Company s option, either entirely in cash or entirely with additional fixed rate term loans. If the Company elects to pay the interest due during any period in additional fixed rate term loans, the interest rate increases to 9.375% during such period. After April 1, 2011 the fixed rate term loans may be prepaid in whole or in part with certain prepayment penalties.

After March 22, 2008, the Company is required to offer to exchange the senior term loans for senior unsecured notes with registration rights and with identical terms and conditions as the term loans. If the Company is unable or does not offer to exchange the senior term loans for senior unsecured notes with registration rights by April 30, 2008, the interest rate on the senior term loans will increase by 0.25% every 90 days up to a maximum of 0.50%.

Debt covenants under the senior term loans include financial covenants similar to those of the senior credit facility and include limitations on the incurrence of indebtedness, payment of dividends, asset sales, certain asset purchases, transactions with related parties, and consolidation or merger agreements. The Company incurred $26.1 million of debt issuance costs in connection with the senior term loans. These costs are included in other assets and amortized over the term of the senior term loans. A portion of the proceeds from the senior term loans was used to repay the Company s $850.0 million senior bridge facility.

For the nine months ended September 30, interest payments, net of amounts capitalized were approximately $4.6 million in 2006 and $59.5 million in 2007.

8. Other Long-Term Obligations

The Company has recorded a long-term obligation for amounts to be paid under a settlement agreement with Conoco, Inc. (Conoco). During January 2007, the Company agreed to pay approximately $25.0 million plus interest to Conoco to settle outstanding litigation. Under this agreement, payments are to be made in $5.0 million increments on April 1, 2007, July 1, 2008, July 1, 2009, July 1, 2010, and July 1, 2011. On March 30, 2007, the Company made the first $5.0 million settlement payment plus accrued interest. The $5.0 million payment to be made on July 1, 2008 has been included in accounts payable-trade in the accompanying condensed consolidated balance sheets as of September 30,

2007. Unpaid settlement amounts of approximately $20.0 million and $15.0 million have been included in other long-term obligations in the accompanying condensed consolidated balance sheets as of December 31, 2006 and September 30, 2007, respectively.

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SandRidge Energy, Inc. and Subsidiaries

Notes to Condensed Consolidated Financial Statements (Continued)

9. Derivatives

The Company has entered into various derivative contracts including collars, fixed price swaps, and basis swaps with counterparties. The contracts expire on various dates through December 31, 2009.

At September 30, 2007, the Company s open commodity derivative contracts consisted of the following:

Period	Commodity	Notional	Weighted Avg. Fix Price
Fixed price swaps:			
April 2007 - October 2007	Natural gas	4,280,000 MmBtu	$7.02
April 2007 - October 2007	Natural gas	4,280,000 MmBtu	$7.50
September 2007 - December 2007	Natural gas	1,220,000 MmBtu	$8.88
October 2007 - December 2007	Natural gas	920,000 MmBtu	$7.60
October 2007 - December 2007	Natural gas	920,000 MmBtu	$7.82
October 2007 - December 2007	Natural gas	920,000 MmBtu	$8.00
October 2007 - December 2007	Natural gas	920,000 MmBtu	$8.04
October 2007 - December 2007	Natural gas	920,000 MmBtu	$8.77
October 2007 - December 2007	Natural gas	920,000 MmBtu	$9.04
November 2007 - June 2008	Natural gas	4,860,000 MmBtu	$8.05
November 2007 - June 2008	Natural gas	9,720,000 MmBtu	$8.20
November 2007 - March 2008	Natural gas	1,520,000 MmBtu	$8.51
January 2008 - June 2008	Natural gas	3,640,000 MmBtu	$7.99
January 2008 - June 2008	Natural gas	3,640,000 MmBtu	$7.99
January 2008 - December 2008	Natural gas	3,660,000 MmBtu	$8.23
January 2008 - December 2008	Natural gas	3,660,000 MmBtu	$8.48
January 2008 - December 2008	Natural gas	3,660,000 MmBtu	$9.00
May 2008 - August 2008	Natural gas	2,460,000 MmBtu	$8.38
July 2008 - September 2008	Natural gas	920,000 MmBtu	$8.23
July 2008 - December 2008	Natural gas	1,840,000 MmBtu	$8.31
Collars:			
January 2007 - December 2007	Crude oil	60,000 Bbls	$50.00 - $84.50
January 2008 - June 2008	Crude oil	42,000 Bbls	$50.00 - $83.35
July 2008 - December 2008	Crude oil	54,000 Bbls	$50.00 - $82.60
Waha basis swaps:			
January 2007 - December 2007	Natural gas	7,300,000 MmBtu	$(0.5925)
January 2007 - December 2007	Natural gas	14,600,000 MmBtu	$(0.70)
April 2007 - October 2007	Natural gas	4,280,000 MmBtu	$(0.530)
January 2008 - December 2008	Natural gas	10,980,000 MmBtu	$(0.57)
January 2008 - December 2008	Natural gas	7,320,000 MmBtu	$(0.585)
January 2008 - December 2008	Natural gas	7,320,000 MmBtu	$(0.59)
January 2008 - December 2008	Natural gas	3,660,000 MmBtu	$(0.595)

January 2008 - December 2008	Natural gas	3,660,000 MmBtu	$(0.625)
January 2008 - December 2008	Natural gas	7,320,000 MmBtu	$(0.635)
January 2008 - December 2008	Natural gas	7,320,000 MmBtu	$(0.6525)
May 2008 - August 2008	Natural gas	2,460,000 MmBtu	$(0.45)
January 2009 - December 2009	Natural gas	3,650,000 MmBtu	$(0.47)
January 2009 - December 2009	Natural gas	3,650,000 MmBtu	$(0.49)
January 2009 - December 2009	Natural gas	3,650,000 MmBtu	$(0.4975)

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SandRidge Energy, Inc. and Subsidiaries

Notes to Condensed Consolidated Financial Statements (Continued)

These derivatives have not been designated as hedges and the Company records all derivatives on the balance sheet at fair value. Changes in derivative fair values are recognized in earnings. Cash settlements and valuation gains and losses are included in gain on derivative contracts in the condensed consolidated statements of operations. The following summarizes the cash settlements and valuation gains and losses for the nine month periods ended September 30, 2006 and 2007 (in thousands):

	Nine Months Ended September 30,	
	2006	2007
Realized gain	$ (14,169)	$ (19,176)
Unrealized loss (gain)	(2,007)	(36,052)
Gain on derivative contracts	$ (16,176)	$ (55,228)

10. Income Taxes

In accordance with applicable generally accepted accounting principles, the Company estimates for each interim reporting period the effective tax rate expected for the full fiscal year and uses that estimated rate in providing income taxes on a current year-to-date basis.

On January 1, 2007, the Company adopted the provisions of FASB Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes. The Company has determined that no uncertain tax positions exist where the Company would be required to make additional tax payments. As a result, the Company has not recorded any additional liabilities for any unrecognized tax benefits as of September 30, 2007. The Company and its subsidiaries file income tax returns in the U.S. federal and various state jurisdictions. Tax years 1994 to present remain open for the majority of taxing authorities. The Company s accounting policy is to recognize penalties and interest related to unrecognized tax benefits as income tax expense. The Company does not have an accrued liability for the payment of penalties and interest at September 30, 2007.

For the nine months ended September 30, income tax payments were approximately $1.9 million in 2006 and $2.7 million in 2007.

11. Earnings Per Share

Basic earnings per share are computed using the weighted average number of common shares outstanding during the period. Diluted earnings per share are computed using the weighted average shares outstanding during the year, but also include the dilutive effect of awards of restricted stock. The following table summarizes the calculation of weighted average common shares outstanding used in the computation of diluted earnings per share, for the nine month periods ended September 30, 2006 and 2007 (in thousands):

	Nine Months Ended September 30,	
	2006	2007
Weighted average basic common shares outstanding	71,692	102,562
Effect of dilutive securities:		
Restricted stock	941	1,216
Weighted average diluted common and potential common shares outstanding	72,633	103,778

In computing diluted earnings per share, the Company evaluated the if-converted method. Under this method, the Company assumes the conversion of the outstanding redeemable convertible preferred stock to common stock and determines if this is more dilutive than including the preferred stock dividends (paid and unpaid) in the computation of income available to common stockholders. The Company determined the

SandRidge Energy, Inc. and Subsidiaries

Notes to Condensed Consolidated Financial Statements (Continued)

if-converted method is not more dilutive and has included preferred stock dividends in the determination of income available to common stockholders.

12. Commitments and Contingencies

The Company is a defendant in certain lawsuits from time to time in the normal course of business. In management s opinion, the Company is not currently involved in any legal proceedings other than those specifically identified below, which individually or in the aggregate, could have a material effect on the financial condition, operations and/or cash flows of the Company.

Roosevelt Litigation. On May 18, 2004, the Company commenced a civil action seeking declaratory judgment against Elliot Roosevelt, Jr., E.R. Family Limited Partnership and Ceres Resource Partners, L.P. in the District Court of Dallas County, Texas, 101st Judicial District, SandRidge Energy, Inc. and Riata Energy Piceance, LLC v. Elliot Roosevelt, Jr. et al, Cause No. 92.717-C. This suit sought a declaratory judgment relating to the rights of the parties in and to certain leases in a defined area of mutual interest in the Piceance Basin pursuant to an acquisition agreement entered into in 1989, including the Company s 41,454 gross (16,193 net) acreage position. The Company tried the case to a jury in July 2006. Before the case was submitted to the jury, the trial court granted Roosevelt a directed verdict stating that he owned a 25% deferred interest in the Company s acreage after project payout. The directed verdict is not likely to affect the Company s proved reserves of 11.7 Bcfe, because of the requirement that project payout be achieved before the deferred interest shares in revenue. Other issues of fact were submitted to the jury. The trial court recently entered a judgment favorable to Roosevelt. The Company has filed a motion to modify the judgment and for a new trial. Depending on the outcome of this motion, the Company expects to appeal, at a minimum, from the entry of the directed verdict. If the Company does not ultimately prevail, the deferred interest will reduce the Company s economic returns from the project, if project payout is achieved.

The Company is subject to other claims in the ordinary course of business. However, the Company believes that the ultimate resolution of the above mentioned claims and other current legal proceedings will not have a material adverse effect on its results of operations, financial condition, or cash flows.

13. Redeemable Convertible Preferred Stock

In November 2006, the Company sold 2,136,667 shares of redeemable convertible preferred stock as part of the NEG acquisition and received net proceeds from this sale of approximately $439.5 million after deducting offering expenses of approximately $9.3 million. Each holder of the redeemable convertible preferred stock is entitled to quarterly cash dividends at the annual rate of 7.75% of the accreted value of its redeemable convertible preferred stock. The accreted value is $210 per share as of September 30, 2007. Each share of convertible preferred stock is initially convertible into ten shares of common stock at the option of the holder, subject to certain anti-dilution adjustments.

On January 31, 2007, the Company s Board of Directors declared a dividend on the outstanding shares of redeemable convertible preferred stock. The dividend of $3.21 per share was paid in cash on February 15, 2007. The dividend covered the time period from November 21, 2006, when the shares were issued, through February 1, 2007.

On March 30, 2007, certain holders of the Company s common units (consisting of shares of common stock and a warrant to purchase redeemable convertible preferred stock upon the surrender of common stock) exercised warrants to purchase redeemable convertible preferred stock. The holders converted 526,316 shares of common stock into 47,619 shares of redeemable convertible preferred stock.

On May 8, 2007, the Company s Board of Directors declared a dividend on the outstanding shares of redeemable convertible preferred stock. The dividend of $3.97 per share was paid in cash on May 15, 2007. The dividend covered the time period from February 2, 2007 through May 1, 2007.

SandRidge Energy, Inc. and Subsidiaries

Notes to Condensed Consolidated Financial Statements (Continued)

On June 8, 2007, the Company s Board of Directors declared a dividend on the outstanding shares of redeemable convertible preferred stock. The dividend of $4.10 per share was paid in cash on August 15, 2007. The dividend covered the time period from May 2, 2007 through August 1, 2007.

On September 24, 2007, the Company s Board of Directors declared a dividend on the outstanding shares of redeemable convertible preferred stock. The dividend of $4.10 per share was paid in cash on November 15, 2007. The dividend covers the time period from August 2, 2007 to November 1, 2007.

Approximately $29.5 million in paid and unpaid dividends have been included in the Company s earnings per share calculations for the nine month period ended September 30, 2007, as presented in the accompanying condensed consolidated statements of operations.

14. Stockholders Equity

The following table presents information regarding SandRidge s common stock (in thousands):

	December 31, 2006	September 30, 2007
Shares authorized	400,000	400,000
Shares outstanding at end of period	91,604	107,820
Shares held in treasury	1,444	1,452

The Company is authorized to issue 50,000,000 shares of preferred stock, no par value, of which no shares were outstanding as of December 31, 2006 and September 30, 2007.

Common Stock Issuance. In March 2007, the Company sold approximately 17.8 million shares of common stock for net proceeds of $318.7 million after deducting offering expenses of approximately $1.4 million. The stock was sold in private sales to various investors including Tom L. Ward, the Company s Chairman of the Board of Directors and Chief Executive Officer, who invested $61.4 million in exchange for approximately 3.4 million shares of common stock.

Treasury Stock. The Company makes required tax payments on behalf of employees as their stock awards vest and then withholds a number of vested shares having a value on the date of vesting equal to the tax obligation. As a result of such transactions, the Company withheld 41,095 shares at a total value of $0.7 million during the nine month period ended September 30, 2007. These shares were accounted for as treasury stock.

On June 28, 2007, the Company purchased 39,844 shares of its common stock into treasury through an open market repurchase program in order to fund a portion of its 401(K) matching obligation as described below. Cash consideration for these shares of approximately $0.8 million was paid in July 2007.

On June 29, 2007, the Company transferred 72,044 shares of its treasury stock to the Company s 401k Plan brokerage account. The transfer was made in order to satisfy the Company s $1.3 million accrued payable to match employee contributions made to the plan during 2006. Historical cost of the shares transferred totaled approximately $0.9 million, resulting in an increase to the Company s additional paid-in capital of approximately $0.4 million.

Restricted Stock. The Company issues restricted stock awards under incentive compensation plans which vest over specified periods of time. Awards issued prior to 2006 vest over periods of one, four, or seven years. All awards issued during and after 2006 have four year vesting periods. These shares of restricted common stock are subject to restriction on transfer and certain conditions to vesting.

For the nine months ended September 30, the Company recognized stock-based compensation expense related to restricted stock of approximately $8.2 million in 2006 and $5.0 million in 2007. Stock-based compensation expense is reflected in general and administrative expense in the condensed consolidated statements of operations.

SandRidge Energy, Inc. and Subsidiaries

Notes to Condensed Consolidated Financial Statements (Continued)

15. Related Party Transactions

During the ordinary course of business, the Company has transactions with certain shareholders and other related parties. These transactions primarily consist of purchases of drilling equipment and sales of oilfield service supplies. Following is a summary of significant transactions with such related parties for the nine month periods ended September 30, 2006 and 2007 (in thousands):

	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2007
Sales to and reimbursements from related parties	$ 12,070	$ 72,434
Purchases of services from related parties	$ 3,656	$ 42,544

On June 1, 2006, the Company purchased certain producing well interest from an executive officer and director. The purchase price was approximately $9.0 million in cash. The cash consideration was paid in July 2006.

In August 2006, the Company sold various non-energy related assets to the Company s former President and Chief Operating Officer, N. Malone Mitchell, 3rd, for approximately $6.1 million in cash. The sale transaction resulted in a $0.8 million gain recognized in earnings by the Company in August 2006. The gain is included in gain on sale of assets in the condensed consolidated statements of operations.

In September 2006, the Company entered into a facilities lease with a member of its Board of Directors. The Company believes that the payments to be made under this lease are at fair market rates. Rent expense related to the lease totaled $0.1 million and $1.7 million for the nine month periods ended September 30, 2006 and 2007, respectively. The lease extends to August 2009.

On May 2, 2007, the Company purchased certain leasehold acreage from a partnership controlled by a director. The purchase price was approximately $8.3 million in cash.

On June 11, 2007, the Company purchased certain producing well interests from a director. The purchase price was approximately $3.5 million in cash.

Larclay, L.P. Larclay is a joint venture between the Company and Clayton Williams Energy, Inc. (CWEI) and was formed to acquire drilling rigs and provide land drilling services. Larclay currently owns 12 rigs, one of which has not been assembled. The Company purchased its investment in 2006 and accounts for it under the equity method of accounting. The Company serves as the operations manager of the joint venture. CWEI is responsible for financing and purchasing of the rigs. The Company had sales to and cost reimbursements from Larclay for the nine months ended September 30, 2006 of $0.8 million. The Company had sales to and cost reimbursements from Larclay for the nine months ended September 30, 2007 of $48.9 million. As of December 31, 2006 and September 30, 2007, the Company had accounts receivable related party due from Larclay of $3.0 million and $16.0 million, respectively.

Additionally, the Company made no purchases from Larclay in 2006. The Company had purchases from Larclay for the nine months ended September 30, 2007 of $25.6 million. As of September 30, 2007, the Company had accounts payable related party due to Larclay of $2.2 million.

16. Industry Segment Information

SandRidge has four business segments: Exploration and Production, Drilling and Oilfield Services, Midstream Gas Services, and Other representing its four main business units offering different products and services. The Exploration and Production segment is engaged in the development, acquisition and production of oil and natural gas properties. The Drilling and Oilfield Services segment is engaged in the land contract drilling of oil and natural gas wells. The Midstream Gas Services segment is engaged in the purchasing, gathering, processing and treating of natural gas. The Other segment transports CO_2 to market for use by the Company and others in tertiary oil recovery operations and other miscellaneous operations.

SandRidge Energy, Inc. and Subsidiaries

Notes to Condensed Consolidated Financial Statements (Continued)

Management evaluates the performance of SandRidge s operating segments based on operating income, which is defined as operating revenues less operating expenses and depreciation, depletion and amortization. Summarized financial information concerning our segments is shown in the following table (in thousands):

	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2007
Revenues:		
Exploration and production	$ 50,704	$ 320,984
Elimination of inter-segment revenue	(354)	(574)
Exploration and production, net of inter-segment revenue	50,350	320,410
Drilling and oilfield services	154,295	188,887
Elimination of inter-segment revenue	(48,040)	(131,888)
Drilling and oilfield services, net of inter-segment revenue	106,255	56,999
Midstream gas services	137,329	189,143
Elimination of inter-segment revenue	(46,115)	(118,012)
Midstream gas services, net of inter-segment revenue	91,214	71,131
Other	15,578	19,780
Elimination of inter-segment revenue	(220)	(6,545)
Other, net of inter-segment revenue	15,358	13,235
Total revenues	$ 263,177	$ 461,775
Operating Income:		
Exploration and production	$ 8,203	$ 138,306
Drilling and oilfield services	27,178	14,252
Midstream gas services	3,138	5,958
Other	(8,778)	(20,172)
Total operating income	29,741	138,344
Interest income	448	4,201
Interest expense	(4,090)	(88,630)
Other income (expense)	(241)	3,078

Income before income tax expense	$ 25,858	$ 56,993
Capital Expenditures:		
Exploration and production	$ 88,861	$ 706,550
Drilling and oilfield services	53,832	104,796
Midstream gas services	25,406	45,427
Other	13,132	38,387
Total capital expenditures	$ 181,231	$ 895,160
Depreciation, Depletion and Amortization:		
Exploration and production	$ 14,902	$ 117,329
Drilling and oilfield services	14,070	25,962
Midstream gas services	2,238	4,182
Other	4,828	4,948
Total depreciation, depletion and amortization	$ 36,038	$ 152,421

SandRidge Energy, Inc. and Subsidiaries

Notes to Condensed Consolidated Financial Statements (Continued)

	December 31, 2006	September 30, 2007
Identifiable Asset(1):		
Exploration and production	$ 2,091,459	$ 2,712,621
Drilling and oilfield services	175,169	264,272
Midstream gas services	75,606	108,031
Other	46,150	85,532
Total	$ 2,388,384	$ 3,170,456

(1) Identifiable assets are those used in SandRidge s operations in each industry segment.

17. Subsequent Events

Acquisitions. On October 9, 2007, the Company purchased developed and undeveloped properties located in West Texas from an oil and gas company. The purchase price was approximately $74 million, comprised of $25 million in cash and a $49 million note payable. The $25 million cash consideration paid was funded through a draw on the Company s senior credit facility. All principal and accrued interest (interest at 7% annually) due on the note payable were repaid on November 9, 2007 with proceeds from the Company s initial public offering.

On November 28, 2007, the Company purchased additional ownership in a gas treatment plant and related gathering system located in Pecos County, Texas. The purchase price of approximately $10.0 million was paid in cash.

On November 29, 2007, the Company purchased leasehold acreage and producing well interests located predominately in the WTO from a group of entities. The purchase price of approximately $32.0 million was paid in cash.

Litigation Settlement. On October 29, 2007, the Company entered into an agreement whereby it settled outstanding litigation related to certain property purchased by the Company during July 2007. Under the terms of the agreement, the Company paid $4.5 million to the counterparties on November 15, 2007 and the litigation was dismissed. The amount paid has been included in accounts payable and accrued expenses in the accompanying condensed consolidated balance sheet as of September 30, 2007.

Note Payable. On November 15, 2007, the Company entered into a note payable in the amount of $20 million with a lending institution as a mortgage on the downtown property purchased by the Company during July 2007 (see additional discussion in Note 4). This note is fully secured by one of the buildings and a parking garage located on the downtown property, bears interest at 6.08%, and matures November 15, 2022. Payments of principal and interest in the amount of approximately $0.5 million are due on a quarterly basis through the maturity date. During the next twelve months, the Company expects to make payments of principal and interest on this note totaling $1.0 million and $1.1 million, respectively.

Initial Public Offering. On November 9, 2007, the Company completed an initial public offering (the IPO) of its common stock. The Company sold 28,700,000 shares of SandRidge common stock, including 4,170,000 shares sold directly to an entity controlled by Tom L. Ward. The shares were sold at a price of $26 per share. After deducting underwriting discounts of approximately $38.3 million and estimated offering expenses of approximately $2.5 million, the Company received net proceeds of approximately $705.4 million. This transaction priced after market close on November 5, 2007. In conjunction with the IPO, the underwriters were granted an option to purchase 3,679,500 additional shares of the Company s common stock. The underwriters fully exercised this option and purchased the additional shares on November 6, 2007. After deducting underwriting discounts of approximately $5.7 million, the Company received net proceeds of

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SandRidge Energy, Inc. and Subsidiaries

Notes to Condensed Consolidated Financial Statements (Continued)

approximately $89.9 million from these additional shares. This offering generated total gross proceeds to the Company of $841.8 million and total net proceeds of approximately $795.3 million to us after deducting total underwriting discounts of approximately $44.0 million and other offering expenses estimated to be approximately $2.5 million. The aggregate net proceeds of approximately $795.3 million received by the Company at closing on November 9, 2007 were utilized as follows (in millions):

Repayment of outstanding balance and accrued interest on senior credit facility	$ 515.9
Repayment of note payable and accrued interest incurred in connection with recent acquisition	49.1
Excess cash to fund future capital expenditures	230.3
Total	$ 795.3

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Report of Independent Registered Public Accounting Firm

To the Member
NEG Oil & Gas LLC

We have audited the accompanying combined balance sheets of NEG Oil & Gas LLC and subsidiaries excluding National Energy Group, Inc., and the 103/4% Senior Notes due from National Energy Group, Inc., but including National Energy Group Inc. s 50% membership interest in NEG Holding LLC (collectively, the Company) as of December 31, 2004 and 2005 and the related statements of operations, changes in total member s equity and cash flows for each of the three years in the period ended December 31, 2005. 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 the 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 audit 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 our audits provide a reasonable basis for our opinion.

In our opinion, the combined financial statements referred to above, present fairly, in all material respects, the financial position of NEG Oil & Gas LLC and subsidiaries excluding National Energy Group, Inc. and the 103/4% Senior Notes due from National Energy Group Inc., but including National Energy Group Inc. s 50% membership interest in NEG Holding LLC as of December 31, 2004 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 12 to the financial statements, the Company adopted SFAS No. 143, Accounting for Asset Retirement Obligations on January 1, 2003, which is considered as a change in accounting policy.

/s/ Grant Thornton LLP

Houston, Texas
October 27, 2006

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NEG OIL & GAS LLC AND SUBSIDIARIES, EXCLUDING NATIONAL ENERGY GROUP, INC. AND THE 103/4% SENIOR NOTES DUE FROM NATIONAL ENERGY GROUP, INC., BUT INCLUDING NATIONAL ENERGY GROUP INC. S 50% MEMBERSHIP INTEREST IN NEG HOLDING LLC

COMBINED BALANCE SHEETS

	December 31, 2004	December 31, 2005
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 30,846	$ 102,322
Accounts receivable, net	36,613	53,378
Accounts receivable affiliates	907	
Notes receivable	489	10
Drilling prepayments	3,460	3,281
Deferred tax assets, net	1,943	
Other	4,993	9,798
Total current assets	79,251	168,789
Oil and gas properties, at cost (full cost method)	929,088	1,229,923
Accumulated depreciation, depletion and amortization	(397,870)	(488,560)
Net oil and gas properties	531,218	741,363
Other property and equipment	5,595	6,029
Accumulated depreciation	(4,593)	(4,934)
Net other property and equipment	1,002	1,095
Note receivable	3,090	
Equity investment	2,379	
Restricted deposits	23,519	24,267
Deferred tax asset, net	592	
Other assets	1,245	4,842
Total assets	$ 642,296	$ 940,356
LIABILITIES AND MEMBER S EQUITY		
Current Liabilities:		
Accounts payable	$ 28,914	$ 18,105
Accounts payable revenue	6,265	11,454
Accounts payable affiliates	2,574	1,660
Current portion of notes payable	1,761	2,503
Current portion of note payable to affiliate	10,429	

Advance from affiliate		39,800
Prepayments from partners	749	121
Accrued interest	23	162
Accrued interest affiliates	1,204	2,194
Income tax payable affiliate	3,151	2,749
Derivative financial instruments	8,911	68,039
Total current liabilities	63,981	146,787
Commitments and contingencies		
Credit facility	51,834	300,000
Notes payable, net of current maturities	2,642	
Note payable to affiliate net of current maturities	55,071	
Gas balancing	898	1,108
Derivative financial instruments	7,766	17,893
Other liabilities	250	250
Deferred income tax liability	12,799	
Asset retirement obligation	56,524	41,228
Total liabilities	251,765	507,266
Member s equity	390,531	433,090
Total liabilities and member s equity	$ 642,296	$ 940,356

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

NEG OIL & GAS LLC AND SUBSIDIARIES, EXCLUDING NATIONAL ENERGY GROUP, INC. AND THE 103/4% SENIOR NOTES DUE FROM NATIONAL ENERGY GROUP INC., BUT INCLUDING NATIONAL ENERGY GROUP INC. S 50% MEMBERSHIP INTEREST IN NEG HOLDING LLC

COMBINED STATEMENTS OF OPERATIONS

	For the Years Ended December 31, 2003	2004	2005
	(In thousands)		
Revenues:			
Oil and gas sales gross	$ 100,777	$ 144,430	$ 261,398
Unrealized derivative losses	(2,987)	(9,179)	(69,254)
Oil and gas revenues net	97,790	135,251	192,144
Plant revenues	2,119	2,737	6,711
Total revenues	99,909	137,988	198,855
Costs and expenses:			
Lease operating	11,517	14,912	27,437
Transportation and gathering	1,418	3,144	4,978
Plant and field operations	2,069	3,918	3,769
Production and ad valorem taxes	8,144	10,883	16,560
Depreciation, depletion and amortization	39,409	60,394	91,100
Accretion of asset retirement obligation	339	593	3,019
General and administrative	7,703	11,650	14,152
Total costs and expenses	70,599	105,494	161,015
Operating income	29,310	32,494	37,840
Interest expense	(2,034)	(3,428)	(8,198)
Interest expense affiliate	(971)	(3,054)	(3,047)
Interest income and other	524	930	810
Interest income from related parties	115	150	
Equity in loss on investment	(102)	(519)	(1,118)
Severance tax refund		4,468	
Commitment fee income	125		
(Loss) gain on sale of assets	(8)	1,686	9
Gain on sale of equity investment			5,512
Loss on marketable securities	(954)		
Income before income taxes	26,005	32,727	31,808
Income tax benefit (expense)	12,615	(260)	2,932
Income before minority interest and cumulative effect of accounting change	38,620	32,467	34,740
Minority interest	(1,741)	(812)	

Income before cumulative effect of accounting change	36,879	31,655	34,740
Cumulative effect of accounting change	1,912		
Net income	$ 38,791	$ 31,655	$ 34,740

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

NEG OIL & GAS LLC AND SUBSIDIARIES, EXCLUDING NATIONAL ENERGY GROUP, INC. AND THE 103/4% SENIOR NOTES DUE FROM NATIONAL ENERGY GROUP INC., BUT INCLUDING NATIONAL ENERGY GROUP INC. S 50% MEMBERSHIP INTEREST IN NEG HOLDING LLC

COMBINED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31, 2003	2004	2005
	(In thousands)		
Operating activities:			
Net income	$ 38,791	$ 31,655	$ 34,740
Noncash adjustments:			
Deferred income tax benefit	(14,953)	(144)	(2,935)
Depreciation depletion and amortization	39,409	60,394	91,100
Minority interest	1,741	812	
Unrealized derivative losses	2,987	9,179	69,254
(Gain) loss on sale of assets	8	(1,686)	(9)
Accretion of asset retirement obligation	339	593	3,019
Equity in loss on investment	102	519	1,118
Gain on sale of equity investment			(5,512)
Provision for doubtful accounts		790	470
Cumulative effect of accounting change	(1,912)		
Interest income-restricted deposits			(494)
Amortization of note discount		281	81
Amortization of note costs	793	494	1,148
Changes in operating assets and liabilities:			
Accounts receivable	2,677	(6,340)	(13,496)
Drilling prepayments	(1,138)	249	179
Derivative deposit	100	1,700	
Other assets	820	(1,030)	(4,883)
Note receivable	(1,832)	(1,258)	3,098
Accounts payable and accrued liabilities	237	12,014	(8,545)
Net cash provided by operating activities	68,169	108,222	168,333
Investing activities:			
Acquisition, exploration, and development costs	(40,962)	(114,974)	(315,880)
Proceeds from sales of oil and gas properties	1,436	4,981	1,329
Purchases of furniture, fixtures and equipment	(227)	(289)	(511)
Proceeds from sale of furniture, fixtures and equipment			12
Equity investment	(1,800)	(1,200)	(454)
Investment in restricted deposits			(4,973)
Proceeds from sale of equity investment			7,227
Net cash used in investing activities	(41,553)	(111,482)	(313,250)
Financing activities:			

Debt issuance costs	(952)	(440)	(4,666)
Net cash contributed by member	15,312	23,753	
Repurchase of membership interest		(4,136)	
Proceeds from affiliate borrowings			161,800
Repayment of affiliate borrowings			(98,357)
Guaranteed payment to member	(18,229)	(15,978)	(15,978)
Priority distribution	(40,506)		
Equity Contribution			5,326
Dividend payment to member			(78,000)
Proceeds from credit facility	91,625	8,000	379,100
Principal payments on debt	(55,514)	(9,365)	(1,898)
Repayment of credit facility	(1,090)		(130,934)
Net cash provided (used) by financing activities	(9,354)	1,834	216,393
Increase in cash and cash equivalents	17,262	(1,426)	71,476
Cash and cash equivalents at beginning of period	15,010	32,272	30,846
Cash and cash equivalents at end of period	$ 32,272	$ 30,846	$ 102,322
Supplemental cash flow information:			
Cash paid for interest	$ 1,681	$ 5,471	$ 8,483
Cash paid for income taxes	$ 800	$ 50	$
Distribution of member note payable	$ 10,940	$	$

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

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COMBINED STATEMENT OF CHANGES IN TOTAL MEMBER S EQUITY

		(In thousands)
Total equity December 31, 2002	$	199,842
Contribution from member National Onshore		116,253
Guaranteed payment to member		(18,229)
Payment of priority amount to member		(51,446)
Net income		38,791
Total member s equity December 31, 2003		285,211
Contribution from member National Offshore		91,561
Contribution from member National Onshore minority interest		2,218
Purchase of minority membership interest		(4,136)
Guaranteed payment to member		(15,978)
Net income		31,655
Total member s equity December 31, 2004		390,531
Contribution of Notes Payable to AREP		89,143
Equity Contribution		5,326
Contribution of deferred tax assets		(5,471)
Contribution of deferred tax liabilities		12,799
Guaranteed payment to member		(15,978)
Dividend distribution		(78,000)
Net income		34,740
Total member s equity December 31, 2005	$	433,090

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

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NOTES TO COMBINED FINANCIAL STATEMENTS
December 31, 2003, 2004, 2005

1. Organization and Background

The accompanying combined financial statements present NEG Oil & Gas LLC and subsidiaries, excluding National Energy Group, Inc. and the 103/4% Senior Notes due from National Energy Group, but including National Energy Group s 50% membership interest in NEG Holding LLC (collectively, the Company). The Company is an oil and natural gas exploration and production company engaged in the exploration, development, production and operations of natural gas and oil properties, primarily located in Texas, Oklahoma, Arkansas and Louisiana (both onshore and in the Gulf of Mexico).

NEG Oil & Gas LLC is wholly-owned by American Real Estate Holdings Limited Partnership (AREH). AREH is 99% owned by American Real Estate Partners, L.P. (AREP). AREP is a publicly traded limited partnership that is majority owned by Mr. Carl C. Icahn.

NEG Oil & Gas LLC was formed on December 2, 2004 to hold the oil and gas investments of the Company s ultimate parent company, AREP and, as of December 31, 2005 had the following assets and operations:

A 50.01% ownership interest in National Energy Group, Inc (National Energy Group), a publicly traded oil and gas management company. National Energy Group s principal asset consists of its 50% membership interest in NEG Holding LLC (Holding, LLC).

$148.6 million principal amount of 103/4% Senior Notes due from National Energy Group (the 103/4% Senior Notes).

A 50% managing membership interest in Holding, LLC.

The oil and gas operations of National Onshore LP (formerly TransTexas Gas Corporation); and

The oil and gas operations of National Offshore LP (formerly Panaco, Inc.)

All of the above assets initially were acquired by entities owned or controlled by Mr. Icahn and subsequently acquired by AREP (through subsidiaries) in various purchase transactions. In accordance with generally accepted accounting principles, assets transferred between entities under common control are accounted for at historical cost similar to a pooling of interest and the financial statements are combined from the date of acquisition by an entity under common control. The financial statements include the combined results of operations, financial position and cash flows of each of the above entities since its initial acquisition by entities owned or controlled by Mr. Icahn (the Period of Common Control).

On September 7, 2006, AREP signed a letter of intent to sell NEG Oil & Gas LLC and subsidiaries, excluding National Energy Group, Inc. and the 103/4% Senior Notes due from National Energy Group, but including National Energy Group s 50% membership interest in Holding LLC to Riata Energy, Inc., DBA SandRidge Energy, Inc. (Riata Energy) The combined financial statements include the entities to be sold to Riata Energy.

Background

National Energy Group, Inc. In February, 1999 National Energy Group was placed under involuntary, court ordered bankruptcy protection. Effective August 4, 2000 National Energy Group emerged from involuntary bankruptcy protection with affiliates of Mr. Icahn owning 49.9% of the common stock and $165 million principal amount of debt securities (Senior Notes). As mandated by National Energy Group s Plan of Reorganization, Holding LLC was formed and on September 1, 2001, National Energy Group contributed to Holding LLC all of its oil and natural gas properties in exchange for an initial membership

NEG OIL & GAS LLC AND SUBSIDIARIES, EXCLUDING NATIONAL ENERGY GROUP, INC. AND THE 103/4% SENIOR NOTES DUE FROM NATIONAL ENERGY GROUP INC., BUT INCLUDING NATIONAL ENERGY GROUP INC. S 50% MEMBERSHIP INTEREST IN NEG HOLDING LLC

NOTES TO COMBINED FINANCIAL STATEMENTS (Continued)

interest in Holding LLC. National Energy Group retained $4.3 million in cash. On September 1, 2001, an affiliate of Mr. Icahn contributed to Holding LLC oil and natural gas assets, cash and a $10.9 million note receivable from National Energy Group in exchange for the remaining membership interest, which was designated the managing membership interest. Concurrently, in September, 2001, but effective as of May 2001, Holding LLC formed a 100% owned subsidiary, NEG Operating Company, LLC (Operating LLC) and contributed all of its oil and natural gas assets to Operating LLC.

In October 2003, AREP acquired all outstanding Senior Notes ($148.6 million principal amount at October 2003) and 5,584,044 shares of common stock of National Energy Group from entities affiliated with Mr. Icahn for aggregate consideration of approximately $148.1 million plus approximately $6.7 million of accrued interest on the Senior Notes. As a result of this transaction and the acquisition by AREP of additional shares of National Energy Group, AREP beneficially owned 50.01% of the outstanding stock of National Energy Group and had effective control. In June 2005, all of the stock of National Energy Group and the $148.6 million principal amount of Senior Notes owned by AREP was contributed to the Company and National Energy Group became a 50.01% owned subsidiary. The accrued, but unpaid interest on the $148.6 million principal amount of Senior Notes was retained by AREP. National Energy Group and the Senior Notes will be retained by AREP and not purchased by Riata Energy.

NEG Holding LLC On June 30, 2005, AREP acquired the managing membership interest in Holding LLC from an affiliate of Mr. Icahn for an aggregate consideration of approximately $320 million. The membership interest acquired constituted all of the membership interests other than the membership interest already owned by National Energy Group. The combined financial statements include the consolidation of the acquired 50% membership interest in Holding LLC, together with the 50% membership interest owned by National Energy Group. The Period of Common Control for Holding LLC began on September 1, 2001, the initial funding of Holding LLC.

The Holding LLC Operating Agreement Holding LLC is governed by an operating agreement effective May 12, 2001, which provides for management and control of Holding LLC by the Company and distributions to National Energy Group and the Company based on a prescribed order of distributions (the Holding LLC Operating Agreement).

Order of Distributions

Pursuant to the Holding LLC Operating Agreement, distributions from Holding LLC to National Energy Group and the Company shall be made in the following order:

1. Guaranteed payments (Guaranteed Payments) are to be paid to National Energy Group, calculated on an annual interest rate of 103/4% on the outstanding priority amount (Priority Amount). The Priority Amount includes all outstanding debt owed to the Company, including the amount of National Energy Group s 103/4% Senior Notes. As of December 31, 2005, the Priority Amount was $148.6 million. The Guaranteed Payments will be made on a semi-annual basis.

2. The Priority Amount is to be paid to National Energy Group. Such payment is to occur by November 6, 2006.

3. An amount equal to the Priority Amount and all Guaranteed Payments paid to National Energy Group, plus any additional capital contributions made by the Company, less any distributions previously made by Holding LLC to the Company, is to be paid to the Company.

4. An amount equal to the aggregate annual interest (calculated at prime plus 1/2% on the sum of the Guaranteed Payments), plus any unpaid interest for prior years (calculated at prime plus 1/2% on the sum

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NOTES TO COMBINED FINANCIAL STATEMENTS (Continued)

of the Guaranteed Payments), less any distributions previously made by Holding LLC to the Company, is to be paid to NEG Oil & Gas.

5. After the above distributions have been made, any additional distributions will be made in accordance with the ratio of NEG Oil & Gas and National Energy Group s respective capital accounts. (Capital accounts as defined in the Holding LLC Operating Agreement.)

Redemption Provision in the Holding LLC Operating Agreement

The Holding LLC Operating Agreement contains a provision that allows the managing member (NEG Oil & Gas), at any time, in its sole discretion, to redeem National Energy Group s membership interest in Holding LLC at a price equal to the fair market value of such interest determined as if Holding LLC had sold all of its assets for fair market value and liquidated.

Prior to closing the Riata Energy purchase transaction, AREP will cause NEG Oil & Gas to exercise the redemption provision and dividend the 103/4% Senior Notes to AREP or enter into transactions with a similar effect such that NEG Oil & Gas will own 100% of Holding LLC and no longer own the 103/4% Senior Notes receivable from National Energy Group. AREP will indemnify NEG Oil & Gas for any costs associated with the exercise of the redemption provision. The Holding LLC Operating Agreement will be cancelled.

National Onshore LP On November 14, 2002, National Onshore filed a voluntary petition for relief under Chapter 11 of the U.S. Bankruptcy Code in the United States Bankruptcy Court for the Southern District of Texas, Corpus Christi Division. National Onshore s First Amended Joint Plan of Reorganization submitted by an entity affiliated with Mr. Icahn, as modified on July 8, 2003 (the National Onshore Plan), was confirmed by the Bankruptcy Court on August 14, 2003 effective August 28, 2003.

As of the effective date of the National Onshore Plan, an entity affiliated with Mr. Icahn owned 89% of the outstanding shares of National Onshore. During June 2004, the entity affiliated with Mr. Icahn acquired an additional 5.7% of the outstanding shares of National Onshore from certain other stockholders. During December 2004, National Onshore acquired the remaining 5.3% of the outstanding shares that were not owned by an affiliate of Mr. Icahn. The difference between the purchase price for both acquisitions and the minority interest liability was treated as a purchase price adjustment which reduced the full cost pool.

On December 6, 2004, AREP purchased from an affiliates of Mr. Icahn $27.5 million aggregate principal amount, or 100%, of the outstanding term notes issued by National Onshore (the National Onshore Notes). The purchase price was $28.2 million, which equals the principal amount of the National Onshore Notes plus accrued unpaid interest. The notes are payable annually in equal consecutive annual payments of $5.0 million, with the final installment due August 28, 2008. Interest is payable semi-annually in February and August at the rate of 10% per annum.

On April 6, 2005, AREP acquired 100% of the outstanding stock of National Onshore from entities owned by Mr. Icahn for an aggregate consideration of $180 million. The operations of National Onshore are considered to have been contributed to the Company on August 28, 2003 at a historical cost of approximately $116.3 million, representing the historical basis in the assets and liabilities of National Onshore of the entities owned by Mr. Icahn. AREP contributed the National Onshore Notes, but not the accrued and unpaid interest through the date of contribution, to the Company on June 30, 2005. The Period of Common Control of National Onshore began on August 28, 2003.

National Offshore LP On July 16, 2002, National Offshore filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court of the Southern District of Texas. On November 3, 2004, the Bankruptcy Court entered a confirmation order for the National

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NOTES TO COMBINED FINANCIAL STATEMENTS (Continued)

Offshore s Plan of Reorganization (the National Offshore Plan). The National Offshore Plan became effective November 16, 2004 and National Offshore began operating as a reorganized entity. Upon emergence from bankruptcy, an entity controlled by Mr. Icahn owned 100% of the outstanding common stock of National Offshore.

On December 6, 2004, AREP purchased $38.0 million aggregate principal amount of term loans issued by National Offshore, which constituted 100% of the outstanding term loans of National Offshore from an affiliate of Mr. Icahn. On June 30, 2005, AREP contributed the National Offshore term loan, but not the accrued and unpaid interest through the date of contribution, to the Company.

On June 30, 2005, AREP acquired 100% of the equity of National Offshore from affiliates of Mr. Icahn for consideration valued at approximately $125.0 million. The Period of Common Control for National Offshore began on November 16, 2004 when National Offshore emerged from bankruptcy. The acquisition of National Offshore has been recorded effective December 31, 2004. The historical cost of approximately $91.6 million, representing the historical basis in the assets and liabilities of National Offshore of the affiliates of Mr. Icahn, was considered to have been contributed to the Company on December 31, 2004.

2. Significant Accounting Policies

Basis of Presentation

The combined financial statements include the accounts of NEG Oil & Gas LLC and subsidiaries excluding National Energy Group and the 103/4% Senior Notes due from National Energy Group, but including National Energy Group s 50% membership interest in NEG Holding LLC (the Company). All material intercompany accounts and transactions have been eliminated in the combined financial statements. Investments in subsidiaries over which the Company has significant influence, but not control, are reported using the equity method.

Accounting Estimates

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 and 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 these estimates.

Cash and Cash Equivalents

Cash and cash equivalents may include demand deposits, short-term commercial paper, and/or money-market investments with maturities of three months or less when purchased. Cash in bank deposit accounts are generally maintained at high credit quality financial institutions and may exceed federally insured limits. The Company has not experienced any losses in such accounts and does not believe it is exposed to any significant risk of loss.

Oil and Natural Gas Properties

The Company utilizes the full cost method of accounting for its crude oil and natural gas properties. Under the full cost method, all productive and nonproductive costs incurred in connection with the acquisition, exploration, and development of crude oil and natural gas reserves are capitalized and amortized on the units-of-production method based upon total proved reserves. The Company elects to include its current unevaluated properties in the full cost pool. Conveyances of properties, including gains or losses on

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NOTES TO COMBINED FINANCIAL STATEMENTS (Continued)

abandonments of properties, are treated as adjustments to the cost of crude oil and natural gas properties, with no gain or loss recognized unless the sale or disposition represents a significant portion of the Company s oil and natural gas reserves.

Under the full cost method, the net book value of oil and natural gas properties, less related deferred income taxes, may not exceed the estimated after-tax future net revenues from proved oil and natural gas properties, discounted at 10% per year (the ceiling limitation) plus the lower of cost or fair value of unevaluated properties, if any. In arriving at estimated future net revenues, estimated lease operating expenses, development costs, abandonment costs, certain production related ad-valorem taxes, and estimated corporate income taxes relating to oil and gas properties, if any, are deducted. In calculating future net revenues, prices and costs in effect at the time of the calculation are held constant indefinitely, except for changes which are fixed and determinable by existing contracts. Such contracts may include derivative contracts that meet the accounting requirements and are documented, designated and accounted for as cash flow hedges. None of the Company s derivatives contracts were accounted for as cash flow hedges. Consequently, prices were held constant indefinitely. The net book value is compared to the ceiling limitation on a quarterly basis. The excess, if any, of the net book value above the ceiling limitation is required to be written off as a non-cash expense. The Company did not incur a ceiling writedown in 2003, 2004 and 2005. There can be no assurance that there will not be writedowns in future periods under the full cost method of accounting as a result of sustained decreases in oil and natural gas prices or other factors.

The Company has capitalized internal costs of $0.6 million; $1.0 million and $1.1 million for the years ended December 31, 2003, 2004 and 2005, respectively, as cost of oil and natural gas properties. Oil and natural gas properties include cumulative capitalized internal costs of $2.4 million and $3.5 million as of December 31, 2004 and 2005. Such capitalized costs include salaries and related benefits of individuals directly involved in the Company s acquisition, exploration, and development activities based on a percentage of their salaries. These costs do not include any costs related to production, general corporate overhead, or similar activities.

Costs associated with production and general corporate activities are expensed in the period incurred. Production costs are costs incurred to operate and maintain the Company s wells and related equipment and include cost of labor, well service and repair, location maintenance, power and fuel, transportation, cost of product, property taxes, production and severance taxes and production related general and administrative costs.

The Company receives reimbursement for administrative and overhead expenses incurred on behalf of other working interest owners on properties the Company operates. Such reimbursements are recorded as reductions to general and administrative expenses to the extent of actual costs incurred. Reimbursements in excess of actual costs incurred, if any, are credited to the full cost pool to be recognized through lower cost amortization as production occurs. Historically, the Company has not received any administrative and overhead reimbursements in excess of costs incurred.

The Company is subject to extensive federal, state, and local environmental laws and regulations. These laws, which are constantly changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit.

Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a noncapital nature are recorded when environmental assessment and/or remediation is probable, and the costs can be reasonably estimated.

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NOTES TO COMBINED FINANCIAL STATEMENTS (Continued)

The Company s operations are subject to all of the risks inherent in oil and natural gas exploration, drilling and production. These hazards can result in substantial losses to the Company due to personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage, or suspension of operations. The Company maintains insurance of various types customary in the industry to cover its operations and believes it is insured prudently against certain of these risks. In addition, the Company maintains operator s extra expense coverage that provides coverage for the care, custody and control of wells drilled by the Company. The Company s insurance does not cover every potential risk associated with the drilling and production of oil and natural gas. As a prudent operator, the Company does maintain levels of insurance customary in the industry to limit its financial exposure in the event of a substantial environmental claim resulting from sudden and accidental discharges. However, 100% coverage is not maintained. The occurrence of a significant adverse event, the risks of which are not fully covered by insurance, could have a material adverse effect on the Company s financial condition and results of operations. Moreover, no assurance can be given that the Company will be able to maintain adequate insurance in the future at rates it considers reasonable. The Company believes that it operates in compliance with government regulations and in accordance with safety standards which meet or exceed industry standards.

Other Property and Equipment

Other property and equipment includes furniture, fixtures, and other equipment. Such assets are recorded at cost and are depreciated over their estimated useful lives using the straight-line method.

The Company s investment in Longfellow Ranch Field includes an interest in a gas separation facility. This investment is included in the oil and natural gas properties and depleted over the life of the reserves.

Maintenance and repairs are charged against income when incurred; renewals and betterments, which extend the useful lives of property and equipment, are capitalized.

Income Taxes

NEG Oil & Gas and Holding LLC are taxed as partnerships under applicable federal and state laws. No income taxes have been provided on the income of NEG Oil & Gas since these taxes are the responsibility of the member. Income tax liabilities and assets reflect the obligations and assets of its consolidated entities.

National Onshore and National Offshore were organized as corporations and were subject to corporate income tax until their acquisition by NEG Oil & Gas. For income tax purposes, through the date of acquisition by NEG Oil & Gas, the taxable income or loss of National Onshore and its subsidiaries and National Offshore are included in the consolidated income tax return of the Starfire Holding Corp. (Starfire) controlled group. National Onshore and its subsidiaries and National Offshore entered into tax allocation agreements with Starfire, an entity owned by Mr. Icahn. The tax allocation agreements provide for payments of tax liabilities to Starfire, calculated as if National Onshore and its subsidiaries and National Offshore each filed a consolidated income tax return separate from the Starfire controlled group. Additionally, the agreements provide for payments from Starfire to National Onshore and its subsidiaries or National Offshore for any previously paid tax liabilities that are reduced as a result of subsequent determinations by any government authority, or as a result of any tax losses or credits that are allowed to be carried back to prior years.

The Company accounts for income tax assets and liabilities of its consolidated corporate entities in accordance with Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes (SFAS 109). SFAS 109 requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the financial statements carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax

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NOTES TO COMBINED FINANCIAL STATEMENTS (Continued)

rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the period that includes the enactment date. The Company maintains valuation allowances where it is determined more likely than not that all or a portion of a deferred tax asset will not be realized. Changes in valuation allowances from period to period are included in the Company s tax provision in the period of change. In determining whether a valuation allowance is warranted, the Company takes into account such factors as prior earnings history, expected future earnings, carryback and carryforward periods, and tax planning strategies.

Accounts Receivable

The Company sells crude oil and natural gas to various customers. In addition, the Company participates with other parties in the operation of crude oil and natural gas wells. Substantially all of the Company s accounts receivable are due from either purchasers of crude oil and natural gas or participants in crude oil and natural gas wells for which the Company serves as the operator. Generally, operators of crude oil and natural gas properties have the right to offset future revenues against unpaid charges related to operated wells. Crude oil and natural gas sales are generally unsecured.

The allowance for doubtful accounts is an estimate of the losses in the Company s accounts receivable. The Company periodically reviews the accounts receivable from customers for any collectability issues. An allowance for doubtful accounts is established based on reviews of individual customer accounts, recent loss experience, current economic conditions, and other pertinent factors. Accounts deemed uncollectible are charged to the allowance. Provisions for bad debts and recoveries on accounts previously charged-off are added to the allowance.

Accounts receivable allowance for bad debt totaled approximately $0.3 million at December 31, 2004 and $0.2 million at December 31, 2005. At December 31, 2004 and 2005, the carrying value of the Company s accounts receivable approximates fair value.

Revenue Recognition

Revenues from the sale of natural gas and oil produced are recognized upon the passage of title, net of royalties.

Natural Gas Production Imbalances

The Company accounts for natural gas production imbalances using the sales method, whereby the Company recognizes revenue on all natural gas sold to its customers notwithstanding the fact that its ownership may be less than 100% of the natural gas sold. Liabilities are recorded by the Company for imbalances greater than the Company s proportionate share of remaining estimated natural gas reserves. The Company has recorded a liability for gas balancing of $0.9 million at December 31, 2004 and $1.1 million at December 31, 2005.

Comprehensive Income

Comprehensive income is defined as the change in equity of a business enterprise during a period from transactions and other events and circumstances from non-owner sources. There were no differences between net earnings and total comprehensive income in 2003, 2004 and 2005.

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NOTES TO COMBINED FINANCIAL STATEMENTS (Continued)

Derivatives

From time to time, the Company enters into various derivative instruments consisting principally of no cost collar options (the Derivative Contracts) to reduce its exposure to price risk in the spot market for natural gas and oil. The Company follows Statement of Financial Accounting Standards No. 133 (SFAS 133), Accounting for Derivative Instruments and Hedging Activities, which was amended by Statement of Financial Accounting Standards No. 138, Accounting for Certain Derivative Instruments and Certain Hedging Activities. These pronouncements established accounting and reporting standards for derivative instruments and for hedging activities, which generally require recognition of all derivatives as either assets or liabilities in the balance sheet at their fair value. The accounting for changes in fair value depends on the intended use of the derivative and its resulting designation. The Company elected not to designate these instruments as hedges for accounting purposes, accordingly the cash settlements and valuation gains and losses are included in oil and natural gas sales. The following summarizes the cash settlements and valuation gains and losses for the years ended December 31, 2003, 2004 and 2005 (amounts in thousands):

	2003	2004	2005
Realized loss (net cash payments)	$ 8,309	$ 16,625	$ 51,263
Unrealized loss	2,987	9,179	69,254
Loss on Derivative Contracts	$ 11,296	$ 25,804	$ 120,517

The following is a summary of the Company s Derivative Contracts as of December 31, 2005:

Type of Contract	Production Month	Volume per Month	Floor	Ceiling
No cost collars	Jan-Dec 2006	31,000 Bbls	$ 41.65	$ 45.25
No cost collars	Jan-Dec 2006	16,000 Bbls	41.75	45.40
No cost collars	Jan-Dec 2006	570,000 MmBtu	6.00	7.25
No cost collars	Jan-Dec 2006	120,000 MmBtu	6.00	7.28
No cost collars	Jan-Dec 2006	500,000 MmBtu	4.50	5.00
No cost collars	Jan-Dec 2006	46,000 Bbls	60.00	68.50
(The Company participates in a second ceiling at $84.50 on the 46,000 Bbls)				
No cost collars	Jan-Dec 2007	30,000 Bbls	57.00	70.50
No cost collars	Jan-Dec 2007	30,000 Bbls	57.50	72.00
No cost collars	Jan-Dec 2007	930,000 MmBtu	8.00	10.23
No cost collars	Jan-Dec 2008	46,000 Bbls	55.00	69.00
No cost collars	Jan-Dec 2008	750,000 MmBtu	7.00	10.35

While the use of derivative contracts can limit the downside risk of adverse price movements, it may also limit future gains from favorable movements. The Company addresses market risk by selecting instruments whose value fluctuations correlate strongly with the underlying commodity. Credit risk related to derivative activities is managed by requiring minimum credit standards for counter parties, periodic settlements, and mark to market valuations.

A liability of $16.7 million (including a current liability of $8.9 million) and $85.9 million (including a current liability of $68.0 million) was recorded by the Company as of December 31, 2004 and 2005 respectively, in connection with these contracts. As of December 31, 2004, the Company had issued $11.0 million in letters of credit securing the Company s derivative position. During 2005, the Company was required to provide security to counter parties for its Derivative Contracts in loss positions.

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NOTES TO COMBINED FINANCIAL STATEMENTS (Continued)

On December 22, 2005, concurrent with the execution of the Company s new credit facility (see note 9) the Company novated all of Derivative Contracts with Shell Trading (US) outstanding as of that date with identical Derivative Contracts with Citicorp (USA), Inc. as the counter party. Under this transaction, no contracts were settled, Citicorp (USA) replaced Shell Trading (US) as the counter party and no gain or loss was recorded. Under the new credit facility, Derivatives Contracts with certain lenders under the credit facility do not require cash collateral or letters of credit and rank pari passu with the credit facility. All cash collateral and letters of credit have been released as of December 31, 2005.

Accounting for Asset Retirement Obligations

The Company accounts for its asset retirement obligations under Statement of Financial Accounting Standards No. 143 (SFAS 143), Accounting for Asset Retirement Obligations. SFAS 143 provides accounting requirements for costs associated with legal obligations to retire tangible, long-lived assets. Under SFAS 143, an asset retirement obligation is recorded at fair value in the period in which it is incurred by increasing the carrying amount of the related long-lived asset. In each subsequent period, the liability is accreted to its present value and the capitalized cost is depreciated over the useful life of the related asset.

The Company s asset retirement obligation represents expected future costs to plug and abandon its wells, dismantle facilities, and reclamate sites at the end of the related assets useful lives.

Recent Accounting Pronouncements

On December 16, 2004, the FASB issued Statement 123 (revised 2004), Share-Based Payment that will require compensation costs related to share-based payment transactions (e.g., issuance of stock options and restricted stock) to be recognized in the financial statements. With limited exceptions, the amount of compensation cost will be measured based on the grant-date fair value of the equity or liability instruments issued. In addition, liability awards will be remeasured each reporting period. Compensation cost will be recognized over the period that an employee provides service in exchange for the award. Statement 123(R) replaces SFAS 123, Accounting for Stock-Based Compensation, and supersedes Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees. For us, SFAS 123(R) is effective for the first reporting period beginning after June 15, 2005. Entities that use the fair-value-based method for either recognition or disclosure under SFAS 123 are required to apply SFAS 123(R)using a modified version of prospective application. Under this method, an entity records compensation expense for all awards it grants after the date of adoption. In addition, the entity is required to record compensation expense for the unvested portion of previously granted awards that remain outstanding at the date of adoption. In addition, entities may elect to adopt SFAS 123(R)using a modified retrospective method whereby previously issued financial statements are restated based on the expense previously calculated and reported in their pro forma footnote disclosures. The Company had no share based payments subject to this standard.

In December 2004, the FASB issued Statement 153, Exchanges of Nonmonetary Assets , an amendment of APB Opinion No. 29, to clarify the accounting for nonmonetary exchanges of similar productive assets. SFAS 153 provides a general exception from fair value measurement for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. The Statement will be applied prospectively and is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. The Company does not have any nonmonetary transactions for any period presented that this Statement would apply.

In March 2005, the FASB issued Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations an Interpretation of FASB Statement No. 143 (Interpretation). This Interpretation clarifies

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that the term conditional asset retirement obligation as used in FASB Statement No. 143, Accounting for Asset Retirement Obligations, refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. Thus, the timing and (or) method of settlement may be conditional on a future event. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. This Interpretation also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. This Interpretation is effective for the Company s year ended December 31, 2005. The adoption of this Interpretation did not impact the Company s combined financial position or results of operations.

In May 2005, the FASB issued SFAS No. 154, Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3 (SFAS No. 154). SFAS No. 154 requires retrospective application to prior period financial statements for changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS No. 154 also requires that retrospective application of a change in accounting principle be limited to the direct effects of the change. Indirect effects of a change in accounting principle should be recognized in the period of the accounting change. SFAS No. 154 will become effective for the Company s fiscal year beginning January 1, 2006. The impact of SFAS No. 154 will depend on the nature and extent of any voluntary accounting changes and correction of errors after the effective date, but management does not currently expect SFAS No. 154 to have a material impact on the Company s combined financial position, results of operations or cash flows.

On February 16, 2006, the FASB issued Statement 155, Accounting for Certain Hybrid Instruments an amendment of FASB Statements No. 133 and 140. The statement amends Statement 133 to permit fair value measurement for certain hybrid financial instruments that contain an embedded derivative, provides additional guidance on the applicability of Statement 133 and 140 to certain financial instruments and subordinated concentrations of credit risk. The new standard is effective for the first fiscal year that begins after September 15, 2006 (January 1, 2007 for the Company). We have no hybrid instruments subject to this standard.

3. Management Agreements

The management and operation of Operating LLC is being undertaken by National Energy Group pursuant to the Management Agreement (the Operating LLC Management Agreement) which Operating LLC entered into with National Energy Group. However, neither National Energy Group s officers nor directors control the strategic direction of Operating LLC s oil and natural gas business, including oil and natural gas drilling and capital investments, which are controlled by the managing member of Holding LLC (NEG Oil & Gas). The Operating LLC management agreement provides that National Energy Group will manage Operating LLC s oil and natural gas assets and business until the earlier of November 1, 2006, or such time as Operating LLC no longer owns any of the managed oil and natural gas properties. National Energy Group s employees conduct the day-to-day operations of Operating LLC s oil and natural gas business, and all costs and expenses incurred in the operation of the oil and natural gas properties are borne by Operating LLC, although the Operating LLC Management Agreement provides that the salary of National Energy Group s Chief Executive Officer shall be 70% attributable to the managed oil and natural gas properties, and the salaries of each of the General Counsel and Chief Financial Officer shall be 20% attributable to the managed oil and natural gas properties. In exchange for National Energy Group s management services, Operating LLC pays National Energy Group a management fee equal to 115% of the actual direct and indirect administrative and reasonable overhead costs that National Energy Group incurs in operating the oil and natural gas

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properties. National Energy Group or Operating LLC may seek to change the management fee to within the range of 110%-115% as such change is deemed warranted. However, both have agreed to consult with each other to ensure that such administrative and reasonable overhead costs attributable to the managed properties are properly reflected in the management fee that is paid. In addition, Operating LLC has agreed to indemnify National Energy Group to the extent National Energy Group incurs any liabilities in connection with National Energy Group s operation of the assets and properties of Operating LLC, except to the extent of National Energy Group s gross negligence or misconduct. Operating LLC incurred $6.6 million, $6.2 million and $5.6 million in general and administrative expenses for the years ended December 31, 2003, 2004 and 2005, respectively under this agreement.

On August 28, 2003, National Energy Group entered into a management agreement to manage the oil and natural gas business of National Onshore. The National Onshore management agreement was entered in connection with a plan of reorganization for National Onshore proposed by Thornwood Associates LP, an entity affiliated with Carl C. Icahn (the National Onshore Plan). On August 28, 2003, the United States Bankruptcy Court, Southern District of Texas, issued an order confirming the National Onshore Plan. NEG Oil & Gas owns all of the reorganized National Onshore, which is engaged in the exploration, production and transmission of oil and natural gas, primarily in South Texas, including the Eagle Bay field in Galveston Bay, Texas and the Southwest Bonus field located in Wharton County, Texas. Bob G. Alexander and Philip D. Devlin, National Energy Group s President and CEO, and National Energy Group s Vice President, Secretary and General Counsel, respectively, have been appointed to the reorganized National Onshore Board of Directors and act as the two principal officers of National Onshore and its subsidiaries, Galveston Bay Pipeline Corporation and Galveston Bay Processing Corporation. Randall D. Cooley, National Energy Group s Vice President and CFO, has been appointed Treasurer of reorganized National Onshore and its subsidiaries.

The National Onshore Management Agreement provides that National Energy Group shall be responsible for and have authority with respect to all of the day-to-day management of National Onshore business, but will not function as a Disbursing Agent as such term is defined in the National Onshore Plan. As consideration for National Energy Group services in managing the National Onshore business, National Energy Group receives a monthly fee of $0.3 million. The National Onshore Management Agreement is terminable (i) upon 30 days prior written notice by National Onshore, (ii) upon 90 days prior written notice by National Energy Group, (iii) upon 30 days following any day where High River designees no longer constitute the National Onshore Board of Directors, unless otherwise waived by the newly-constituted Board of Directors of National Onshore, or (iv) as otherwise determined by the Bankruptcy Court. The Company recorded $1.4 million, $4.7 million and $4.8 million in general and administrative expenses for the years ended December 31, 2003, and 2004 and 2005, respectively, under this agreement.

On November 3, 2004, the United States Bankruptcy Court for the Southern District of Texas issued an order effective November 16, 2004 confirming a plan of reorganization for National Offshore (National Offshore Plan). In connection with the National Offshore Plan, National Energy Group entered into a Management Agreement with National Offshore (the National Offshore Management Agreement) pursuant to the Bankruptcy Court s order confirming the effective date of the National Offshore Plan. NEG Oil & Gas owns all of the reorganized National Offshore. Mr. Bob G. Alexander, National Energy Group s President and CEO, has been appointed to the reorganized National Offshore Board of Directors and acts as the reorganized National Offshore s President. Mr. Philip D. Devlin, National Energy Group s Vice President, General Counsel and Secretary, has been appointed to serve in the same capacities for National Offshore. Mr. Randall D. Cooley, National Energy Group s Vice President and CFO, has been appointed as

Treasurer of the reorganized National Offshore. In exchange for management services, National Energy Group receives a monthly fee equal to 115% of the actual direct and indirect administrative overhead costs that are incurred in operating and administering the National Offshore oil and natural gas properties. The Company recorded $0.7 million and $4.2 million in

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general and administrative expenses for the years ended December 31, 2004 and 2005, respectively, under this agreement.

Substantially concurrent with the Riata Energy purchase transaction the management agreements will be terminated.

4. Contributions of National Onshore and National Offshore

National Onshore On August 28, 2003, the effective date of the confirmation of National Onshore s bankruptcy plan, an entity affiliated with Mr. Icahn owned 89% of the outstanding shares of National Onshore. The assets and liabilities of National Onshore were considered to have been contributed to the Company on that date at the historical cost of the entity affiliated with Mr. Icahn as follows (amounts in thousands).

Assets contributed	
Cash and cash equivalents	$ 15,312
Accounts receivable	11,236
Drilling prepayments	505
Other current assets	1,318
Oil and natural gas properties	186,288
Other assets	226
Total assets	214,885
Liabilities assumed	
Accounts payable	3,761
Current maturities of long-term debt	6,038
Accrued liabilities	10,158
Accounts payable other	27
Long-term debt, net of current maturities	4,266
Note payable to affiliate net of current maturities	27,500
Production payments net of current maturities	5,617
Other liabilities	2,096
Income tax liability	27,926
Asset retirement obligation	3,381
Minority interest liability	7,862
Total liabilities assumed	98,632
Net assets contributed	$ 116,253

During June 2004, the entity affiliated with Mr. Icahn acquired an additional 5.7% of the outstanding shares of National Onshore from certain other stockholders at a cost of approximately $2.2 million. The $2.2 million purchase is recorded as a capital contribution from member in 2004. In December 2004, the remaining 5.3% of National Onshore shares not owned by the entity affiliated with Mr. Icahn was purchased by National Onshore at a cost of $4.1 million. The share repurchase is reflected as a purchase of membership interest in 2004. The difference between the purchase price for both acquisitions and the minority interest liability was treated as an adjustment to the historical cost basis which reduced the full cost pool.

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NOTES TO COMBINED FINANCIAL STATEMENTS (Continued)

National Offshore Effective December 31, 2004, the Period of Common Control of National Offshore, the following assets and liabilities were considered to have been contributed to the Company (amounts in thousands):

Assets contributed	
Cash and cash equivalents	$ 23,753
Accounts receivable	10,482
Drilling prepayments	2,601
Deferred tax assets, net	1,943
Other	2,051
Oil and natural gas properties	128,673
Restricted deposits	23,519
Deferred taxes	592
Total assets	193,614
Liabilities assumed	
Accounts payable	11,235
Accounts payable affiliate	555
Current portion of note payable to affiliate	5,429
Prepayments from partners	652
Accrued interest affiliates	288
Income tax payable affiliate	156
Accounts payable revenue	716
Accounts payable other	10
Derivative financial instruments	903
Note payable to affiliate net of current maturities	32,571
Asset retirement obligation	49,538
Total liabilities assumed	102,053
Net assets contributed	$ 91,561

5. Acquisitions

In March 2005, the Company purchased an additional interest in Longfellow Ranch for $31.9 million.

In October 2005, the Company executed a purchase and sale agreement to acquire Minden Field assets near its existing production properties in East Texas. This acquisition consists of 3,500 acres with 17 producing wells and numerous drilling opportunities. The purchase price was approximately $85.0 million, which was subsequently reduced to $82.3 million after purchase price adjustments, and the transaction closed on November 8, 2005.

6. Sale of West Delta Properties

In March 2005, the Company sold its rights and interest in West Delta 52, 54, and 58 to a third party in exchange for the assumption of existing future asset retirement obligations on the properties and a cash payment of $0.5 million. The estimated fair value of the asset retirement obligations assumed by the purchaser

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NOTES TO COMBINED FINANCIAL STATEMENTS (Continued)

was approximately $16.8 million. In addition, the Company transferred to the purchaser approximately $4.7 million in an escrow account that the Company had funded relating to the asset retirement obligations on the properties. The full cost pool was reduced by approximately $11.6 million and no gain or loss was recognized on the transaction.

7. Investments/Note Receivable

In January 2002, the Company acquired stock valued at $49.95 million, which was sold at a gain of $8.7 million in February 2002. In an unrelated transaction, the Company completed a short sale of stock in November 2002 for $10.4 million. At December 31, 2002, this short sale position remained open and the mark-to-market value of such stock resulted in an unrealized loss of $0.3 million. In January 2003, the Company settled this position and recorded a loss of $1.0 million on the transaction.

In October 2003, the Company committed to an investment of $6.0 million in PetroSource Energy Company, LLC (PetroSource). The Company s commitment was to acquire 24.8% of the outstanding stock for a price of $3.0 million and to advance $3.0 million as a subordinated loan bearing 6% interest due in six years. The Company initially purchased $1.8 million in stock and funded $1.8 million of the loan in October 2003. In February 2004, the Company purchased an additional $1.2 million of stock and funded the remaining $1.2 million loan commitment. PetroSource is in the business of selling CO(2) and also owns pipelines and compressor stations for delivery purposes. During 2004, PetroSource sold additional equity shares which reduced the Company s ownership to 20.63%. The Company recorded losses of $0.1 million, $0.5 million, and $1.1 million in 2003, 2004 and 2005, respectively, as a result of accounting for the PetroSource investment under the equity method. During 2005, the Company invested an additional $0.5 million in PetroSource stock. In December 2005, the Company sold its entire investment in PetroSource, including the subordinate loan, for total proceeds of $10.5 million and recorded a gain of $5.5 million.

In April 2002, the Company entered into a revolving credit commitment to extend advances to an unrelated third party. Under the terms of the revolving credit arrangement, the Company agreed to make advances from time to time, as requested by the unrelated third party and subject to certain limitations, in an amount up to $5.0 million. Advances made under the revolving credit commitment bear interest at prime rate plus 2% and are collateralized by inventory and receivables. As of December 31, 2004, the Company determined that a portion of the total outstanding advances of $1.3 million had been impaired and recorded a loss of $0.8 million. As of December 31, 2005, the Company determined that the majority of the total outstanding advance of $1.27 million had been impaired and recorded an additional loss of $0.5 million bringing the total allowance to $1.26 million. The loss is recorded as an impairment of note receivable and is included in general and administrative expenses.

8. Restricted Deposits

In connection with the National Offshore transaction, the Company acquired restricted deposits aggregating $23.5 million. The restricted deposits represent bank trust and escrow accounts required to be set up by surety bond underwriters and certain former owners of National Offshore s offshore properties. In accordance with requirements of the U.S. Department of Interior s Minerals Management Service (MMS), National Offshore was required to put in place surety bonds and/or escrow agreements to provide satisfaction of its eventual responsibility to plug and abandon wells and remove structures when certain offshore fields are no longer in use. As part of National Offshore s agreement with the surety bond underwriter or the former owners of the particular fields, bank trust and escrow accounts were set up and funded based on the terms of the escrow agreements. Certain amounts are required to be paid upon receipt of proceeds from production.

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The restricted deposits include the following:

1. A $4.2 million escrow account for the East Breaks 109 and 110 fields set up in favor of the surety bond underwriter who provides a surety bond to the MMS. The escrow account is fully funded as of December 31, 2005.

2. A $6.9 million escrow account for the East Breaks 165 and 209 fields set up in favor of the surety bond underwriter who provides a surety bond to the former owners of the fields and the MMS. The escrow account is fully funded as of December 31, 2005.

3. A $4.1 million escrow account set up in favor of a major oil company. The Company is required to make additional deposits to the escrow account in an amount equal to 10% of the net cash flow (as defined in the escrow agreement) from the properties that were acquired from the major oil company.

4. A $3.8 million escrow account that was required to be set up by the bankruptcy settlement proceedings of National Offshore. The Company is required to make monthly deposits based on cash flows from certain wells, as defined in the agreement.

5. A $5.3 million escrow account required to be set up by the MMS relating to East Breaks properties. The Company is required to make quarterly deposits to the escrow account of $0.8 million. Additionally, for some of the East Break properties, the Company will be required to deposit additional funds in the East Break escrow accounts, representing the difference between the required escrow deposit under the surety bond and actual escrow deposit balance at various points in time in the future. Aggregate payments to the East Breaks escrow accounts are as follows (in thousands):

Year Ended December 31,	
2006	$ 3,200
2007	6,100
2008	3,200
2009	3,200
2010	5,000
Thereafter	4,000
	$ 24,700

9. Debt

The Company s debt consists of credit facilities, notes payable, note payable to affiliates and senior notes payable to affiliates.

Credit Facilities

The Operating LLC Credit Facility

On December 29, 2003, Holding LLC entered into a Credit Agreement (the Mizuho Facility) with certain commercial lending institutions, including Mizuho Corporate Bank, Ltd. as the Administrative Agent and the Bank of Texas, N.A. and the Bank of Nova Scotia as Co-Agents.

The Credit Agreement provided for a loan commitment amount of up to $145.0 million and a letter of credit commitment of up to $15 million (provided, the outstanding aggregate amount of the unpaid borrowings, plus the aggregate undrawn face amount of all outstanding letters of credit shall not exceed the borrowing base under the Credit Agreement). The Credit Agreement provided further that the amount available to the

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Operating LLC at any time was subject to certain restrictions, covenants, conditions and changes in the borrowing base calculation. In partial consideration of the loan commitment amount, Operating LLC has pledged a continuing security interest in all of its oil and natural gas properties and its equipment, inventory, contracts, fixtures and proceeds related to its oil and natural gas business.

At Operating LLC s option, interest on borrowings under the Credit Agreement bear interest at a rate based upon either the prime rate or the LIBOR rate plus, in each case, an applicable margin that, in the case of prime rate loans, can fluctuate from 0.75% to 2.50% per annum. Fluctuations in the applicable interest rate margins are based upon Operating LLC s total usage of the amount of credit available under the Credit Agreement, with the applicable margins increasing as Operating LLC s total usage of the amount of the credit available under the Credit Agreement increases.

At the closing of the Credit Agreement, Operating LLC borrowed $43.8 million to repay $42.9 million owed by Operating LLC to an affiliate of Mr. Icahn under the secured loan arrangement which was then terminated and to pay administrative fees in connection with this borrowing. Approximately $1.4 million of loan issuance costs was capitalized in connection with the closing of this transaction.

The Credit Agreement required, among other things, semiannual engineering reports covering oil and natural gas properties, and maintenance of certain financial ratios, including the maintenance of a minimum interest coverage, a current ratio, and a minimum tangible net worth.

NEG Oil & Gas LLC Senior Secured Revolving Credit Facility

On December 22, 2005, the Company entered into a credit agreement, dated as of December 20, 2005, with Citicorp USA, Inc., as administrative agent, Bear Stearns Corporate Lending Inc., as syndication agent, and other lender parties thereto (the NEG Credit Facility). The NEG Credit Facility is secured by substantially all the assets of the Company and its subsidiaries, has a five-year term and permits payments and re-borrowings, subject to a borrowing base calculation based on the proved oil and gas reserves of the Company and its subsidiaries. Under the NEG Credit Facility, the Company will be permitted to borrow up to $500 million, and the initial borrowing base is set at $335 million. The Company used a portion of the initial $300 million funding under the NEG Credit Facility to purchase the Mizuho Facility. On a combined basis, the Mizuho Facility is no longer outstanding.

In consideration of each lender s commitment to make loans under the NEG Credit Facility, the Company is required to pay a quarterly commitment fee ranging from 0.375% to 0.50% of the available borrowing base. Commitment fees are based upon the facility utilization levels.

At the Company s option, borrowings under the NEG Credit Facility bear interest at Base Rate or Euro Dollar Rate, as defined in the borrowing agreement, plus, in each case, an applicable margin that, in the case of Base Rate loans, can fluctuate from 0.00% to 0.75% per annum, and, in the case of Euro Dollar loans, can fluctuate from 1.00% to 1.75% per annum. Fluctuations in the applicable interest rate margins are based upon the Company s total usage of the amount of credit available under the NEG Credit Facility, with the applicable margins increasing as the Company s total usage of the amount of the credit available under the NEG Credit Facility increases. Base Rate and Euro Dollar Rate fluctuate based upon Prime rate or LIBOR, respectively. At December 31, 2005, the interest rate on the outstanding amount under the credit facility was 6.44% and $14.6 million was available for future borrowings.

NEG Credit Facility agreement requires, among other things, semiannual engineering reports covering oil and natural gas properties, limitation on distributions, and maintenance of certain financial ratios, including maintenance of leverage ratio, current ratio and a minimum tangible net worth. The Company was in compliance with all covenants at December 31, 2005.

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In addition to purchasing the Mizuho Facility, the Company used the proceeds from the NEG Credit Facility to (1) repay a loan of approximately $85 million by AREP used to purchase properties in the Minden Field; (2) pay a distribution of $78.0 million, and (3) pay transaction costs.

Notes Payable

Notes payable consist of the following (amounts in thousands):

	2004	2005
Notes payable to various prior creditors of National Onshore in settlement of bankruptcy claims. The notes are generally payable over a 30 month period with a stated interest rate of 6%; however, the notes have been discounted to an effective rate of 10%	$ 4,320	$ 2,503
Note payable asset acquisition	83	
Total	4,403	2,503
Less Current maturities	(1,761)	(2,503)
	$ 2,642	$

Notes Payable to Affiliates

Notes payable to affiliates consist of the following (amounts in thousands):

	2004	2005
In connection with the National Onshore plan of reorganization, on August 28, 2003, National Onshore entered into a note agreement with an affiliate of Mr. Icahn. The note is a term loan in the amount of $32.5 million and bears interest at a rate of 10% per annum. Interest is payable semi-annually. Annual principal payments in the amount of $5 million are due on the first through fourth anniversary dates of the note with the final principal payment of $12.5 million due on the fifth anniversary date. The note is secured by substantially all of the assets of National Onshore. On December 6, 2004, AREP purchased the note from the affiliate of Mr. Icahn and on June 30, 2005, contributed the note, excluding accrued and unpaid interest, to the Company	$ 27,500	$
Note payable to an affiliate of Mr. Icahn arising from the bankruptcy plan of National Offshore. The note bears interest at Wall Street Journal LIBOR plus 4% (6.35% at December 31, 2004) and is payable in quarterly principal installments of $1.4 million plus	38,000	

interest commencing March 31, 2005. The loan was secured by substantially all of the assets of National Offshore. On December 6, 2004, the note was purchased by AREP from an affiliate of Mr. Icahn and on June 30, 2005, the note, excluding accrued and unpaid interest was contributed to the Company				
Total		65,500		
Less Current maturities		(10,429)		
	$	55,071	$	

During 2005, the Company borrowed additional $25.0 million from AREP and repaid $1.4 million. The remaining outstanding balance of $23.6 million, excluding accrued and unpaid interest, along with notes payable detailed above, were contributed to the Company.

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Advance from Affiliate

During 2005, AREP made unsecured non-interest bearing advance of $49.8 million, payable on demand, to fund their drilling programs as well as to fund derivative contract deposits, of which $39.8 million were outstanding at December 31, 2005. The outstanding balance was repaid in January 2006.

Deferred Loan Costs

The Company capitalized approximately $1.5 million in external direct costs associated with the Credit Agreement which was being amortized (approximately $0.05 million per month) as deferred loan costs. Upon execution of the NEG Credit Facility, the Company expensed the unamortized deferred loan cost of $0.4 million relating to the Mizuho Facility in December 2005.

Additionally, the Company capitalized $4.7 million in external direct costs associated with the NEG Credit Facility executed on December 22, 2005. The deferred costs will be amortized over the term of the facility as additional interest expense.

Five Year Maturities

Aggregate annual maturities of debt for fiscal years 2006 to 2010 are as follows: 2006 $42.3 million; 2007 $0 million; 2008 $0; 2009 $0; 2010 $300.0 million.

10. Income Taxes

National Onshore and National Offshore were organized as corporations until their respective acquisitions by NEG Oil & Gas LLC, and were subject to corporate taxes up until the date of acquisition as part of a tax sharing agreement with the Starfire, Inc. consolidated group. The Company accounts for income taxes of National Onshore and National Offshore according to Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes (SFAS 109). SFAS 109 requires the recognition of deferred tax assets, net of applicable reserves, related to net operating loss carryforwards and certain temporary differences. The standard requires recognition of a future tax benefit to the extent that realization of such benefit is more likely than not. Otherwise, a valuation allowance is applied.

The (provision) benefit for U.S. federal income taxes attributable to continuing operations is as follows (amounts in thousands):

	Year Ended December 31,		
	2003	2004	2005
Current	$ (2,338)	$ (404)	$ (3)

Deferred	14,953	144	2,935
	$ 12,615	$ (260)	$ 2,932

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The tax effect of significant differences representing net deferred tax assets (the difference between financial statement carrying values and the tax basis of assets and liabilities) for the Company is as follows (in thousands):

	December 31, 2004	
	National Onshore	National Offshore
Deferred tax assets related to:		
Net operating loss carryforwards	21,434	14,917
AMT and other credit carryforwards	1,288	610
Property, plant & equipment undeveloped properties	64,945	
Other, net	2,217	8,289
	89,884	23,816
Less valuation allowance	(49,793)	
Subtotal	40,091	23,816
Less current portion		(1,943)
Deferred tax assets	$ 40,091	$ 21,873
Deferred tax liabilities related to:		
Property, plant & equipment developed properties	$ (52,890)	$ (21,281)
Deferred tax liabilities	(52,890)	(21,281)
Net deferred tax asset/(liabilities)	$ (12,799)	$ 592

At December 31, 2004, after the filing of prior years amended returns, TransTexas Gas Corporation (TransTexas) had net operating loss carryforwards of approximately $150.0 million, which begin expiring in 2020. On April 6, 2005, TransTexas merged into National Onshore, a limited partnership, resulting in the treatment of an asset sale for tax purposes and subsequent liquidation into its parent company. Pursuant to the asset sale, TransTexas utilized approximately $75.0 million of its net operating loss carryforwards on its final corporate tax return and the remainder transferred to its parent company in the liquidation. Additionally, upon the TransTexas merger into National Onshore, the net deferred tax liabilities of approximately $9.9 million were credited to equity, in accordance with SFAS 109.

At December 31, 2004, Panaco, Inc. (Panaco) had net operating loss carryforwards available for federal income tax purposes of approximately $39.2 million, which begin expiring in 2019. On June 30, 2005, pursuant to the Panaco purchase agreement, Panaco merged into National Offshore LP. The purchase was a non-taxable transaction resulting in the net operating loss carryforwards remaining with the former Panaco stockholders. Additionally, in accordance with SFAS 109, for financial reporting purposes, the net deferred tax assets of approximately $2.6 million were debited to equity.

NEG OIL & GAS LLC AND SUBSIDIARIES, EXCLUDING NATIONAL ENERGY GROUP, INC. AND THE 103/4% SENIOR NOTES DUE FROM NATIONAL ENERGY GROUP INC., BUT INCLUDING NATIONAL ENERGY GROUP INC. S 50% MEMBERSHIP INTEREST IN NEG HOLDING LLC

NOTES TO COMBINED FINANCIAL STATEMENTS (Continued)

The reconciliation of income taxes computed at the U.S. federal statutory tax rates to the provision (benefit) for income taxes on income from continuing operations is as follows:

	Year Ended December 31,		
	2003	**2004**	**2005**
Federal statutory rate	35.0%	35.0%	35.0%
Income not subject to taxation	(39.0)%	(31.2)%	(44.0)%
Valuation allowance on deferred tax assets	(45.3)%	(3.0)%	
Other	0.8%		(0.2)%
	(48.5)%	0.8%	(9.2)%

11. Commitments and Contingencies

During 2000 and 2001 National Energy Group entered into several hedge contracts with Enron North America Corp (Enron NAC). In 2001 Enron Corporation and many Enron Corporation affiliates and subsidiaries, including Enron NAC filed for protection under Chapter 11 of the US bankruptcy code. The derivative contracts were subsequently contributed to Holding LLC and then to Operating LLC. Operating LLC has filed a claim for damages in the Enron NAC bankruptcy proceeding and our designee has been appointed as a representative to the official committee of unsecured creditors. The Company s claim is unsecured. During 2005, we received $0.2 million in partial settlement of our claims which was recorded in interest income and other. In April 2006, we received an additional payment of $1.0 million and we should receive additional distributions from the Enron bankruptcy proceeding in accordance with its plan of reorganization. We will record such additional payments, if any, when the amounts are known.

Other than routine litigation incidental to its business operations which are not deemed by the Company to be material, there are no additional legal proceedings in which the Company, is a defendant.

Environmental Matters

The Company s operations and properties are subject to extensive federal, state, and local laws and regulations relating to the generation, storage, handling, emission, transportation, and discharge of materials into the environment. Permits are required for various of the Company s operations, and these permits are subject to revocation, modification, and renewal by issuing authorities. The Company s operations are also subject to federal, state, and local laws and regulations that impose liability for the cleanup or remediation of property which has been contaminated by the discharge or release of hazardous materials or wastes into the environment. Governmental authorities have the power to enforce compliance with their regulations, and violations are subject to fines or injunctions, or both. The Company believes that it is in material compliance with applicable environmental laws and regulations. Noncompliance with such laws and regulations could give rise to compliance costs and administrative penalties. Management does not anticipate that the Company will be required in the near future to expend amounts that are material to the financial condition or operations of the Company by reason of environmental laws and regulations, but because such laws and regulations are frequently changed and, as a result, may impose increasingly strict requirements, the Company is unable to predict the ultimate cost of complying with such laws and regulations.

12. Asset Retirement Obligation

In June 2001, the Financial Accounting Standards Board (FASB) issued Statements of Financial Accounting Standards (SFAS) No. 143, *Accounting for Asset Retirement Obligations* (SFAS 143). The Company adopted SFAS 143 on January 1, 2003 and recorded an abandonment obligation of $3.0 million,

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NOTES TO COMBINED FINANCIAL STATEMENTS (Continued)

increased oil and natural gas properties $4.9 million and recorded a cumulative transition gain of $1.9 million. SFAS No. 143 requires the Company to record the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development, and/or normal use of the assets. It also requires the Company to record a corresponding asset that is depreciated over the life of the asset. Subsequent to the initial measurement of the asset retirement obligation, the obligation will be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The ARO assets are recorded on the balance sheet as part of the Company s full cost pool and are included in the amortization base for the purposes of calculating depreciation, depletion and amortization expense. For the purpose of calculating the ceiling test, the future cash outflows associated with settling the ARO liability are excluded from the computation of the discounted present value of estimated future net revenues.

The following is a rollforward of the abandonment obligation as of December 31, 2004 and 2005 (amounts in thousands).

Balance as of January 1, 2004	$ 6,745
Add: Accretion	593
Drilling additions	216
Panaco	49,538
Less: Revisions	(251)
Settlements	(24)
Dispositions	(293)
Balance as of December 31, 2004	$ 56,524
Add: Accretion	$ 3,019
Drilling additions	2,067
Less: Revisions	(2,813)
Settlements	(431)
Dispositions	(17,138)
Balance as of December 31, 2005	$ 41,228

13. Severance tax refund

During 2002, the Company applied for high-cost/tight-gas formation designation from the Railroad Commission of Texas for a portion of the Company s South Texas production. For qualifying wells, high-cost/tight-gas formation production is either exempt from tax or taxed at a reduced rate until certain capital costs are recovered. The designation was approved in 2004 and was retroactive to the date of initial production. During 2004, the Company recognized a gain of approximately $4.5 million for the refund of prior period severance taxes, for which the

Company s severance tax payments were reduced by approximately $3.2 million. At December 31, 2004, accounts receivable includes $1.3 million in prior period severance tax refunds all of which was realized as reductions in severance tax payments in 2005.

NEG OIL & GAS LLC AND SUBSIDIARIES, EXCLUDING NATIONAL ENERGY GROUP, INC. AND THE 103/4% SENIOR NOTES DUE FROM NATIONAL ENERGY GROUP INC., BUT INCLUDING NATIONAL ENERGY GROUP INC. S 50% MEMBERSHIP INTEREST IN NEG HOLDING LLC

NOTES TO COMBINED FINANCIAL STATEMENTS (Continued)

14. Crude Oil and Natural Gas Producing Activities

Costs incurred in connection with the exploration, development, and exploitation of the Company s crude oil and natural gas properties for the years ended December 31, 2003, 2004 and 2005 are as follows (amounts in thousands except depletion rate per Mcfe):

	Year Ended December 31,		
	2003	2004	2005
Acquisition of properties	$	$	$ 114,244
Properties contributed by member	186,289	128,673	
Exploration costs	6,950	62,209	75,357
Development costs	34,012	52,765	124,305
Depletion rate per Mcfe	$ 1.85	$ 2.11	$ 2.33

As of December 31, 2004 and 2005, all capitalized costs are included in the full cost pool and are subject to amortization.

Revenues from individual purchasers that exceed 10% of crude oil and natural gas sales are as follows:

	Year Ended December 31,		
	2003	2004	2005
Plains All American	$ 15,667	$ 19,857	$ 41,345
Duke Energy	10,572	33,958	44,850
Kinder Morgan	5,787	18,005	14,402
Crosstex Energy Services, Inc.	9,228	5,081	22,790
Riata Energy, Inc.	30,672	29,846	52,300
Seminole Energy Services	7,216	19,568	27,315
Louis Dreyfus			26,790

15. Supplementary Crude Oil and Natural Gas Reserve Information (Unaudited)

The revenues generated by the Company s operations are highly dependent upon the prices of, and demand for, oil and natural gas. The price received by the Company for its oil and natural gas production depends on numerous factors beyond the Company s control, including seasonality, the condition of the U.S. economy, foreign imports, political conditions in other oil and natural gas producing countries, the actions of the Organization of Petroleum Exporting Countries and domestic governmental regulations, legislation and policies.

The Company has made ordinary course capital expenditures for the development and exploitation of oil and natural gas reserves, subject to economic conditions. The Company has interests in crude oil and natural gas properties that are principally located onshore in Texas, Louisiana, Oklahoma, Arkansas, Gulf Coast and offshore in the Gulf of Mexico. The Company does not own or lease any crude oil and natural gas properties outside the United States.

In 2003 and 2004, estimates of the Company s reserves and future net revenues were prepared by Netherland, Sewell & Associates, Inc., Prator Bett, LLC and DeGolyer and MacNaughton. In 2005, estimates of the Company s reserves and future net revenues were prepared by Netherland, Sewell & Associates, Inc. and DeGolyer and MacNaughton. Estimated proved net recoverable reserves as shown below include only those quantities that can be expected to be recoverable at prices and costs in effect at the balance sheet dates under existing regulatory practices and with conventional equipment and operating methods.

NEG OIL & GAS LLC AND SUBSIDIARIES, EXCLUDING NATIONAL ENERGY GROUP, INC. AND THE 103/4% SENIOR NOTES DUE FROM NATIONAL ENERGY GROUP INC., BUT INCLUDING NATIONAL ENERGY GROUP INC. S 50% MEMBERSHIP INTEREST IN NEG HOLDING LLC

NOTES TO COMBINED FINANCIAL STATEMENTS (Continued)

In 2003, extension and discovery reserve additions were largely impacted by the successful drilling on the Longfellow Ranch. Drilling on the Longfellow Ranch in 2003 extended field producing boundaries as well as identifying deeper Caballos and Devonian reservoirs not previously captured as proved reserves. The drilling program in 2004 had continued success in the Longfellow Ranch Area extending field boundaries along with the discovery of two new fields. The East Texas Region in 2004 extended producing boundaries adding proved reserves for the Cotton Valley Reservoir. A new field discovery in the Gulf Coast area resulted in new reserves along with three extension wells. In 2005, continued drilling in the West Texas Region, Longfellow Ranch, and the East Texas Region, Cotton Valley development resulted in 86% of the added extension and discovery gas reserves. Changes in reserves associated with development drilling have been accounted for in revisions of previous estimates.

Proved developed reserves represent only those reserves expected to be recovered through existing wells. Proved undeveloped reserves include those reserves expected to be recovered from new wells on undrilled acreage or from existing wells on which a relatively major expenditure is required for recompletion.

Net quantities of proved developed and undeveloped reserves of natural gas and crude oil, including condensate and natural gas liquids, are summarized as follows:

	Crude Oil (MBbl)	Natural Gas (MMcf)
December 31, 2002	5,209	122,567
Reserves of TransTexas contributed by member	1,120	41,441
Sales of reserves in place	(25)	(744)
Extensions and discoveries	494	61,638
Revisions of previous estimates	2,344	(2,729)
Production	(976)	(15,913)
December 31, 2003	8,166	206,260
Reserves of Panaco contributed by member	5,204	25,982
Sales of reserves in place	(16)	(344)
Extensions and discoveries	524	50,226
Revisions of previous estimates	204	9,810
Production	(1,484)	(18,895)
December 31, 2004	12,598	273,039
Purchase of reserves in place	483	94,937
Sales of reserves in place	(625)	(7,426)
Extensions and discoveries	743	79,592
Revisions of previous estimates	495	17,015
Production	(1,790)	(28,107)

December 31, 2005	11,904	429,050
Proved developed reserves:		
December 31, 2003	6,852	125,765
December 31, 2004	8,955	151,452
December 31, 2005	8,340	200,520

NEG OIL & GAS LLC AND SUBSIDIARIES, EXCLUDING NATIONAL ENERGY GROUP, INC. AND THE 103/4% SENIOR NOTES DUE FROM NATIONAL ENERGY GROUP INC., BUT INCLUDING NATIONAL ENERGY GROUP INC. S 50% MEMBERSHIP INTEREST IN NEG HOLDING LLC

NOTES TO COMBINED FINANCIAL STATEMENTS (Continued)

Reservoir engineering is a subjective process of estimating the volumes of underground accumulations of oil and natural gas which cannot be measured precisely. The accuracy of any reserve estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Reserve estimates prepared by other engineers might differ from the estimates contained herein. Results of drilling, testing, and production subsequent to the date of the estimate may justify revision of such estimate. Future prices received for the sale of oil and natural gas may be different from those used in preparing these reports. The amounts and timing of future operating and development costs may also differ from those used. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

The following is a summary of a standardized measure of discounted net cash flows related to the Company s proved crude oil and natural gas reserves. For these calculations, estimated future cash flows from estimated future production of proved reserves were computed using crude oil and natural gas prices as of the end of each period presented. Future development, production and net asset retirement obligations attributable to the proved reserves were estimated assuming that existing conditions would continue over the economic lives of the individual leases and costs were not escalated for the future.

The Company cautions against using the following data to determine the fair value of its crude oil and natural gas properties. To obtain the best estimate of fair value of the crude oil and natural gas properties, forecasts of future economic conditions, varying discount rates, and consideration of other than proved reserves would have to be incorporated into the calculation. In addition, there are significant uncertainties inherent in estimating quantities of proved reserves and in projecting rates of production that impair the usefulness of the data.

The standardized measure of discounted future net cash flows relating to proved crude oil and natural gas reserves are summarized as follows (amounts in thousands):

	December 31,	
	2004	2005
Future cash inflows	$ 2,203,900	$ 4,891,094
Future production costs	(488,473)	(1,029,393)
Future development costs	(347,619)	(527,399)
Future income tax expense	(32,979)	
Future net cash flows	1,334,829	3,334,302
10% annual discount for estimated timing of cash flows	(563,549)	(1,562,242)
Standardized measure of discounted future net cash flows	$ 771,280	$ 1,772,060

NEG OIL & GAS LLC AND SUBSIDIARIES, EXCLUDING NATIONAL ENERGY GROUP, INC. AND THE 103/4% SENIOR NOTES DUE FROM NATIONAL ENERGY GROUP INC., BUT INCLUDING NATIONAL ENERGY GROUP INC. S 50% MEMBERSHIP INTEREST IN NEG HOLDING LLC

NOTES TO COMBINED FINANCIAL STATEMENTS (Continued)

The following are the principal sources of change in the standardized measure of discounted future net cash flows (amounts in thousands):

	Year Ended December 31,		
	2003	**2004**	**2005**
Beginning of Period	$ 310,632	$ 613,752	$ 771,280
Purchases of reserves			415,208
Contribution of reserves by member	101,804	75,239	
Sales of reserves in place	(2,476)	(1,375)	(34,820)
Sales and transfers of crude oil and natural gas produced, net of production costs	(74,186)	(130,640)	(205,838)
Net changes in prices and production costs	76,655	16,686	408,909
Development costs incurred during the period and changes in estimated future development costs	(76,545)	(89,491)	(150,639)
Extensions and discoveries, less related costs	211,324	193,022	411,092
Income taxes			24,097
Revisions of previous quantity estimates	37,718	31,730	68,937
Accretion of discount	34,457	62,050	77,128
Changes in production rates (timing) and other	(5,631)	307	(13,294)
Net change	303,120	157,528	1,000,780
End of Period	$ 613,752	$ 771,280	$ 1,772,060

During recent years, there have been significant fluctuations in the prices paid for crude oil in the world markets. The net weighted average prices of crude oil and natural gas at December 31, 2003, 2004 and 2005, used in the above table were $29.14 and $41.80 and $57.28 per barrel of crude oil, respectively, and $5.89, $5.93 and $9.59 per thousand cubic feet of natural gas, respectively.

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NEG OIL & GAS LLC AND SUBSIDIARIES, EXCLUDING NATIONAL ENERGY GROUP, INC. AND THE 103/4% SENIOR NOTES DUE FROM NATIONAL ENERGY GROUP, INC., BUT INCLUDING NATIONAL ENERGY GROUP INC. S 50% MEMBERSHIP INTEREST IN NEG HOLDING LLC

COMBINED BALANCE SHEETS AS OF DECEMBER 31, 2005 AND SEPTEMBER 30, 2006

	December 31, 2005	September 30, 2006 (Unaudited)
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 102,322	$ 26,362
Accounts receivable, net	53,378	53,436
Notes receivable	10	9
Drilling prepayments	3,281	3,755
Derivative financial instruments		14,158
Other	9,798	5,788
Total current assets	168,789	103,508
Oil and gas properties, at cost (full cost method)	1,229,923	1,409,776
Accumulated depreciation, depletion and amortization	(488,560)	(562,635)
Net oil and gas properties	741,363	847,141
Other property and equipment	6,029	6,232
Accumulated depreciation	(4,934)	(5,173)
Net other property and equipment	1,095	1,059
Restricted deposits	24,267	30,713
Derivative financial instruments		15,787
Other assets	4,842	8,296
Total assets	$ 940,356	$ 1,006,504
LIABILITIES AND MEMBER S EQUITY		
Current Liabilities:		
Accounts payable	$ 18,105	$ 20,058
Accounts payable revenue	11,454	9,759
Accounts payable affiliates	1,660	1,569
Current portion of notes payable	2,503	
Advance from affiliate	39,800	
Prepayments from partners	121	823
Accrued interest	162	61
Accrued interest affiliates	2,194	2,194
Income tax payable affiliate	2,749	2,749

Derivative financial instruments	68,039	
Total current liabilities	146,787	37,213
Commitments and contingencies		
Credit facility	300,000	300,000
Gas balancing	1,108	1,108
Derivative financial instruments	17,893	
Other liabilities	250	250
Deferred income tax liability		2,128
Asset retirement obligation	41,228	47,609
Total liabilities	507,266	388,308
Member s equity	433,090	618,196
Total liabilities and member s equity	$ 940,356	$ 1,006,504

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

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NEG OIL & GAS LLC AND SUBSIDIARIES, EXCLUDING NATIONAL ENERGY GROUP, INC. AND THE 103/4% SENIOR NOTES DUE FROM NATIONAL ENERGY GROUP, INC., BUT INCLUDING NATIONAL ENERGY GROUP INC. S 50% MEMBERSHIP INTEREST IN NEG HOLDING LLC

COMBINED STATEMENTS OF OPERATIONS
Nine Month Periods Ended September 30, 2005 and 2006

	Nine Months Ended September 30, 2005	2006
	(Unaudited) (In thousands)	
Revenues:		
Oil and gas sales gross	$ 193,633	$ 208,800
Unrealized derivatives (losses) gains	(111,631)	115,877
Oil and gas revenues net	82,002	324,677
Plant revenues	4,707	5,799
Total revenues	86,709	330,476
Costs and expenses:		
Lease operating	19,632	26,817
Transportation and gathering	3,764	3,441
Plant and field operations	2,644	3,270
Production and ad valorem taxes	11,184	8,948
Depreciation, depletion and amortization	65,756	74,408
Accretion of asset retirement obligation	2,290	2,112
General and administrative	10,651	10,281
Total costs and expenses	115,921	129,277
Operating income (loss)	(29,212)	201,199
Interest expense	(4,856)	(16,738)
Interest expense affiliate	(3,047)	
Interest income and other	185	4,788
Income (loss) before income taxes	(36,930)	189,249
Income tax benefit (expense)	2,932	(2,143)
Net income (loss)	$ (33,998)	$ 187,106

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

NEG OIL & GAS LLC AND SUBSIDIARIES, EXCLUDING NATIONAL ENERGY GROUP, INC. AND THE 103/4% SENIOR NOTES DUE FROM NATIONAL ENERGY GROUP, INC., BUT INCLUDING NATIONAL ENERGY GROUP INC. S 50% MEMBERSHIP INTEREST IN NEG HOLDING LLC

COMBINED STATEMENTS OF CASH FLOWS
Nine Month Periods Ended September 30, 2005 and 2006

	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2006
	(Unaudited) (In thousands)	
Operating activities:		
Net income (loss)	$ (33,998)	$ 187,106
Noncash adjustments:		
Deferred income tax expense (benefit)	(2,932)	2,128
Depreciation, depletion and amortization	65,756	74,408
Unrealized derivative losses (gains)	111,631	(115,877)
Accretion of asset retirement obligation	2,290	2,112
Amortization of note discount	66	27
Equity in loss on investment	917	
Interest income-restricted deposits	(265)	(616)
Amortization of note costs	527	773
Gain on sale of assets	(9)	(2)
Changes in operating assets and liabilities:		
Accounts receivable	(9,270)	(212)
Drilling prepayments	(1,616)	(475)
Derivative deposit	(64,068)	
Other assets	2,369	3,920
Accounts payable and accrued liabilities	(7,605)	1,013
Net cash provided by operating activities	63,793	154,305
Investing activities:		
Acquisition, exploration, and development costs	(183,479)	(175,619)
Proceeds from sales of oil and gas properties	679	37
Purchases of furniture, fixtures and equipment	(398)	(293)
Equity investment	(454)	
Investment in restricted deposits	(3,538)	(5,832)
Net cash used in investing activities	(187,190)	(181,707)
Financing activities:		
Debt issuance costs		(573)
Guaranteed payment to member	(7,989)	(7,989)
Equity contribution		7,989
Proceeds from/repayment of affiliate borrowings	73,443	(39,800)

Dividend payment to member				(2,000)
Proceeds from credit facility		59,100		
Principal payments on debt		(1,554)		(2,530)
Deferred equity costs				(3,655)
Net cash provided by (used in) financing activities		123,000		(48,558)
Decrease in cash and cash equivalents		(397)		(75,960)
Cash and cash equivalents at beginning of period		30,846		102,322
Cash and cash equivalents at end of period	$	30,449	$	26,362
Supplemental cash flow information:				
Cash paid for interest	$	13,205	$	16,052

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

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NEG OIL & GAS LLC AND SUBSIDIARIES, EXCLUDING NATIONAL ENERGY GROUP, INC. AND THE 103/4% SENIOR NOTES DUE FROM NATIONAL ENERGY GROUP, INC., BUT INCLUDING NATIONAL ENERGY GROUP INC. S 50% MEMBERSHIP INTEREST IN NEG HOLDING LLC

COMBINED STATEMENT OF CHANGES IN TOTAL MEMBER S EQUITY
Nine Month Period Ended September 30, 2006
(2006 Amounts Unaudited)

		(In thousands)
Total member s equity December 31, 2005	$	433,090
Dividend distribution		(2,000)
Equity contribution		7,989
Guaranteed payment to member		(7,989)
Net income		187,106
Total member s equity September 30, 2006	$	618,196

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

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NEG OIL & GAS LLC AND SUBSIDIARIES, EXCLUDING NATIONAL ENERGY GROUP, INC. AND THE 103/4% SENIOR NOTES DUE FROM NATIONAL ENERGY GROUP, INC., BUT INCLUDING NATIONAL ENERGY GROUP INC. S 50% MEMBERSHIP INTEREST IN NEG HOLDING LLC

NOTES TO COMBINED FINANCIAL STATEMENTS
September 30, 2006
(Unaudited)

1. Organization, Basis of Presentation and Background

The accompanying combined financial statements present NEG Oil & Gas LLC and subsidiaries excluding National Energy Group, Inc., and the 103/4% Senior Notes due from National Energy Group, Inc., but including National Energy Group, Inc. s 50% interest in NEG Holding LLC (collectively the Company). The Company is an oil and gas exploration and production company engaged in the exploration, development, production and operations of natural gas and oil properties, primarily located in Texas, Oklahoma, Arkansas and Louisiana (both onshore and in the Gulf of Mexico).

NEG Oil & Gas, LLC is wholly-owned by American Real Estate Holdings Limited Partnership (AREH). AREH is 99% owned by American Real Estate Partners, L.P. (AREP). AREP is a publicly traded limited partnership that is majority owned by Mr. Carl C. Icahn.

NEG Oil & Gas LLC was formed on December 2, 2004 to hold the oil and gas investments of the Company s ultimate parent company, AREP. As of September 30, 2006 the Company s assets and operations consist of the following:

A 50.01% ownership interest in National Energy Group, Inc (National Energy Group), a publicly traded oil and gas management company. National Energy Group s principal asset consists of its 50% membership interest in NEG Holding LLC (Holding, LLC);

$148.6 million principal amount of 103/4% Senior Notes due from National Energy Group (the 103/4% Senior Notes).

A 50% managing membership interest in Holding, LLC;

The oil and gas operations of National Onshore LP; and

The oil and gas operations of National Offshore LP.

All of the above assets initially were acquired by entities owned or controlled by Mr. Icahn and subsequently acquired by AREP (through subsidiaries) in various purchase transactions. In accordance with generally accepted accounting principles, assets transferred between entities under common control are accounted for at historical cost similar to a pooling of interest and the financial statements are combined from the date of acquisition by an entity under common control. The financial statements include the results of operations, financial position and cash flows of each of the above entities since its initial acquisition by entities owned or controlled by Mr. Icahn (the Period of Common Control).

On September 7, 2006, AREP signed a letter of intent to sell NEG Oil & Gas LLC and subsidiaries, excluding National Energy Group and the 103/4% Senior Notes due from National Energy Group, but including National Energy Group s 50% interest in Holding LLC to Riata Energy, Inc., DBA Riata Energy, Inc. (Riata Energy) The combined financial statements include the entities to be sold to Riata Energy.

Basis of Presentation

The accompanying unaudited combined interim financial statements have been prepared in accordance both with accounting principles generally accepted in the United States of America for interim financial information, and Article 10 of Regulation S-X and are fairly presented. Accordingly, they do not include all of the information and footnotes required by generally accepted accounting principles for complete financial statements. In the opinion of management, these financial statements contain all adjustments, consisting of normal recurring accruals, necessary to present fairly the financial position, results of operations and cash

NEG OIL & GAS LLC AND SUBSIDIARIES, EXCLUDING NATIONAL ENERGY GROUP, INC. AND THE 103/4% SENIOR NOTES DUE FROM NATIONAL ENERGY GROUP, INC., BUT INCLUDING NATIONAL ENERGY GROUP INC. S 50% MEMBERSHIP INTEREST IN NEG HOLDING LLC

NOTES TO COMBINED FINANCIAL STATEMENTS (Unaudited) (Continued)

flows for the periods indicated. The preparation of financial statements in accordance with generally accepted accounting principles requires us to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results may differ from these estimates. Our financial data for the nine month periods ended September 30, 2005 and 2006 should be read in conjunction with our audited financial statements for the year ended December 31, 2005 including the notes thereto.

In July 2006, the FASB issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement 109 (FIN 48), which clarifies the accounting for uncertainty in tax positions taken or expected to be taken in a tax return, including issues relating to financial statement recognition and measurement. FIN 48 provides that the tax effects from an uncertain tax position can be recognized in the financial statements only if the position is more-likely-than-not of being sustained if the position were to be challenged by a taxing authority. The assessment of the tax position is based solely on the technical merits of the position, without regard to the likelihood that the tax position may be challenged. If an uncertain tax position meets the more-likely-than-not threshold, the largest amount of tax benefit that is greater than 50 percent likely of being recognized upon ultimate settlement with the taxing authority, is recorded. The provisions of FIN 48 are effective for fiscal years beginning after December 15, 2006, with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. The Company is currently evaluating the impact of adopting FIN 48 on its financial statements.

In September 2006, the SEC issued Staff Accounting Bulletin No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements (SAB 108). SAB 108 provides guidance on how to evaluate prior period financial statement misstatements for purposes of assessing their materiality in the current period. If the prior period effect is material to the current period, then the prior period is required to be corrected. Correcting prior year financial statements would not require an amendment of prior year financial statements, but such corrections would be made the next time the company files the prior year financial statements. Upon adoption, SAB 108 allows a one-time transitional cumulative effect adjustment to retained earnings for corrections of prior period misstatements required under this statement. SAB 108 is effective for fiscal years beginning after November 15, 2006. The adoption of SAB 108 is not expected to be material to the Company s consolidated financial statements.

Background

National Energy Group, Inc In February, 1999 National Energy Group was placed under involuntary, court ordered bankruptcy protection. Effective August 4, 2000 National Energy Group emerged from involuntary bankruptcy protection with affiliates of Mr. Icahn owning 49.9% of the common stock and $165 million principal amount of debt securities (Senior Notes). As mandated by National Energy Group s Plan of Reorganization, Holding LLC was formed and on September 1, 2001, National Energy Group contributed to Holding LLC all of its oil and natural gas properties in exchange for an initial membership interest in Holding LLC. National Energy Group retained $4.3 million in cash. On September 1, 2001, an affiliate of Mr. Icahn contributed to Holding LLC oil and natural gas assets, cash and a $10.9 million note receivable from National Energy Group in exchange for the remaining membership interest, which was designated the managing membership interest. Concurrently, in September, 2001, but effective as of May 2001, Holding LLC formed a 100% owned subsidiary, NEG Operating Company, LLC (Operating LLC) and contributed all of its oil and natural gas assets to Operating LLC.

In October 2003, AREP acquired all outstanding Senior Notes ($148.6 million principal amount at October 2003) and 5,584,044 shares of common stock of National Energy Group from entities affiliated with Mr. Icahn for aggregate consideration of approximately $148.1 million plus approximately $6.7 million of accrued interest on the Senior Notes. As a result of this transaction and the acquisition by AREP of additional

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NOTES TO COMBINED FINANCIAL STATEMENTS (Unaudited) (Continued)

shares of National Energy Group, AREP beneficially owned 50.01% of the outstanding stock of National Energy Group and had effective control. In June 2005, all of the stock of National Energy Group and the $148.6 million principal amount of Senior Notes owned by AREP was contributed to the Company and National Energy Group became a 50.01% owned subsidiary. The accrued, but unpaid interest on the $148.6 million principal amount of Senior Notes was retained by AREP. National Energy Group and the 103/4% Senior Notes will be retained by AREP.

NEG Holding LLC On June 30, 2005, AREP acquired the managing membership interest in Holding LLC from an affiliate of Mr. Icahn for an aggregate consideration of approximately $320 million and contributed it to the Company. The membership interest acquired constituted all of the membership interests other than the membership interest already owned by National Energy Group. The combined financial statements include the consolidation of the acquired 50% membership interest in Holding LLC, together with the 50% membership interest owned by National Energy Group. The Period of Common Control for Holding LLC began on September 1, 2001, the initial funding of Holding LLC.

The Holding LLC Operating Agreement

Holding LLC is governed by an operating agreement effective May 12, 2001, which provides for management and control of Holding LLC by the Company and distributions to National Energy Group and the Company based on a prescribed order of distributions (the Holding LLC Operating Agreement).

Order of Distributions

Pursuant to the Holding LLC Operating Agreement, distributions from Holding LLC to National Energy Group and the Company shall be made in the following order:

1. Guaranteed payments (Guaranteed Payments) are to be paid to National Energy Group, calculated on an annual interest rate of 103/4% on the outstanding priority amount (Priority Amount). The Priority Amount includes all outstanding debt owed to NEG Oil & Gas, including the amount of National Energy Group s 103/4% Senior Notes. As of December 31, 2005, the Priority Amount was $148.6 million. The Guaranteed Payments will be made on a semi-annual basis.

2. The Priority Amount is to be paid to National Energy Group. Such payment is to occur by November 6, 2006. This did not occur November 6, 2006 due to the pending transaction with Riata Energy as described above.

3. An amount equal to the Priority Amount and all Guaranteed Payments paid to National Energy Group, plus any additional capital contributions made by NEG Oil & Gas, less any distributions previously made by Holding LLC to NEG Oil & Gas, is to be paid to NEG Oil & Gas.

4. An amount equal to the aggregate annual interest (calculated at prime plus 1/2% on the sum of the Guaranteed Payments), plus any unpaid interest for prior years (calculated at prime plus 1/2% on the sum of the Guaranteed Payments), less any distributions previously made by Holding LLC to NEG Oil & Gas, is to be paid to NEG Oil & Gas.

5. After the above distributions have been made, any additional distributions will be made in accordance with the ratio of NEG Oil & Gas and National Energy Group s respective capital accounts. (Capital accounts as defined in the Holding LLC Operating Agreement.)

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Redemption Provision in the Holding LLC Operating Agreement

The Holding LLC Operating Agreement contains a provision that allows the managing member (NEG Oil & Gas), at any time, in its sole discretion, to redeem National Energy Group s membership interest in Holding LLC at a price equal to the fair market value of such interest determined as if Holding LLC had sold all of its assets for fair market value and liquidated.

Prior to closing the Riata Energy purchase transaction, AREP will cause NEG Oil & Gas to exercise the redemption provision and dividend the 103/4% Senior Notes to AREP or enter into transactions with a similar effect such that NEG Oil & Gas will own 100% of Holding LLC and no longer own the 103/4% Senior Notes receivable from National Energy Group. AREP will indemnify NEG Oil & Gas for any costs associated with the exercise of the redemption provision. The Holding LLC Operating Agreement will be cancelled.

National Onshore LP On November 14, 2002, National Onshore filed a voluntary petition for relief under Chapter 11 of the U.S. Bankruptcy Code in the United States Bankruptcy Court for the Southern District of Texas, Corpus Christi Division. National Onshore s First Amended Joint Plan of Reorganization submitted by an entity affiliated with Mr. Icahn, as modified on July 8, 2003 (the National Onshore Plan), was confirmed by the Bankruptcy Court on August 14, 2003 effective August 28, 2003.

As of the effective date of the National Onshore Plan, an entity affiliated with Mr. Icahn owned 89% of the outstanding shares of National Onshore. During June 2004, the entity affiliated with Mr. Icahn acquired an additional 5.7% of the outstanding shares of National Onshore from certain other stockholders. During December 2004, National Onshore acquired the remaining 5.3% of the outstanding shares that were not owned by an affiliate of Mr. Icahn. The difference between the purchase price for both acquisitions and the minority interest liability was treated as a purchase price adjustment which reduced the full cost pool.

On December 6, 2004, AREP purchased from an affiliate of Mr. Icahn $27.5 million aggregate principal amount, or 100%, of the outstanding term notes issued by National Onshore (the National Onshore Notes). The purchase price was $28.2 million, which equaled the principal amount of the National Onshore Notes plus accrued unpaid interest. The notes are payable annually in equal consecutive annual payments of $5.0 million, with the final installment due August 28, 2008. Interest is payable semi-annually in February and August at the rate of 10% per annum.

On April 6, 2005, AREP acquired 100% of the outstanding stock of National Onshore from entities owned by Mr. Icahn for an aggregate consideration of $180 million. The operations of National Onshore are considered to have been contributed to the Company on August 28, 2003 at a historical cost of approximately $116.3 million, representing the historical basis in the assets and liabilities of National Onshore of the entities owned by Mr. Icahn. AREP contributed The National Onshore Notes, but not the accrued and unpaid interest through the date of contribution, to the Company on June 30, 2005. The Period of Common Control of National Onshore began on August 28, 2003.

National Offshore LP On July 16, 2002, National Offshore filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court of the Southern District of Texas. On November 3, 2004, the Bankruptcy Court entered a confirmation order for the National Offshore s Plan of Reorganization (the National Offshore Plan). The National Offshore Plan became effective November 16, 2004 and National Offshore began operating as a reorganized entity. Upon emergence from bankruptcy, an entity controlled by Mr. Icahn owned 100% of the outstanding common stock of National Offshore.

On December 6, 2004, AREP purchased $38.0 million aggregate principal amount of term loans issued by National Offshore, which constituted 100% of the outstanding term loans of National Offshore from an

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affiliate of Mr. Icahn. On June 30, 2005, AREP contributed the National Offshore term loan, but not the accrued and unpaid interest through the date of contribution, to the Company.

On June 30, 2005, AREP acquired 100% of the equity of National Offshore from affiliates of Mr. Icahn for consideration valued at approximately $125.0 million. The Period of Common Control for National Offshore began on November 16, 2004 when National Offshore emerged from bankruptcy. The acquisition of National Offshore has been recorded effective December 31, 2004. The historical cost of approximately $91.6 million, representing the historical basis in the assets and liabilities of National Offshore of the affiliates of Mr. Icahn, was considered to have been contributed to the Company on December 31, 2004.

2. Management Agreements

The management and operation of Operating LLC is being undertaken by National Energy Group pursuant to the Management Agreement (the Operating LLC Management Agreement) which Operating LLC entered into with National Energy Group. However, neither National Energy Group s officers nor directors control the strategic direction of Operating LLC s oil and natural gas business, including oil and natural gas drilling and capital investments, which are controlled by the managing member of Holding LLC (NEG Oil & Gas). The Operating LLC management agreement provides that National Energy Group will manage Operating LLC s oil and natural gas assets and business until the earlier of December 15, 2006 (previously November 1, 2006, before the amendment of such agreement effective October 30, 2006) or such time as Operating LLC no longer owns any of the managed oil and natural gas properties. National Energy Group s employees conduct the day-to-day operations of Operating LLC s oil and natural gas business, and all costs and expenses incurred in the operation of the oil and natural gas properties are borne by Operating LLC, although the Operating LLC Management Agreement provides that the salary of National Energy Group s Chief Executive Officer shall be 70% attributable to the managed oil and natural gas properties, and the salaries of each of the General Counsel and Chief Financial Officer shall be 20% attributable to the managed oil and natural gas properties. In exchange for National Energy Group s management services, Operating LLC pays National Energy Group a management fee equal to 115% of the actual direct and indirect administrative and reasonable overhead costs that National Energy Group incurs in operating the oil and natural gas properties. National Energy Group or Operating LLC may seek to change the management fee to within the range of 110%-115% as such change is deemed warranted. However, both have agreed to consult with each other to ensure that such administrative and reasonable overhead costs attributable to the managed properties are properly reflected in the management fee that is paid. In addition, Operating LLC has agreed to indemnify National Energy Group to the extent National Energy Group incurs any liabilities in connection with National Energy Group s operation of the assets and properties of Operating LLC, except to the extent of National Energy Group s gross negligence or misconduct. Operating LLC incurred $3.7 million and $5.5 million in general and administrative expenses for the nine month periods ended September 30, 2005 and 2006, respectively under this agreement.

On August 28, 2003, National Energy Group entered into a management agreement to manage the oil and natural gas business of National Onshore. The National Onshore management agreement was entered in connection with a plan of reorganization for National Onshore proposed by Thornwood Associates LP, an entity affiliated with Carl C. Icahn (the National Onshore Plan). On August 28, 2003, the United States Bankruptcy Court, Southern District of Texas, issued an order confirming the National Onshore Plan. NEG Oil & Gas owns all of the reorganized National Onshore, which is engaged in the exploration, production and transmission of oil and natural gas, primarily in South Texas, including the Eagle Bay field in Galveston Bay, Texas and the Southwest Bonus field located in Wharton County, Texas. Bob G. Alexander and Philip D. Devlin, National Energy Group s President and CEO, and National Energy Group s Vice President, Secretary and General Counsel, respectively, have been appointed to the reorganized National Onshore Board of Directors

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and act as the two principal officers of National Onshore and its subsidiaries, Galveston Bay Pipeline Corporation and Galveston Bay Processing Corporation. Randall D. Cooley, National Energy Group s Vice President and CFO, has been appointed Treasurer of reorganized National Onshore and its subsidiaries.

The National Onshore Management Agreement provides that National Energy Group shall be responsible for and have authority with respect to all of the day-to-day management of National Onshore business, but will not function as a Disbursing Agent as such term is defined in the National Onshore Plan. As consideration for National Energy Group services in managing the National Onshore business, National Energy Group receives a monthly fee of $0.3 million. The National Onshore Management Agreement is terminable (i) upon 30 days prior written notice by National Onshore, (ii) upon 90 days prior written notice by National Energy Group, (iii) upon 30 days following any day where High River designees no longer constitute the National Onshore Board of Directors, unless otherwise waived by the newly-constituted Board of Directors of National Onshore, or (iv) as otherwise determined by the Bankruptcy Court. The Company recorded $3.5 million and $3.6 million in general and administrative expenses for the nine month periods ended September 30, 2005 and 2006, respectively, under this agreement.

On November 3, 2004, the United States Bankruptcy Court for the Southern District of Texas issued an order effective November 16, 2004 confirming a plan of reorganization for National Offshore (National Offshore Plan). In connection with the National Offshore Plan, National Energy Group entered into a Management Agreement with National Offshore (the National Offshore Management Agreement) pursuant to the Bankruptcy Court s order confirming the effective date of the National Offshore Plan. NEG Oil & Gas owns all of the reorganized National Offshore. Mr. Bob G. Alexander, National Energy Group s President and CEO, has been appointed to the reorganized National Offshore Board of Directors and acts as the reorganized National Offshore s President. Mr. Philip D. Devlin, National Energy Group s Vice President, General Counsel and Secretary, has been appointed to serve in the same capacities for National Offshore. Mr. Randall D. Cooley, National Energy Group s Vice President and CFO, has been appointed as Treasurer of the reorganized National Offshore. In exchange for management services, National Energy Group receives a monthly fee equal to 115% of the actual direct and indirect administrative overhead costs that are incurred in operating and administering the National Offshore oil and natural gas properties. The Company recorded $2.9 million and $4.1 million in general and administrative expenses for the nine month periods ended September 30, 2005 and 2006, respectively, under this agreement.

Substantially concurrent with the Riata Energy purchase transaction the management agreements will be terminated.

3. Derivatives

From time to time, the Company enters into various derivative instruments consisting principally of no cost collar options (the Derivative Contracts) to reduce its exposure to price risk in the spot market for natural gas and oil. The Company follows Statement of Financial Accounting Standards No. 133 (SFAS 133), *Accounting for Derivative Instruments and Hedging Activities*, which was amended by Statement of Financial Accounting Standards No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities.* These pronouncements established accounting and reporting standards for derivative instruments and for hedging activities, which generally require recognition of all derivatives as either assets or liabilities in the balance sheet at their fair value. The accounting for changes in fair value depends on the intended use of the derivative and its resulting designation. The Company elected not to designate these instruments as hedges for accounting purposes, accordingly the cash settlements and valuation gains and losses are included in oil and

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natural gas sales. The following summarizes the cash settlements and valuation gains and losses for the nine month periods ended September 30, 2005 and 2006 (amounts in thousands):

	Nine Months Ended September 30,	
	2005	**2006**
Realized loss (net cash payments)	$ (19,486)	$ (25,014)
Unrealized gain (loss)	(111,631)	115,877
Gain (loss) on Derivative Contracts	$ (131,117)	$ 90,863

The following is a summary of the Company s Derivative Contracts as of September 30, 2006:

Type of Contract	Production Month	Volume per Month	Floor	Ceiling
No cost collars	Oct-Dec 2006	31,000 BBLS	$ 41.65	$ 45.25
No cost collars	Oct-Dec 2006	16,000 Bbls	41.75	45.40
No cost collars	Oct-Dec 2006	570,000 MMBTU	6.00	7.25
No cost collars	Oct-Dec 2006	120,000 MMBTU	6.00	7.28
No cost collars	Oct-Dec 2006	500,000 MMBTU	4.50	5.00
No cost collars	Oct-Dec 2006	46,000 Bbls	60.00	68.50
(The Company participates in a second ceiling at $84.50 on the 46,000 Bbls)				
No cost collars	Jan-Dec 2007	30,000 Bbls	57.00	70.50
No cost collars	Jan-Dec 2007	30,000 Bbls	57.50	72.00
No cost collars	Jan-Dec 2007	930,000 MMBTU	8.00	10.23
No cost collars	Jan-Dec 2007	1,000 Bbls	65.00	87.40(A)
No cost collars	Jan-Dec 2007	7,000 Bbls	65.00	86.00(A)
No cost collars	Jan-Dec 2007	330,000 MMBTU	9.60	12.10(A)
No cost collars	Jan-Dec 2007	100,000 MMBTU	9.55	12.60(A)
No cost collars	Jan-Dec 2008	46,000 Bbls	55.00	69.00
No cost collars	Jan-Dec 2008	750,000 MMBTU	7.00	10.35
No cost collars	Jan-Dec 2008	9,000 Bbls	65.00	81.25(A)
No cost collars	Jan-Dec 2008	70,000 MMBTU	8.75	11.90(A)
No cost collars	Jan-Dec 2008	270,000 MMBTU	8.80	11.45(A)
No cost collars	Jan-Dec 2009	19,000 Bbls	65.00	78.50(A)
No cost collars	Jan-Dec 2009	26,000 Bbls	65.00	77.00(A)
No cost collars	Jan-Dec 2009	330,000 MMBTU	7.90	10.80(A)

No cost collars	Jan-Dec 2009	580,000 MMBTU	7.90	11.00(A)

(A) On October 17, 2006 the Company terminated the derivative contract. See Note 12.

While the use of derivative contracts can limit the downside risk of adverse price movements, it may also limit future gains from favorable movements. The Company addresses market risk by selecting instruments whose value fluctuations correlate strongly with the underlying commodity. Credit risk related to derivative activities is managed by requiring minimum credit standards for counter parties, periodic settlements, and mark to market valuations.

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A liability of $85.9 million (including a current liability of $68.0 million) and an asset of $29.9 million (including a current asset of $14.1 million) was recorded by the Company as of December 31, 2005 and September 30, 2006, respectively, in connection with these contracts. As of December 31, 2004, the Company had issued $11.0 million in letters of credit securing the Company s derivative position. During 2005, the Company was required to provide security to counter parties for its Derivative Contracts in loss positions.

On December 22, 2005, concurrent with the execution of the company s new credit facility the Company novated all of Derivative Contracts with Shell Trading (US) outstanding as of that date with identical Derivative Contracts with Citicorp (USA), Inc. as the counter party. Under this transaction, no contracts were settled, Citicorp (USA) replaced Shell Trading (US) as the counterparty and no gain or loss was recorded. Under the new credit facility, Derivatives Contracts with certain lenders under the credit facility do not require cash collateral or letters of credit and rank pari passu with the credit facility. All cash collateral and letters of credit have been released as of December 31, 2005.

As a condition to closing the Riata purchase transaction, all derivatives contracts will be terminated or assumed by AREP. See Note 12.

4. Acquisitions

On July 10, 2006, we acquired an additional interest in our East Breaks 160 offshore block from BP America for approximately $14.1 million which increased our interest in East Breaks to approximately 66%. As a condition to closing the acquisition, we were required to issue a $16.0 million letter of credit to BP America to collaterize the potential plugging and abandonment liability associated with the offshore block. The purchase price was paid from cash on hand.

In March 2005, the Company purchased an additional interest in Longfellow Ranch for $31.9 million.

In October 2005, the Company executed a purchase and sale agreement to acquire Minden Field assets near its existing production properties in East Texas. This acquisition consists of 3,500 acres with 17 producing wells and numerous drilling opportunities. The purchase price was approximately $85.0 million, which was subsequently reduced to $82.3 million after purchase price adjustments, and the transaction closed on November 8, 2005.

5. Sale of West Delta Properties

In March 2005, the Company sold its rights and interest in West Delta 52, 54, and 58 to a third party in exchange for the assumption of existing future asset retirement obligations on the properties and a cash payment of $0.5 million. The estimated fair value of the asset retirement obligations assumed by the purchaser was approximately $16.8 million. In addition, the Company transferred to the purchaser approximately $4.7 million in an escrow account that the Company had funded relating to the asset retirement obligations on the properties. The full cost pool was reduced by approximately $11.6 million and no gain or loss was recognized on the transaction.

6. Investments/Note Receivable

In October 2003, the Company committed to an investment of $6.0 million in PetroSource Energy Company, LLC (PetroSource). The Company s commitment was to acquire 24.8% of the outstanding stock for a price of $3.0 million and to advance $3.0 million as a subordinated loan bearing 6% interest due in six years. The Company initially purchased $1.8 million in stock and funded $1.8 million of the loan in October 2003. In February 2004, the Company purchased an additional $1.2 million of stock and funded the remaining $1.2 million loan commitment. PetroSource is in the business of selling CO_2 and also owns

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pipelines and compressor stations for delivery purposes. During 2004, PetroSource sold additional equity shares which reduced the Company s ownership to 20.63%. During 2005, the Company invested an additional $0.5 million in PetroSource stock. In December 2005, the Company sold its entire investment in PetroSource, including the subordinate loan, for total proceeds of $10.5 million and recorded a gain of $5.5 million.

In April 2002, the Company entered into a revolving credit commitment to extend advances to an third party. Under the terms of the revolving credit arrangement, the Company agreed to make advances from time to time, as requested by the third party and subject to certain limitations, in an amount up to $5.0 million. Advances made under the revolving credit commitment bear interest at prime rate plus 2% and are collateralized by inventory and receivables. As of December 31, 2004, the Company determined that a portion of the total outstanding advances of $1.3 million had been impaired and recorded a loss of $0.8 million. As of December 31, 2005, the Company determined that the majority of the total outstanding advance of $1.27 million had been impaired and recorded an additional loss of $0.5 million bringing the total allowance to $1.26 million.

7. Restricted Deposits

In connection with the National Offshore transaction, the Company acquired restricted deposits aggregating $23.5 million. The restricted deposits represent bank trust and escrow accounts required to be set up by surety bond underwriters and certain former owners of National Offshore s offshore properties. In accordance with requirements of the MMS, National Offshore was required to put in place surety bonds and/or escrow agreements to provide satisfaction of its eventual responsibility to plug and abandon wells and remove structures when certain offshore fields are no longer in use. As part of National Offshore s agreement with the surety bond underwriter or the former owners of the particular fields, bank trust and escrow accounts were set up and funded based on the terms of the escrow agreements. Certain amounts are required to be paid upon receipt of proceeds from production.

The restricted deposits include the following at September 30, 2006:

1. A $4.4 million escrow account for the East Breaks 109 and 110 fields set up in favor of the surety bond underwriter who provides a surety bond to the MMS. The escrow account was fully funded as of September 30, 2006.

2. A $7.0 million escrow account for the East Breaks 165 and 209 fields set up in favor of the surety bond underwriter who provides a surety bond to the former owners of the fields and the MMS. The escrow account was fully funded as of September 30, 2006.

3. A $6.0 million escrow account set up in favor of a major oil company. The Company is required to make additional deposits to the escrow account in an amount equal to 10% of the net cash flow (as defined in the escrow agreement) from the properties that were acquired from the major oil company.

4. A $5.5 million escrow account that was required to be set up by the bankruptcy settlement proceedings of National Offshore. The Company is required to make monthly deposits based on cash flows from certain wells, as defined in the agreement.

5. $7.8 million in escrow accounts required to be set up by the MMS relating to East Breaks properties. The Company is required to make quarterly deposits to the escrow accounts of $0.8 million. Additionally, for some of the East Break properties, the Company will be required to deposit additional funds in the East Break escrow accounts, representing the difference between the required escrow deposit

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under the surety bond and actual escrow deposit balance at various points in time in the future. Aggregate payments to the East Breaks escrow accounts are as follows (in thousands):

Year Ended December 31,	
Remainder of 2006	800
2007	6,100
2008	3,200
2009	3,200
2010	5,000
Thereafter	4,000
	$ 22,300

8. Debt

The Company s debt consists of credit facilities, notes payable, note payable to affiliates and senior notes payable to affiliates.

Credit Facilities

The Operating LLC Credit Facility

On December 29, 2003, Holding LLC entered into a Credit Agreement (the Mizuho Facility) with certain commercial lending institutions, including Mizuho Corporate Bank, Ltd. as the Administrative Agent and the Bank of Texas, N.A. and the Bank of Nova Scotia as Co-Agents.

The Credit Agreement provided for a loan commitment amount of up to $145.0 million and a letter of credit commitment of up to $15 million (provided, the outstanding aggregate amount of the unpaid borrowings, plus the aggregate undrawn face amount of all outstanding letters of credit shall not exceed the borrowing base under the Credit Agreement). The Credit Agreement provided further that the amount available to the Operating LLC at any time was subject to certain restrictions, covenants, conditions and changes in the borrowing base calculation. In partial consideration of the loan commitment amount, Operating LLC has pledged a continuing security interest in all of its oil and natural gas properties and its equipment, inventory, contracts, fixtures and proceeds related to its oil and natural gas business.

At Operating LLC s option, interest on borrowings under the Credit Agreement bear interest at a rate based upon either the prime rate or the LIBOR rate plus, in each case, an applicable margin that, in the case of prime rate loans, can fluctuate from 0.75% to 2.50% per annum. Fluctuations in the applicable interest rate margins are based upon Operating LLC s total usage of the amount of credit available under the Credit Agreement, with the applicable margins increasing as Operating LLC s total usage of the amount of the credit available under the Credit Agreement increases.

At the closing of the Credit Agreement, Operating LLC borrowed $43.8 million to repay $42.9 million owed by Operating LLC to an affiliate of Mr. Icahn under the secured loan arrangement which was then terminated and to pay administrative fees in connection with this borrowing. Approximately $1.4 million of loan issuance costs was capitalized in connection with the closing of this transaction.

The Credit Agreement required, among other things, semiannual engineering reports covering oil and natural gas properties, and maintenance of certain financial ratios, including the maintenance of a minimum interest coverage, a current ratio, and a minimum tangible net worth.

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NEG Oil & Gas LLC Senior Secured Revolving Credit Facility

On December 22, 2005, NEG Oil & Gas entered into a credit agreement, dated as of December 20, 2005, with Citicorp USA, Inc., as administrative agent, Bear Stearns Corporate Lending Inc., as syndication agent, and other lender parties thereto (the NEG Credit Facility). The NEG Credit Facility is secured by substantially all the assets of NEG Oil & Gas and its subsidiaries, has a five-year term and permits payments and re-borrowings, subject to a borrowing base calculation based on the proved oil and gas reserves of the Company and its subsidiaries. Under the NEG Credit Facility, the Company will be permitted to borrow up to $500 million, and the initial borrowing base is set at $335 million. The Company used a portion of the initial $300 million funding under the NEG Credit Facility to purchase the Operating LLC Credit Facility. On a combined basis, the Operating LLC Credit Facility is no longer outstanding.

In consideration of each lender s commitment to make loans under the NEG Credit Facility, the Company is required to pay a quarterly commitment fee ranging from 0.375% to 0.50% of the available borrowing base. Commitment fees are based upon the facility utilization levels.

At the Company s option, borrowings under the NEG Credit Facility bear interest at Base Rate or Euro Dollar Rate, as defined in the borrowing agreement, plus, in each case, an applicable margin that, in the case of Base Rate loans, can fluctuate from 0.00% to 0.75% per annum, and, in the case of Euro Dollar loans, can fluctuate from 1.00% to 1.75% per annum. Fluctuations in the applicable interest rate margins are based upon the Company s total usage of the amount of credit available under the NEG Credit Facility, with the applicable margins increasing as the Company s total usage of the amount of the credit available under the NEG Credit Facility increases. Base Rate and Euro Dollar Rate fluctuate based upon Prime rate or LIBOR, respectively. At September 30, 2006 the interest rate on the outstanding amount under the credit facility was 7.38% and $14.8 million was available for future borrowings.

NEG Credit Facility agreement requires, among other things, semiannual engineering reports covering oil and natural gas properties, limitation on distributions, and maintenance of certain financial ratios, including maintenance of leverage ratio, current ratio and a minimum tangible net worth. The Company was in compliance with all covenants at September 30, 2006.

In addition to purchasing the Operating LLC Credit Facility, the Company used the proceeds from the NEG Credit Facility to (1) repay a loan of approximately $85 million by AREP used to purchase properties in the Minden Field; (2) pay a distribution of $78.0 million, and (3) pay transaction costs.

Notes Payable

Notes payable consist of the following (amounts in thousands):

	December 31, 2005	September 30, 2006

Notes payable to various prior creditors of National Onshore in settlement of bankruptcy claims. The notes are generally payable over a 30 month period with a stated interest rate of 6%; however, the notes have been discounted to an effective rate of 10%	$	2,503	$	
Less Current maturities		(2,503)		
	$		$	

NEG OIL & GAS LLC AND SUBSIDIARIES, EXCLUDING NATIONAL ENERGY GROUP, INC. AND THE 103/4% SENIOR NOTES DUE FROM NATIONAL ENERGY GROUP, INC., BUT INCLUDING NATIONAL ENERGY GROUP INC. S 50% MEMBERSHIP INTEREST IN NEG HOLDING LLC

NOTES TO COMBINED FINANCIAL STATEMENTS (Unaudited) (Continued)

Advance from Affiliate

During 2005, AREP made unsecured non-interest bearing advance of $49.8 million, payable on demand, to fund their drilling programs as well as to fund derivative contract deposits, of which $39.8 million were outstanding at December 31, 2005. The outstanding balance was repaid in January 2006.

9. Income Taxes

National Onshore and National Offshore were organized as corporations until their respective acquisitions by NEG Oil & Gas, LLC, and were subject to corporate taxes up until the date of acquisition as part of a tax sharing arrangement with the Starfire, Inc. consolidated group. The Company accounts for income taxes of National Onshore and National Offshore according to Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes (SFAS 109). SFAS 109 requires the recognition of deferred tax assets, net of applicable reserves, related to net operating loss carryforwards and certain temporary differences. The standard requires recognition of a future tax benefit to the extent that realization of such benefit is more likely than not. Otherwise, a valuation allowance is applied.

In May 2006, the State of Texas enacted legislation that replaces the taxable capital and earned surplus components of its franchise tax with a new franchise tax that is based on modified gross revenue. The new franchise tax becomes effective beginning with the 2007 tax year. The current franchise tax remains in effect through the end of 2006.

In accordance with generally accepted accounting principles in the United States, the new franchise tax is based on a measure of income, and thus accounted for in accordance with Statement of Financial Accounting Standards No. 109 Accounting for Income Taxes (SFAS 109). The provisions of SFAS 109 require recognition of the effects of the tax law change in the period of enactment. During the nine month period ended September 30, 2006, the Company recorded an income tax expense and a deferred tax liability of $2.1 million to record effects of the change in Texas franchise law.

10. Commitments and Contingencies

During the nine month period ended September 30, 2006, we entered into four drilling contracts to provide us with drilling rigs at specified drilling day rates. Due to previous commitments of the drilling rig operators, we have not taken delivery of the drilling rigs as of September 30, 2006. Our future obligations, and the estimated year of expenditure, under the drilling rig contracts are estimated as follows (dollar amounts in thousands):

		Estimated Commitment as of September 30, 2006			
Expected Drilling Location	**Contract Duration**	**Total**	**2006**	**2007**	**2008**
Onshore West Texas	Six wells (approximately 3 months)	$ 1,201	$ 1,201	$	$
Onshore East Texas	18 months	10,900	1,800	7,300	1,800

Onshore East Texas	18 months	10,900	1,200	7,300	2,400
Offshore	6 months	8,100		8,100	
Total estimated commitments		$ 31,101	$ 4,201	$ 22,700	$ 4,200

During 2000 and 2001 National Energy Group entered into several hedge contracts with Enron North America Corp (Enron NAC). In 2001, Enron Corporation and many Enron Corporation affiliates and subsidiaries, including Enron NAC filed for protection under Chapter 11 of the US bankruptcy code. The

NEG OIL & GAS LLC AND SUBSIDIARIES, EXCLUDING NATIONAL ENERGY GROUP, INC. AND THE 103/4% SENIOR NOTES DUE FROM NATIONAL ENERGY GROUP, INC., BUT INCLUDING NATIONAL ENERGY GROUP INC. S 50% MEMBERSHIP INTEREST IN NEG HOLDING LLC

NOTES TO COMBINED FINANCIAL STATEMENTS (Unaudited) (Continued)

derivative contracts were subsequently contributed to Holding LLC and then to Operating LLC. Operating LLC has filed a claim for damages in the Enron NAC bankruptcy proceeding and our designee has been appointed as a representative to the official committee of unsecured creditors. The Company s claim is unsecured. We received $0.2 million and $1.0 million for the nine month periods ended September 30, 2005 and 2006, respectively, in partial settlement of our claims, which was recorded in interest income and other. In October 2006, we received an additional $.9 million.

The Company expects to receive additional distributions from the Enron bankruptcy proceeding in accordance with its plan of reorganization. We will record such additional payments, if any, when the amounts are known.

Other than routine litigation incidental to its business operations which are not deemed by the Company to be material, there are no additional legal proceedings in which the Company, is a defendant.

Environmental Matters

The Company s operations and properties are subject to extensive federal, state, and local laws and regulations relating to the generation, storage, handling, emission, transportation, and discharge of materials into the environment. Permits are required for various of the Company s operations, and these permits are subject to revocation, modification, and renewal by issuing authorities. The Company s operations are also subject to federal, state, and local laws and regulations that impose liability for the cleanup or remediation of property which has been contaminated by the discharge or release of hazardous materials or wastes into the environment. Governmental authorities have the power to enforce compliance with their regulations, and violations are subject to fines or injunctions, or both. The Company believes that it is in material compliance with applicable environmental laws and regulations. Noncompliance with such laws and regulations could give rise to compliance costs and administrative penalties. Management does not anticipate that the Company will be required in the near future to expend amounts that are material to the financial condition or operations of the Company by reason of environmental laws and regulations, but because such laws and regulations are frequently changed and, as a result, may impose increasingly strict requirements, the Company is unable to predict the ultimate cost of complying with such laws and regulations.

11. Asset Retirement Obligation

In June 2001, the Financial Accounting Standards Board (FASB) issued Statements of Financial Accounting Standards (SFAS) No. 143, *Accounting for Asset Retirement Obligations* (SFAS 143). SFAS No. 143 requires the Company to record the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development, and/or normal use of the assets. It also requires the Company to record a corresponding asset that is depreciated over the life of the asset. Subsequent to the initial measurement of the asset retirement obligation, the obligation will be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The ARO assets are recorded on the balance sheet as part of the Company s full cost pool and are included in the amortization base for the purposes of calculating depreciation, depletion and amortization expense. For the purpose of calculating the ceiling test, the future cash outflows associated with settling the ARO liability are excluded from the computation of the discounted present value of estimated future net revenues.

NEG OIL & GAS LLC AND SUBSIDIARIES, EXCLUDING NATIONAL ENERGY GROUP, INC. AND THE 103/4% SENIOR NOTES DUE FROM NATIONAL ENERGY GROUP, INC., BUT INCLUDING NATIONAL ENERGY GROUP INC. S 50% MEMBERSHIP INTEREST IN NEG HOLDING LLC

NOTES TO COMBINED FINANCIAL STATEMENTS (Unaudited) (Continued)

The following is a rollforward of the asset retirement obligation as of December 31, 2005 and September 30, 2006 (amounts in thousands).

Balance as of December 31, 2005	$ 41,228
Add: Accretion	2,112
Drilling additions	
Acquired properties	4,269
Less: Revisions	
Settlements	
Dispositions	
Balance as of September 30, 2006	$ 47,609

12. Subsequent Events

As a condition to closing the Riata Energy purchase transaction, the Company is required to terminate or otherwise assign all derivatives contracts to AREP. On October 17, 2006, the Company terminated all of its derivatives contracts for 2009 production and some of it derivatives contracts relating to 2007 and 2008 production. The Company received $17.6 million in cash upon termination of the contracts. No gain or loss was recognized upon termination because the derivatives contracts are recorded at fair market value.

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ANNEX A

GLOSSARY OF NATURAL GAS AND OIL TERMS

The following is a description of the meanings of some of the natural gas and oil industry terms used in this prospectus.

2-D seismic or 3-D seismic. Geophysical data that depict the subsurface strata in two dimensions or three dimensions, respectively. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D seismic.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in this prospectus in reference to crude oil or other liquid hydrocarbons.

Bcf. Billion cubic feet of natural gas.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

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

Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

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.

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

CO_2. Carbon Dioxide.

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

Development well. A well drilled into a proved 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.

Environmental Assessment (EA). A study to determine whether a federal action significantly affect the environment, which federal agencies may be required by the National Environmental Policy Act or similar state statutes to undertake prior to the commencement of activities that would constitute federal actions, such as natural gas and oil exploration and production activities on federal lands.

Environmental Impact Statement. A more detailed study of the environmental effects of a federal undertaking and its alternatives than an EA, which may be required by the National Environmental Policy Act or similar state statutes, either after the EA has been prepared and determined that the environmental consequences of a proposed federal undertaking, such as natural gas and oil exploration and production activities on federal lands, may be significant, or without the initial preparation of an EA if a federal agency anticipates that a proposed federal undertaking may significantly impact the environment.

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 either a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

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Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

High CO_2 gas. Natural gas that contains more than 10% CO_2 by volume.

Imbricate stacking. A geological formation characterized by multiple layers lying lapped over each other.

MBbls. Thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. Thousand cubic feet of natural gas.

Mcf/d. Mcf per day.

Mcfe. Thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MmBbls. Million barrels of crude oil or other liquid hydrocarbons.

Mmboe. Million barrels of oil equivalent.

MBtu. Thousand British Thermal Units.

MmBtu. Million British Thermal Units.

Mmcf. Million cubic feet of natural gas.

Mmcf/d. Mmcf per day.

Mmcfe. Million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Mmcfe/d. Mmcfe per day.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells, as the case may be.

Plugging and abandonment. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.

Present value of future net revenues (PV-10). The present value of estimated future revenues to be generated from the production of proved reserves, before income taxes, calculated in accordance with SEC guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation and without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization. PV-10 is calculated using an annual discount rate of 10%.

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.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed reserves. Has the meaning given to such term in Rule 4-10(a)(3) of Regulation S-X, which defines proved developed reserves as:

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved reserves. Has the meaning given to such term in Rule 4-10(a)(2) of Regulation S-X, which defines proved reserves as:

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following: (A) Oil that may become available from known reservoirs but is classified separately as indicated additional reserves; (B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved undeveloped reserves. Has the meaning given to such term in Rule 4-10(a)(4) of Regulation S-X, which defines proved undeveloped reserves as:

Proved undeveloped oil and gas reserves are 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. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Pulling Units. Pulling units are used in connection with completions and workover operations.

PV-10. See Present value of future net revenues.

Rental Tools. A variety of rental tools and equipment, ranging from trash trailers to blow out preventors to sand separators, for use in the oil field.

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.

Roustabout Services. The provision of manpower to assist in conducting oil field operations.

Standardized Measure or Standardized Measure of Discounted Future Net Cash Flows. The present value of estimated future cash inflows from proved natural gas and oil reserves, less future development and production costs and future income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized Measure differs from PV-10 because Standardized Measure includes the effect of future income taxes and asset retirement obligations on future net revenues.

Stratigraphic play. An oil or natural gas formation contained within an area created by permeability and porosity changes characteristic of the alternating rock layer that result from the sedimentation process.

Trucking. The provision of trucks to move our drilling rigs from one well location to another and to deliver water and equipment to the field.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether such acreage contains proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.

Part II

INFORMATION NOT REQUIRED IN PROSPECTUS

Item 13. *Other Expenses of Issuance and Distribution*

Set forth below are the expenses (other than underwriting discounts and commissions) expected to be incurred in connection with the issuance and distribution of the securities registered hereby. With the exception of the Securities and Exchange Commission registration fee, the amounts set forth below are estimates:

Securities and Exchange Commission registration fee	$ 9,656
Legal fees and expenses	25,000
Accounting fees and expenses	
Miscellaneous	5,000
TOTAL	$ 39,656

Item 14. *Indemnification of Directors and Officers*

Section 145 of the Delaware General Corporation Law (DGCL) provides that a corporation may indemnify any person who was or is a party or is threatened to be made a party to any threatened, pending or completed action, suit or proceeding whether civil, criminal, administrative or investigative (other than an action by or in the right of the corporation) by reason of the fact that he is or was a director, officer, employee or agent of the corporation, or is or was serving at the request of the corporation as a director, officer, employee or agent of another corporation, partnership, joint venture, trust or other enterprise, against expenses (including attorneys fees), judgments, fines and amounts paid in settlement actually and reasonably incurred by him in connection with such action, suit or proceeding if he acted in good faith and in a manner he reasonably believed to be in or not opposed to the best interests of the corporation, and, with respect to any criminal action or proceeding, had no reasonable cause to believe his conduct was unlawful. Section 145 further provides that a corporation similarly may indemnify any such person serving in any such capacity who was or is a party or is threatened to be made a party to any threatened, pending or completed action or suit by or in the right of the corporation to procure a judgment in its favor by reason of the fact that he is or was a director, officer, employee or agent of the corporation or is or was serving at the request of the corporation as a director, officer, employee or agent of another corporation, partnership, joint venture, trust or other enterprise, against expenses (including attorneys fees) actually and reasonably incurred in connection with the defense or settlement of such action or suit if he acted in good faith and in a manner he reasonably believed to be in or not opposed to the best interests of the corporation and except that no indemnification shall be made in respect of any claim, issue or matter as to which such person shall have been adjudged to be liable to the corporation unless and only to the extent that the Delaware Court of Chancery or such other court in which such action or suit was brought shall determine upon application that, despite the adjudication of liability but in view of all of the circumstances of the case, such person is fairly and reasonably entitled to indemnity for such expenses which the Delaware Court of Chancery or such other court shall deem proper. The Company s certificate of incorporation and bylaws provide that indemnification shall be to the fullest extent permitted by the DGCL for all current or former directors or officers of the Company. As permitted by the DGCL, the certificate of incorporation provides that directors of the Company shall have no personal liability to the Company or its stockholders for monetary damages for breach of fiduciary duty as a director, except (1) for any breach of the director s duty of loyalty to the Company or its stockholders, (2) for acts or omissions not in good faith or which involve intentional misconduct or knowing violation of law, (3) under Section 174 of the DGCL or (4) for any transaction from which a director derived an improper personal benefit.

Item 15. *Recent Sales of Unregistered Securities*

During the past three years, we have issued unregistered securities to a limited number of persons, as described below:

On December 21, 2005, we acquired ownership interests in a variety of entities in which we previously held interests, as well as additional leasehold and working interests in natural gas and oil properties in the Piceance Basin, in exchange for consideration of $68.5 million, including 3,508,335 shares of our common stock and $15.9 million in additional cash. This transaction did not involve any underwriter or a public offering, and we believe this transaction was exempt from registration requirements pursuant to Section 4(2) of the Securities Act and Regulation D promulgated thereunder. Each of the recipients of these securities represented their status as an accredited investor as defined in Rule 501(a) under the Securities Act.

We sold 12,500,000 shares of our common stock on December 21, 2005 and an additional 239,630 shares of our common stock on January 9, 2006 in a private placement to Banc of America Securities LLC and Goldman, Sachs & Co. who resold those shares to certain eligible investors. In connection with this private placement, we received net proceeds of $175.7 million after deducting the initial purchasers discount of $13.4 million and expenses of $2.0 million. This transaction did not involve a public offering, and we believe this transaction was exempt from registration requirements pursuant to Section 4(2) of the Securities Act. We believe the resale of the securities by the initial purchasers was exempt from registration requirements pursuant to Rule 144A promulgated under the Securities Act and the analysis commonly known as Rule 4(11/2).

On December 21, 2005, we granted restricted stock awards consisting of an aggregate of 1,552,167 shares of our common stock. This transaction did not involve any underwriter or a public offering, and we believe this transaction was exempt from registration requirements pursuant to Securities and Exchange Commission Rule 701 under the Securities Act.

On December 22, 2005, we acquired certain interests in several natural gas and oil properties in West Texas from Carl E. Gungoll Exploration, LLC and certain other parties in exchange for consideration of approximately $6.0 million, including 174,833 shares of our common stock and $5.4 million in additional cash. This transaction did not involve any underwriter or a public offering, and we believe this transaction was exempt from registration requirements pursuant to Section 4(2) of the Securities Act of 1933, as amended (the Securities Act), and Regulation D promulgated thereunder. Each of the recipients of these securities represented their status as an accredited investor as defined in Rule 501(a) under the Securities Act.

On May 26, 2006, we acquired working interests in leases in West Texas in exchange for consideration of approximately $12.9 million, including 251,351 shares of our common stock and $8.2 million in additional cash. This transaction did not involve any underwriter or a public offering, and we believe this transaction was exempt from registration requirements pursuant to Section 4(2) of the Securities Act and Regulation D promulgated thereunder. Each of the recipients of these securities represented their status as an accredited investor as defined in Rule 501(a) under the Securities Act.

On June 7, 2006, we acquired the remaining 1% equity interest in PetroSource in exchange for approximately $0.1 million consisting of 27,749 shares of our common stock. This transaction did not involve any underwriter or a public offering, and we believe this transaction was exempt from registration requirements pursuant to Section 4(2) of the Securities Act and Regulation D promulgated thereunder. Each of the recipients of these securities represented their status as an accredited investor as defined in Rule 501(a) under the Securities Act.

On November 21, 2006, we acquired all of the outstanding equity interests of NEG in exchange for consideration of approximately $1,500.5 million, including $990.4 million in cash, the assumption of $300 million in debt, the receipt of $21.1 million in cash and 12,842,000 shares of our common stock. This transaction did not involve any underwriter or a public offering, and we believe this transaction was exempt from registration requirements pursuant to Section 4(2) of the Securities Act and Regulation D promulgated thereunder. Each of the recipients of these securities represented their status as an accredited investor as defined in Rule 501(a) under the Securities Act.

On November 21, 2006, we issued 2,136,668 shares of our convertible preferred stock and common units consisting of and aggregate of 5,331,580 shares of our common stock and warrants entitling the holder to shares of our convertible preferred stock upon surrender of an equal amount of the shares of common stock issued as part of a common unit. In connection with this private placement, we received net proceeds of approximately $536.9 million after deducting expenses of approximately $13.2 million. Banc of America Securities LLC acted as placement agent in connection with this transaction. This offering was only made to (a) two large institutional accredited investors as such term is defined in Rule 501(a)(1), (2), (3) or (7) under the Securities Act and (b) investors that are both (i) accredited investors as defined in Rule 501(a) under the Securities Act and (ii) qualified institutional buyers within the meaning of Rule 144A under the Securities Act. This transaction did not involve any underwriter or a public offering, and we believe this transaction was exempt from registration requirements pursuant to Section 4(2) of the Securities Act and Regulation D promulgated thereunder.

On March 20, 2007, we issued 13,888,888 shares of common stock to two institutional accredited investors as defined in Rule 501(a)(1), (2), (3) or (7) under the Securities Act, including an affiliate of Mr. Ward, our Chairman, President and Chief Executive Officer, and an additional 3,891,767 shares of common stock to certain holders of our convertible preferred stock pursuant to a preemptive right. In connection with this private placement, we received net proceeds of approximately $318.9 million after deducting expenses of approximately by $1.1 million. This transaction did not involve any underwriter or a public offering, and we believe this transaction was exempt from registration requirements pursuant to Section 4(2) of the Securities Act and Regulation D promulgated thereunder.

Item 16. ***Exhibits and Financial Statement Schedules***

a. *Exhibits:*

3.1	Certificate of Incorporation
3.2	Certificate of Designation of convertible preferred stock
3.3	Bylaws
4.1	Specimen Stock Certificate representing common stock
4.2	Resale Registration Rights Agreement, dated December 21, 2005, by and between SandRidge Energy, Inc. (as successor by merger to Riata Energy, Inc.) and Banc of America Securities, LLC
4.3	Registration Rights Agreement, dated November 21, 2006, by and among SandRidge Energy, Inc. (as successor by merger to Riata Energy, Inc.) and the Purchasers party thereto
4.4	Securities Purchase Agreement, dated November 21, 2006, by and among SandRidge Energy, Inc. (as successor by merger to Riata Energy, Inc.) and the Purchasers party thereto
4.5	Specimen Stock Certificate representing convertible preferred stock
4.6	Form of Warrant
4.7	Amended and Restated Shareholders Agreement, dated April 4, 2007, among SandRidge Energy, Inc. (as successor by merger to Riata Energy, Inc.) and certain shareholders
4.8	Registration Rights Agreement, dated March 20, 2007, by and among SandRidge Energy, Inc. and the several purchasers party thereto
4.9	Stock Purchase Agreement, dated February 12, 2007, by and among SandRidge Energy, Inc. and each of the investors signatory thereto
4.10	Shareholders Agreement, dated March 20, 2007, by and among SandRidge Energy, Inc. and certain common shareholders
4.11	Form of Consent to Amend the December 2005 Resale Registration Rights Agreement, dated June 13, 2006
4.12	Form of Consent to Amend the December 2005 Resale Registration Rights Agreement, dated April 23, 2007
4.13	Form of Consent to Amend the December 2005 Resale Registration Rights Agreement, dated October 4, 2007

4.14	Form of Consent to Amend the November 2006 Registration Rights Agreement, dated October 4, 2007
4.15	Form of Consent to Amend the March 2007 Registration Rights Agreement, dated October 4, 2007
5.1	Opinion of Vinson & Elkins L.L.P.
10.1	401(k) Plan of SandRidge Energy, Inc.
10.2	2005 Stock Plan of SandRidge Energy, Inc.

10.3	Employment Participation Plan of SandRidge Energy, Inc.
10.4	Well Participation Plan of SandRidge Energy, Inc.
10.5	Form of Indemnification Agreement
10.6	Senior Credit Facility, dated November 21, 2006, by and among SandRidge Energy, Inc. (as successor by merger to Riata Energy, Inc.) and Bank of America, N.A., as Administrative Agent and Banc of America Securities LLC as Lead Arranger and Book Running Manager
10.7	Senior Bridge Facility, dated November 21, 2006, by and among SandRidge Energy, Inc. (as successor by merger to Riata Energy, Inc.) and Banc of America Bridge LLC, as the Initial Bridge Lender and Banc of America Securities LLC, Credit Suisse Security, Goldman, Sachs Credit Partners L.P., and Lehman Brothers, Inc. as joint lead arrangers and book runners
10.8	Credit Agreement, dated March 22, 2007 by and among SandRidge Energy, Inc. and Bank of America, N.A., as Administrative Agent and Banc of America Securities LLC as Lead Arranger
10.9	Amendment No. 1 to Senior Credit Facility, dated November 21, 2006, by and among SandRidge Energy, Inc. (as successor by merger to Riata Energy, Inc.) and Bank of America, N.A., as Administrative Agent and Banc of America Securities LLC as Lead Arranger and Book Running Manager
10.10	Amendment No. 2 to Senior Credit Facility, dated November 21, 2006, by and among SandRidge Energy, Inc. (as successor by merger to Riata Energy, Inc.) and Bank of America, N.A., as Administrative Agent and Banc of America Securities LLC as Lead Arranger and Book Running Manager
10.11	Employment Agreement of Tom L. Ward
10.12	Employment Agreement of Larry K. Coshow
10.13	Partnership Interest Purchase Agreement, dated November 21, 2005 by and among Riata Energy, Inc. and Matthew McCann
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23.2	Consent of DeGolyer & MacNaughton
23.3	Consent of Vinson & Elkins L.L.P. (Contained in Exhibit 5.1)
23.4	Consent of Grant Thornton LLP
23.5	Consent of Netherland, Sewell & Associates, Inc.

23.6	Consent of Harper & Associates, Inc.
24.1	Power of Attorney (included on signature page)

b. *Financial Statement Schedules*

None.

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Item 17. *Undertakings*

(a) The undersigned registrant hereby undertakes:

(1) To file, during any period in which offers or sales are being made, a post-effective amendment to this registration statement:

(i) To include any prospectus required by Section 10(a)(3) of the Securities Act of 1933;

(ii) To reflect in the prospectus any facts or events arising after the effective date of the registration statement (or the most recent post-effective amendment thereof) which, individually or in the aggregate, represent a fundamental change in the information set forth in the registration statement. Notwithstanding the foregoing, any increase or decrease in volume of securities offered (if the total dollar value of securities offered would not exceed that which was registered) and any deviation from the low or high end of the estimated maximum offering range may be reflected in the form of prospectus filed with the Securities and Exchange Commission pursuant to Rule 424(b) if, in the aggregate, the changes in volume and price represent no more than a 20 percent change in the maximum aggregate offering price set forth in the Calculation of Registration Fee table in the effective registration statement; and

(iii) To include any material information with respect to the plan of distribution not previously disclosed in the registration statement or any material change to such information in the registration statement.

(2) That, for the purpose of determining any liability under the Securities Act of 1933, each such post-effective amendment shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

(3) To remove from registration by means of a post-effective amendment any of the securities being registered which remain unsold at the termination of the offering.

(4) That, for the purpose of determining liability under the Securities Act of 1933 to any purchaser, each prospectus filed pursuant to Rule 424(b) as part of a registration statement relating to an offering, other than registration statements relying on Rule 430B or other than prospectuses filed in reliance on Rule 430A, shall be deemed to be part of and included in the registration statement as of the date it is first used after effectiveness. Provided, however, that no statement made in a registration statement or prospectus that is part of the registration statement or made in a document incorporated or deemed incorporated by reference into the registration statement or prospectus that is part of the registration statement will, as to a purchaser with a time of contract of sale prior to such first use, supersede or modify any statement that was made in the registration statement or prospectus that was part of the registration statement or made in any such document immediately prior to such date of first use.

(5) That, for the purpose of determining liability of the registrant under the Securities Act of 1933 to any purchaser in the initial distribution of the securities: The undersigned registrant undertakes that in a primary offering of securities of the undersigned registrant pursuant to this registration statement, regardless of the underwriting method used to sell the securities to the purchaser, if the securities are offered or sold to such purchaser by means of any of the following communications, the undersigned registrant will be a seller to the purchaser and will be considered to offer or sell such securities to such purchaser:

(i) Any preliminary prospectus or prospectus of the undersigned registrant relating to the offering required to be filed pursuant to Rule 424;

(ii) Any free writing prospectus relating to the offering prepared by or on behalf of the undersigned registrant or used or referred to by the undersigned registrant;

(iii) The portion of any other free writing prospectus relating to the offering containing material information about the undersigned registrant or its securities provided by or on behalf of the undersigned registrant; and

(iv) Any other communication that is an offer in the offering made by the undersigned registrant to the purchaser.

(b) Insofar as indemnification for liabilities arising under the Securities Act of 1933 may be permitted to directors, officers and controlling persons of the registrant pursuant to the foregoing provisions, 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 of 1933 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, 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 of 1933 and will be governed by the final adjudication of such issue.

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SIGNATURES

Pursuant to the requirements of the Securities Act of 1933, as amended, the Registrant has duly caused this Registration Statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Oklahoma, in the State of Oklahoma on January 30, 2008.

SANDRIDGE ENERGY, INC.

By: /s/ Tom L. Ward

Name: Tom L. Ward

Title: President, Chief Executive Officer

And Chairman of the Board

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Tom L. Ward and V. Bruce Thompson, and each of them severally, his true and lawful attorney or attorneys-in-fact and agents, with full power to act with or without the others and with full power of substitution and resubstitution, to execute in his name, place and stead, in any and all capacities, any or all amendments (including pre-effective and post-effective amendments) to this Registration Statement and any registration statement for the same offering filed pursuant to Rule 462 under the Securities Act of 1933, as amended, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents and each of them, full power and authority to do and perform in the name of on behalf of the undersigned, in any and all capacities, each and every act and thing necessary or desirable to be done in and about the premises, to all intents and purposes and as fully as they might or could do in person, hereby ratifying, approving and confirming all that said attorneys-in-fact and agents or their substitutes may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Act of 1933, as amended, this Registration Statement has been signed below by the following persons in the capacities and on the dates indicated below.

Signature	Title	Date
/s/ Tom L. Ward Tom L. Ward	President, Chief Executive Officer And Chairman of the Board (Principal Executive Officer)	January 30, 2008
/s/ Dirk M. Van Doren Dirk M. Van Doren	Chief Financial Officer and Executive Vice President (Principal Financial Officer)	January 30, 2008
/s/ Randall D. Cooley Randall D. Cooley	Senior Vice President of Accounting (Principal Accounting Officer)	January 30, 2008
/s/ Dan Jordan Dan Jordan	Director	January 30, 2008
/s/ Bill Gilliland	Director	January 30, 2008

Bill Gilliland		
/s/ Roy T. Oliver, Jr.	Director	January 30, 2008
Roy T. Oliver, Jr.		

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Signature	Title	Date
/s/ Stuart W. Ray	Director	January 30, 2008
Stuart W. Ray		
/s/ D. Dwight Scott	Director	January 30, 2008
D. Dwight Scott		
/s/ Jeff Serota	Director	January 30, 2008
Jeff Serota		

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EXHIBIT INDEX

3.1	Certificate of Incorporation
3.2	Certificate of Designation of convertible preferred stock
3.3	Bylaws
4.1	Specimen Stock Certificate representing common stock
4.2	Resale Registration Rights Agreement, dated December 21, 2005, by and between SandRidge Energy, Inc. (as successor by merger to Riata Energy, Inc.) and Banc of America Securities, LLC
4.3	Registration Rights Agreement, dated November 21, 2006, by and among SandRidge Energy, Inc. (as successor by merger to Riata Energy, Inc.) and the Purchasers party thereto
4.4	Securities Purchase Agreement, dated November 21, 2006, by and among SandRidge Energy, Inc. (as successor by merger to Riata Energy, Inc.) and the Purchasers party thereto
4.5	Specimen Stock Certificate representing convertible preferred stock
4.6	Form of Warrant
4.7	Amended and Restated Shareholders Agreement, dated April 4, 2007, among SandRidge Energy, Inc. (as successor by merger to Riata Energy, Inc.) and certain shareholders
4.8	Registration Rights Agreement, dated March 20, 2007, by and among SandRidge Energy, Inc. and the several purchasers party thereto
4.9	Stock Purchase Agreement, dated February 12, 2007, by and among SandRidge Energy, Inc. and each of the investors signatory thereto
4.10	Shareholders Agreement, dated March 20, 2007, by and among SandRidge Energy, Inc. and certain common shareholders
4.11	Form of Consent to Amend the December 2005 Resale Registration Rights Agreement, dated June 13, 2006
4.12	Form of Consent to Amend the December 2005 Resale Registration Rights Agreement, dated April 23, 2007
4.13	Form of Consent to Amend the December 2005 Resale Registration Rights Agreement, dated October 4, 2007
4.14	Form of Consent to Amend the November 2006 Registration Rights Agreement, dated October 4, 2007
4.15	Form of Consent to Amend the March 2007 Registration Rights Agreement, dated October 4, 2007

5.1	Opinion of Vinson & Elkins L.L.P.
10.1	401(k) Plan of SandRidge Energy, Inc.
10.2	2005 Stock Plan of SandRidge Energy, Inc.
10.3	Employment Participation Plan of SandRidge Energy, Inc.
10.4	Well Participation Plan of SandRidge Energy, Inc.
10.5	Form of Indemnification Agreement
10.6	Senior Credit Facility, dated November 21, 2006, by and among SandRidge Energy, Inc. (as successor by merger to Riata Energy, Inc.) and Bank of America, N.A., as Administrative Agent and Banc of America Securities LLC as Lead Arranger and Book Running Manager
10.7	Senior Bridge Facility, dated November 21, 2006, by and among SandRidge Energy, Inc. (as successor by merger to Riata Energy, Inc.) and Banc of America Bridge LLC, as the Initial Bridge Lender and Banc of America Securities LLC, Credit Suisse Security, Goldman, Sachs Credit Partners L.P., and Lehman Brothers, Inc. as joint lead arrangers and book runners
10.8	Credit Agreement, dated March 22, 2007 by and among SandRidge Energy, Inc. and Bank of America, N.A., as Administrative Agent and Banc of America Securities LLC as Lead Arranger
10.9	Amendment No. 1 to Senior Credit Facility, dated November 21, 2006, by and among SandRidge Energy, Inc. (as successor by merger to Riata Energy, Inc.) and Bank of America, N.A., as Administrative Agent and Banc of America Securities LLC as Lead Arranger and Book Running Manager

10.10	Amendment No. 2 to Senior Credit Facility, dated November 21, 2006, by and among SandRidge Energy, Inc. (as successor by merger to Riata Energy, Inc.) and Bank of America, N.A., as Administrative Agent and Banc of America Securities LLC as Lead Arranger and Book Running Manager
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