SANDRIDGE ENERGY INC
Form S-1/A
December 05, 2007

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As filed with the Securities and Exchange Commission on December 4, 2007
Registration No. 333-145386

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Amendment No. 1
to
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

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 DECEMBER 4, 2007

Prospectus

57,601,952 Shares

SandRidge Energy, Inc.

Common Stock

This prospectus relates to up to 57,601,952 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 , 2007

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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 June 30, 2007, we had interests in approximately 959,958 gross (651,308 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, five 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

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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 2007 of approximately $1,200 million include $943 million allocated to exploration and development (including land and seismic acquisitions and our tertiary recovery operations), $115 million allocated to drilling and oil field services and $103 million allocated to midstream operations. Approximately $704 million of our 2007 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 296 gross (256 net) wells in 2007, including approximately 207 gross (177 net) wells in the WTO. The actual number of wells drilled and the amount of our 2007 capital expenditures will be dependent upon market conditions, availability of capital and drilling and production results. We have made capital expenditures of $492.1 million in the first six months of 2007.

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

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approximately 19 years. Our core area of operations in the WTO has expanded to 499,607 gross (404,397 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 own % of our capital stock on a fully-diluted basis as of , 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 June 30, 2007 unless otherwise noted:

Area	Estimated Net Proved Reserves (Bcfe)	PV-10 (in millions)(1)	Daily Production (Mmcfe/d)(2)	Proved Reserves/ Production	Gross Acreage	Net Acreage	Number of Identified Potential Drilling Locations
WTO	648.3	$ 1,190.9	68.2	26.0(3)	499,607	404,397	2,658
East Texas	156.3	310.2	26.8	16.0	48,606	32,557	566

Gulf Coast	104.5	410.7	35.0	8.3	53,464	34,765	51
Other(4)	265.9	646.9	38.9	18.6	358,281	179,589	1,298(4)
Total	1,174.0	$ 2,558.8	168.9	19.0	959,958	651,308(6)	4,573

(1) 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.

(2) Represents average daily net production for the month of June 2007. Average daily net production for the month of September 2007 was 191.2 Mmcfe per day.

(3) 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.

(4) 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.

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

(6) Our total net acreage as of September 30, 2007 was 763,031 acres.

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 250 Bcfe from less than 350 wells through June 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 will cover 360 square miles and should both be completed by the end of 2007.

We have aggressively acquired leasehold acreage in the WTO, nearly tripling our position since January 2006. As of June 30, 2007, we owned 499,607 gross (404,397 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 200 Bcfe through June 30, 2007 and currently produces in excess of 110 gross Mmcfe per day.

Our interests in the Piñon Field included 331 producing wells as of June 30, 2007. We had an 84.3% average working interest in the producing area of Piñon Field and were running 30 drilling rigs in the Piñon Field as of June 30, 2007. We estimate that we will drill approximately 205 wells in the field during 2007, the majority of which will be development wells. 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, on which we will drill exploratory wells in late 2007 or early 2008:

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 and may drill additional wells in late 2007 following the integration of this data and new subsurface well control.

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. We plan to conduct a 3-D seismic survey over the Big Canyon prospect area as part of Phase II of our 3-D seismic program in 2007. Exploratory wells may be planned in late 2007 and early 2008 to further evaluate both the Tesnus and the Caballos in a location structurally updip to the Big Canyon Ranch 106-1 well.

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 plan to have five rigs running in this region during the remainder of 2007. As of June 30, 2007, East Texas accounted for 156.3 Bcfe of proved reserves, 566 potential drilling locations of which 49 are anticipated to be drilled in 2007, and approximately $110 million of budgeted 2007 capital expenditures.

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, 51 potential drilling locations and approximately $28 million of budgeted 2007 capital expenditures.

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 five 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,

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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 92.5% 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 85 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 275 miles of West Texas natural gas gathering pipelines. At June 30, 2007 we operated or owned approximately 27,000 horsepower of gas compression.

In order to ensure sufficient capacity for our existing and future Piñon Field production, we plan to install an additional 26,000 horsepower of compression and approximately 40 miles of large diameter pipeline by the end of 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 161 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

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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.

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The Offering

Common stock offered by the selling stockholders(1)	57,601,952 shares
Common stock outstanding(2)	141,845,601 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

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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	1.33
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 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 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 June 30, 2007, we participated in drilling a total of 109 gross wells, of which three 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

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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

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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.

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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 or property 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 control deficiency or a combination of control deficiencies, that results in a more than remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected.

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 141,845,601 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 57,601,952 shares the selling stockholders are selling in this offering will be freely

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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 June 30, 2007, we were authorized to issue 400,000,000 shares of common stock and 50,000,000 shares of preferred stock with preferences and rights as determined by our Board of Directors. As of , 2007, we had shares of common stock outstanding and pursuant to our stock incentive plan, we have also reserved 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 capital raising purposes or for

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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.

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 Shareholders.

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.

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 has taken steps to improve and continues 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 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.

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, 26 of our rigs are working on properties that we operate; ten of our rigs are drilling on a contract basis for third-parties; five are being retrofitted and three 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 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	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.

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.

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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.

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.

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	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.

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, 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 we are unable to or do not offer to exchange the term loan for senior unsecured notes with registration rights by April 30, 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.

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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						
	Remainder of 2007	2008	2009	2010	2011	After 2011	Total
	(In thousands)						
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 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.

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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. We currently do not enter into derivative arrangements with respect to our oil production, but we may do so in the future if our oil production increases as a result of the initiation of our CO_2 tertiary oil recovery operations. 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 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 September 30, 2007, our open commodity derivative contracts consisted of the following:

Period	Commodity	Notional		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)

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.

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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 June 30, 2007, we had interests in approximately 959,958 gross (651,308 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, five 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 2007 of approximately $1,200 million include $943 million allocated to exploration and development (including land and seismic acquisitions and our tertiary recovery operations), $115 million allocated to drilling and oil field services and $103 million allocated to midstream gas operations. Approximately $704 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 296 gross (256 net) wells in 2007, including approximately 207 gross (177 net) wells in the WTO. The actual number of wells drilled in our drilling program and the amount of our 2007 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 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 plan to have five rigs running in this region through 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 499,607 gross (404,397 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 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 own % of our capital stock on a fully-diluted basis as of , 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, five 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 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 June 30, 2007 unless otherwise noted:

	Estimated Net Proved Reserves (Bcfe)	PV-10 (in millions)(1)	Daily Production (Mmcfe/d)	Proved Reserves/ Production	Gross Acreage	Net Acreage	Number of Identified Potential Drilling Locations
Area							
WTO	648.3	$ 1,190.9	68.2	26.0(2)	499,607	404,397	2,658
East Texas	156.3	310.2	26.8	16.0	48,606	32,557	566
Gulf Coast	105.7	416.4	35.0	8.3	53,464	34,765	51
Other:							
Gulf of Mexico	57.3	176.7	20.5	7.7	73,614	36,770	82
Other West Texas	27.0	111.2	8.3	9.0	23,059	22,140	68
PetroSource	120.8	243.8	1.3	263.1	9,064	8,195	47
Piceance Basin	10.5	11.8	1.3	21.6	40,334	15,686	828
Other	48.1	110.5	7.5	17.3	212,210	96,798	273
Total	1,174.0	$ 2,558.8	168.9	19.2	959,958	651,308(4)	4,573

(1) 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.

(2) Represents average daily net production for the month of June 2007. Average daily net production for the month of September 2007 was 191.2.

(3) 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.

(4) Our total net acreage as of September 30, 2007 was 763,031 acres.

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 250 Bcfe from less than 350 wells through June 30, 2007. We believe our access to and control of the necessary infrastructure

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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 will cover 360 square miles and should both be completed by the end of 2007.

We have aggressively acquired leasehold acreage in the WTO, nearly tripling our position since January 2006. As of June 30, 2007 we owned 499,607 gross (404,397 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. 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 250 Bcfe through June 30, 2007 and currently produces in excess of 110 gross Mmcfe per day.

Our interests in the Piñon Field include 331 producing wells as of June 30, 2007. We had an 84.3% average working interest in the producing area of Piñon Field and were running 30 drilling rigs in the Piñon Field as of June 30, 2007. We estimate that we will drill approximately 207 wells in the field during 2007, the majority of which will be development wells. 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 on which we will drill exploratory wells in late 2007 or early 2008:

> *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 and may drill additional wells in late 2007 following the integration of this data and new subsurface well control.
>
> *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. We plan to conduct a 3-D seismic survey over the Big Canyon prospect area as part of Phase II of our 3-D seismic program in 2007. Exploratory wells may be planned in late 2007 and early 2008 to further evaluate both the Tesnus and the Caballos in a location structurally updip to the Big Canyon Ranch 106-1 well.

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West Texas Overthrust Development. The following table provides information concerning 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 2Q 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 June 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. Twenty-two wells have been drilled in the first half of 2007. We plan to have five rigs running in this region for the remainder of 2007 with an additional 27 wells planned.

Gulf Coast

We own natural gas and oil interests in 53,464 gross (34,765 net) acres in the Gulf Coast area as of June 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. Three wells have been drilled in the first six months of 2007. We are evaluating additional drilling opportunities for the remainder of 2007.

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. 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.

We are currently evaluating wells we have drilled, but not completed, on the western portion of our acreage block. At June 30, 2007, we had identified 828 potential drilling locations on the eastern portion of our 40,334 gross (15,686 net) acres. We will continue to evaluate our position in 2007 and intend to manage our investment in this area to maximize returns without significantly increasing future capital expenditures.

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 June 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, and intend to drill approximately 17 development wells in 2007.

Other. We own interests in properties in the Arkoma and Anadarko Basins and other non-strategic areas. As of June 30, 2007, we hold interests in 212,210 gross (96,798 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 our injection rate is expected to reach 32.0 Mmcf per day in 2007 and 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. We are currently moving ahead with the implementation of a nine pattern pilot program which is expected to begin CO_2 injection in the third quarter of 2007. As of June 30, 2007, net proved reserves attributable to the George

Allen Unit were 8.2 Mmboe. The CO_2 injection rate is expected to reach 15 Mmcf per day by end of year 2007.

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.

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	1.33
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 June 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	331	270
East Texas	144	134
Gulf Coast	219	135
Other:		
Gulf of Mexico	58	42
Other West Texas	303	292
PetroSource	38	34
Piceance Basin	44	15
Other	332	118
Total	1,469	1,040

Developed and Undeveloped Acreage

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

	Developed Acreage(1)		Undeveloped Acreage(2)	
Area	**Gross(3)**	**Net(4)**	**Gross(3)**	**Net(4)**
WTO	13,702	11,106	485,905	393,291
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	81,698	39,801	130,512	56,996
Total	262,080	160,362	697,878	490,946

(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.

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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 June 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	3,953	2,507
December 31, 2008	48,443	40,593
December 31, 2009	156,894	115,566
December 31, 2010 and later	402,522	280,722
Other(1)	348,146	211,920
Total	959,958	651,308

(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		Six Months Ended June 30, 2007	
	Gross	**Net**	**Gross**	**Net**
Development:				
Productive	82	50.8	104	69.4
Dry	5	2.5	1	1.0
Exploratory:				
Productive	19	13.0	2	1.5
Dry	6	5.0	2	1.5
Total:				
Productive	101	63.8	106	70.9
Dry	11	7.5	3	2.5

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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 August 15, 2007	
Area	**Owned(1)**	**Third Party**	**Owned(1)**	**Third Party**
WTO	9		26	4
East Texas		2		5
Gulf Coast		1		
Other	1		2	1
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 six months ended June 30, 2007 and each company s approximate percentage of total sales during that period are listed below:

Gas Purchasers	**%**
Magnus Energy Marketing, Ltd.	20.4%
Atmos Energy Corporation	19.9%
ANP Funding I, LLC	16.9%
City of Austin, Texas	11.9%
El Paso Industrial Energy, LP	10.5%

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.

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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, 28 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,			Six Months Ended June 30,	
	2004	**2005**	**2006**	**2006**	**2007**
Number of operational rigs owned at end of period	10	19	25	21	27(3)
Average number of operational rigs owned during the period	8	14.3	21.9	20.3	25.5(3)
Average number of rigs utilized	8	14.3	21.9	20.3	23.2
Utilization rate	100%	100%	100%	100%	91%
Average drilling revenue per day(1)(2)	$ 73,023	$ 164,495	$ 373,051	$ 347,062	$ 398,872
Average drilling revenue per rig per day(2)	$ 9,128	$ 11,503	$ 17,034	$ 17,071	$ 17,193
Total footage drilled (feet in thousands)	635,684	1,749,700	2,124,079	1,149,342	873,861
Number of wells drilled	159	249	379	200	134

(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.

The table below identifies certain information concerning our drilling rigs as of August 15, 2007:

	Owned	Operational	Operating for SandRidge	Operating for Third Parties
Lariat	32(1)	27	21	4
Larclay	12(2)	11	7	4
Total	44	38	28	8

(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 2007 related to our oil field services are $115 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 six months ended June 30, 2007, we generated revenues of $23.3 million, for drilling services performed for third-parties, with Mariner Energy, Inc. accounting for $14.3 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 June 30, 2007:

ROC Gas Operated Plants	**Plant Capacity (Mmcf/d)**	**Average Utilization(1)**	**Third Party Usage**
Pike s Peak(2)	58	90.0%	1 .0%
Grey Ranch(3)	72	89.5%	34.2%
Sagebrush(4)	50	14.9%	10.2%

(1) Average utilization for six months ended June 30, 2007.

(2) A project to expand Pike s Peak capacity to 70 Mmcf per day is planned for completion by the fourth quarter of 2007.

(3) The Grey Ranch plant is operated by Southern Union. A project to expand the plant to 90 Mmcf/d will be completed during the fourth quarter of 2007. The plant capacity can be further increased to 160 Mmcf/d with additional capital improvements.

(4) Sagebrush commenced processing operations on May 1, 2007. Current throughput is 19 Mmcf per day, increasing utilization to 37.6%.

PetroSource Facilities	**CO_2 Compression Capacity (Mmcf/d)**	**Average Utilization(1)**
Pike s Peak	38	59.7%
Mitchell	26	4.2%
Grey Ranch	40	60.9%
Terrell	38	54.8%

(1) Average utilization for six months ended June 30, 2007.

West Texas

In Pecos County, we operate and own 92.5% of the Pike s Peak gas treating plant, which has the capacity to treat 58 Mmcf per day of gas for the removal of CO_2 from natural gas produced in the Piñon Field and nearby areas. We intend to expand Pike s Peak s capacity to 70 Mmcf per day during the fourth quarter of 2007. 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 72 Mmcf per day of gas. A project to increase the plant capacity to 90 Mmcf per day will be completed during the third quarter of 2007. Further expansion to 160 Mmcf per day may be accomplished with additional capital expenditures. 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 275 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 231 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 and we will either construct our own treating facilities,

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purchase Grey Ranch or renegotiate a long-term lease extension. 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.

Approximately 90% of the produced natural gas gathered by our midstream assets in West Texas requires compression from the wellhead to the final sales meter. We began replacing third-party rental compression through ROC Gas in 2003. ROC Gas currently owns and operates approximately 27,000 horsepower of gas compression and that number will grow to approximately 53,000 horsepower by the end of 2007.

Other Areas

Our Piceance Basin system consists of 50 Mmcf per day of processing plants and approximately 53 miles of pipeline gathering systems. 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 65 miles of pipeline gathering systems 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 approximately 26,000 horsepower of additional compression by the end of 2007. These new units will provide surplus capacity and allow us to provide stable, low pressures to maximize the deliverability of our wells. We also intend to install over 40 miles of large diameter pipeline and implement treating expansions in the Piñon Field, which we expect to be operational by the fourth quarter of 2007.

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.

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 88,000 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 90 Mmcf per day of CO_2 in available supply. We currently deliver the majority of this supply to Occidental Permian Ltd. and Pure Resources L.P. In July 2007, we captured and sold 86 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). Recently, a number of states of the U.S. have passed laws, adopted regulations or undertaken regulatory initiatives to 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. Other nations (not including 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.

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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, imposes 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 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 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 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.

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. 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 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 or limit our development of natural gas and oil projects.

Other Laws and Regulations

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. In addition, several states have declined to wait on Congress to develop and implement climate control legislation and have already taken legal measures to reduce emissions of greenhouse gases. 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. Other 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.

New and more stringent laws and regulations concerning the security of industrial facilities, including natural gas and oil facilities could be adopted in the future. Our operations may in the future be subject to such laws and regulations. Presently, it is not possible to accurately estimate the costs we could incur to comply with any such facility security laws or regulations, but such expenditures could be substantial.

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.

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

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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 September 30, 2007.

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	48	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	Vice President Accounting
Bill Gilliland	69	Director
Dan Jordan	50	Director
Roy T. Oliver, Jr.	55	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 Meinders School of Business in 1993. A founding board member for the University of Oklahoma Football

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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 (Vice President Accounting) Mr. Cooley has served as our Vice President, Accounting since November 2006, upon the closing of the NEG acquisition. Prior to joining SandRidge, Mr. Cooley served as the senior financial officer with National Energy Group, Inc. until the time of the NEG acquisition, most recently as Vice President and Chief Financial Officer. From 1989 until 2001, Mr. Cooley was Vice President, Controller and Chief Financial Officer for Shana Petroleum Company. He began his career in 1978 with Pennzoil Oil Company in Houston. From 1980 until 1984, he was employed in public accounting and from 1984 until 1989, he was controller for Rebel Drilling Company and Wildcat Well Service. 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.

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.

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 six directors, Messrs. Ward, Gilliland, Jordan, Oliver, Scott and Serota. We are not currently required to comply with the corporate governance rules of any stock exchange and, as a private company, we are not currently subject to many of the provisions of the Sarbanes-

Oxley Act of 2002 and related SEC rules (collectively, Sarbanes-Oxley). However, upon the effectiveness of the registration statement related to this prospectus, we will become subject to all of the provisions of Sarbanes-Oxley. If, as we anticipate, our common stock becomes listed on the New York Stock Exchange, a majority of our directors will be required to meet standards of independence. We believe that Messrs. Oliver, Scott and Serota currently meet these independence standards and intend to appoint an additional independent director in order to comply with the listing requirements of the New York Stock Exchange.

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 director is Mr. Jordan. 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. 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 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. Mr. 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. We do not currently have a compensation committee. During the last fiscal year, both Mr. Ward, our Chairman, Chief Executive Officer and President, and Mr. Mitchell, our former 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 2006, 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.

From January 1, 2006 to July 10, 2006, each of our non-employee directors received an annual retainer of $30,000 and $1,000 per board meeting attended in person. Directors who also served as employees during this period received no compensation for serving on our board of directors.

The following table sets forth the aggregate compensation awarded to, earned by or paid to our directors during 2006.

Name	Fees Earned or Paid in Cash	Stock Awards	Total
Bill Gilliland	$ 78,000(1)	$ 14,385(3)	$ 92,385
Dan Jordan	$ 50,000(2)	$ 12,259(3)	$ 62,259
Roy T. Oliver, Jr.	$ 50,000(2)	$ 14,385(3)	$ 64,385

(1) Consists of (i) $50,000 received as a retainer for one year of service as a non-employee director, and (ii) $28,000 for attending three meetings before July 10, 2006 and two regular meetings following July 10, 2006.

(2) Consists of (i) $25,000 received as a retainer for six months of service as a non-employee director and (ii) $25,000 received for attending two regular meetings after July 10, 2006.

(3) Includes the dollar amount of compensation expense we recognized for the fiscal year ended December 31, 2006 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 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, 2006, the number of shares of stock held by each non-employee director was: Mr. Gilliland 1,348,489; Mr. Jordan 633,333 and Mr. Oliver 400,000.

Indemnification

We intend to enter 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 will 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 will 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 will also obligate us to promptly advance all reasonable expenses incurred in connection with any claim. The indemnitee will be, 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 will not be exclusive of any other indemnity rights; however, double payment to the indemnitee will be prohibited.

We will not be 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 will include coverage for losses for wrongful acts and omissions and to ensure our performance under the indemnification agreements. Each of the indemnitees will be 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 anticipate providing 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 once they have been adopted.

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
Former Officers:	
N. Malone Mitchell, 3rd	Former Chairman, Chief Executive Officer and President
John Gaines	Former Chief Financial Officer
Barbara Pope	Former Vice President, Accounting
Todd Dutton	Former Chief Operating Officer and Vice President Land
Matthew McCann	Former Senior Vice President Legal

Since our inception through June 2006, we were controlled by Mr. Mitchell, 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.

Setting Executive Compensation

Role of our Board and Executive Officers. Our board of directors does not currently have a separate compensation committee due to the size of our existing board of directors and the lack of independent directors. 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. In the future, our compensation committee will adjust executive compensation levels on a semi-annual basis based on the recommendations of Mr. Ward.

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

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 all of the compensation and benefit-based plans and programs in which our executive officers participate and adjusting such plans and programs based on our current management team and in anticipation of becoming a public company;
- 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 2006 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 will face as a public company. Due to our significant growth, our move from Amarillo, Texas to Oklahoma City, Oklahoma and our anticipated initial public offering, we have hired numerous new employees, including several of the named executive officers. These new hires have been made in a competitive compensation environment for highly qualified and experienced energy industry executives, frequently 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.

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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, 2006, 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 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.

Prior to June 2006, base salaries were established based primarily on each executive officer s responsibilities at the discretion of Mr. Mitchell. Base salary levels were competitive with employers of similar size in Amarillo, Texas and were adjusted from time to time at the discretion of Mr. Mitchell.

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 we focused on the effective execution of the NEG acquisition, successful access to capital to fund our capital expenditures 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.

For 2006, Messrs. Ward, Van Doren, Grubb, Dutton and McCann each received a cash bonus payment as reflected in the Bonus column of the Summary Compensation Table.

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 our employees for his personal investments and activities. 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 wages or salary. Employees contributions are immediately 100% vested; however, company contributions vest in equal annual increments over a four-year period.

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 Agreement of Tom L. Ward. We maintain an employment agreement with our Chairman, Chief Executive Officer and President, Mr. Ward, to ensure that he will perform his role for an extended period of time. This agreement is described in more detail elsewhere. Please read Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table Employment Agreements Employment Agreement of Tom L. Ward. This agreement provides for severance compensation to be paid if the employment of Mr. Ward is terminated under certain conditions, such as a change in control and termination without cause, each as defined in the agreement.

The employment agreement between us and Mr. Ward 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 if his employment is terminated following a change in control transaction to promote the ability of Mr. Ward to act

in the best interests of our stockholders even though his employment could be terminated as a result of the transaction.

Termination without Cause. If we terminate Mr. Ward s employment without cause, we are obligated to pay him 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 and Mr. Ward to have mutually agreed to a severance package that is 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.

Employment Agreement of N. Malone Mitchell, 3rd. Prior to his resignation effective at the completion 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 was terminated upon his resignation.

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. See Employment Agreements Other Executive Officers. We intend to enter into additional employment agreements and severance plans with other executive officers during 2007.

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 offering price of our common stock, Mr. Ward must continue to beneficially own at least 228,621 shares of our common stock. Because Mr. Ward beneficially owns in excess of 31 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 have 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.

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.

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.

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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 year ended December 31, 2006.

Summary Compensation Table for the Year Ended December 31, 2006

Name and Principal Position	Year	Salary	Bonus	Stock Awards(9)	All Other Compensation(10)	Total
Current Officers:						
Tom L. Ward *Chairman, Chief Executive Officer and President*(1)	2006	$ 526,154	$ 950,000		$ 374,657	$ 1,850,811
Dirk M. Van Doren *Executive Vice President and Chief Financial Officer*(2)	2006	$ 251,923	$ 225,000	$ 72,512	$ 7,961	$ 557,396
Matthew K. Grubb *Executive Vice President and Chief Operating Officer*(3)	2006	$ 136,250	$ 307,000	$ 34,226	$ 8,944	$ 486,420
Former Officers:						
N. Malone Mitchell, 3rd *Former Chairman, Chief Executive Officer and President*(4)	2006	$ 611,539			$ 137,692	$ 749,231
John Gaines *Former Chief Financial Officer*(5)	2006	$ 89,423		$ 1,437,494	$ 72,739	$ 1,599,656
Barbara Pope *Former Vice President, Accounting*(6)	2006	$ 103,958		$ 2,109,000	$ 136,391	$ 2,349,349
Todd Dutton *Former Chief Operating Officer and Vice President Land*(7)	2006	$ 237,021	$ 10,000	$ 377,914	$ 92,502	$ 717,437
Matthew McCann *Former Senior Vice President Legal*(8)	2006	$ 183,173	$ 100,000	$ 377,914	$ 72,877	$ 733,964

(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. Mitchell served as our Chairman, Chief Executive Officer and President until June 8, 2006. Following this date, Mr. Mitchell served as our President and Chief Operating Officer until his resignation as an executive officer, effective as of December 31, 2006. Mr. Mitchell continued to serve as one of our directors until his resignation in September 2007.

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(5) Mr. Gaines served as our Chief Financial Officer until June 8, 2006. Upon Mr. Gaines resignation, the board of directors elected to accelerate the vesting of 83,333 shares of restricted stock held by Mr. Gaines.

(6) Ms. Pope served as our Vice President, Accounting until August 31, 2006. Upon Ms. Pope s resignation, the board of directors elected to accelerate the vesting of 111,000 shares of restricted stock held by Ms. Pope.

(7) Mr. Dutton served as our Chief Operating Officer until June 2006 and as Vice President Land until September 2006.

(8) Mr. McCann served as our Senior Vice President Legal until May 7, 2007.

(9) This column includes the dollar amount of compensation expense we recognized for the fiscal year ended December 31, 2006 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.

(10) All Other Compensation consists of the following:

Club Membership	Accounting	Aircraft	Life Insurance	Company Matching Contributions to	Relocation Expenses	Retention or Severance	Employee Participation Plan Participation