SANDRIDGE ENERGY INC
Form 424B1
November 06, 2007

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Filed Pursuant to Rule 424(b)(1)
Registration No. 333-144004

PROSPECTUS

28,700,000 Shares

SandRidge Energy, Inc.

Common Stock

We are offering 28,700,000 shares of our common stock. We are offering 4,170,000 of these shares at the public offering price directly to an entity controlled by Tom L. Ward, our Chairman, Chief Executive Officer and largest stockholder. Mr. Ward is not currently obligated to purchase these shares. This is our initial public offering, and no public market currently exists for our common stock.

Our common stock has been approved for listing 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.

	Per Share	Total
Public offering price	$ 26.00	$ 746,200,000
Underwriting discounts(1)	$ 1.56	$ 38,266,800
Proceeds to SandRidge Energy, Inc.(1) (before expenses)	$ 24.44	$ 707,933,200

(1) The underwriters will not receive any underwriting discount or commission on the 4,170,000 shares offered directly to an entity controlled by Tom L. Ward. See Underwriting.

We have granted the underwriters a 30-day option to purchase up to an additional 3,679,500 shares from us on the same terms and conditions as set forth above if the underwriters sell more than 24,530,000 shares of common stock in this offering.

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.

Lehman Brothers, on behalf of the underwriters, expects to deliver the shares on or about November 9, 2007.

Lehman Brothers

Goldman, Sachs & Co.

Banc of America Securities LLC

Bear, Stearns & Co. Inc.

Credit Suisse

Deutsche Bank Securities

JPMorgan

UBS Investment Bank

Howard Weil Incorporated

Raymond James

RBC Capital Markets

Simmons & Company International

TudorPickering

November 5, 2007

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You should rely only on the information contained in this prospectus or to which we have referred you. We have not, and the underwriters have not, authorized anyone to provide you with different information. We 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.

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.

Through and including November 30, 2007 (the 25th day after the date of this prospectus), all dealers effecting transactions in our common stock, whether or not participating in this offering, may be required to deliver a prospectus. This is in addition to the dealers obligation to deliver a prospectus when acting as underwriters and with respect to their unsold allotments or subscriptions.

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. and its subsidiaries after the merger and its predecessor, Riata Energy, Inc., and its subsidiaries prior to the merger.

Overview

SandRidge is a rapidly growing 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 described below, 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 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 whom have experience at public exploration and production companies. We have also added key professionals in exploration, operations, land, accounting and finance.

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

Our estimated capital expenditures for 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.

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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 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 will own 38.4% of our capital stock on a fully-diluted basis following the completion of this offering, 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.

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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	105.7	416.4	35.0	8.3	53,464	34,765	51
Other(4)	263.7	641.3	38.9	18.6	358,281	179,589	1,298(5)
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 and other items 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 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.

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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

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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, 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.

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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 SandRidge Energy, Inc.(1)(2)	28,700,000 shares
Common stock outstanding immediately prior to the completion of this offering(1)(3)	109,471,022 shares
Common stock to be outstanding immediately after the completion of this offering(1)(3)	138,171,022 shares
Use of proceeds	We will receive net proceeds from the sale of the common stock offered by us of approximately $705.4 million after deducting the estimated expenses and underwriting discounts and commissions. We intend to use the net proceeds to repay (i) the outstanding balance on our senior credit facility, which balance as of October 12, 2007 was $455 million prior to the application of available cash balances and (ii) a $50 million note incurred in connection with our recent acquisition in the WTO. We intend to use the remaining proceeds to fund the remaining unfunded portion of our $1,200 million capital expenditure budget for 2007. Please read Use of Proceeds and Underwriting.
Dividend policy	We do not anticipate that we will pay cash dividends on our common stock in the foreseeable future.
New York Stock Exchange Symbol	SD

(1) Assumes no exercise of the underwriters over-allotment option. See Underwriting.

(2) Includes 4,170,000 shares to be offered directly to an entity controlled by Mr. Ward, our Chairman, Chief Executive Officer and President, at the initial public offering price.

(3) These shares exclude 22,275,871 shares issuable upon conversion of our outstanding 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 June 30, 2007 and for the six months ended June 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,			Six Months Ended June 30,		Six Months Ended June 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	$ 173,830	$ 308,127	$ 291,370	$ 565,256
Expenses:							
Production	10,230	16,195	35,149	13,665	49,018	38,993	84,895
Production taxes	2,497	3,158	4,654	1,529	7,926	3,833	9,770
Drilling and services	26,442	52,122	98,436	47,685	24,126	38,146	77,453
Midstream and marketing	96,180	141,372	115,076	58,386	46,747	29,205	66,848
Depreciation, depletion and amortization natural gas and crude oil	4,909	9,313	26,321	7,868	70,699	114,284	217,013
Depreciation, depletion and amortization other	7,765	14,893	29,305	13,808	22,263	14,030	29,701
General and administrative	6,554	11,908	55,634	20,303	25,360	25,754	67,629
Loss (gain) on derivative contracts	878	4,132	(12,291)	(10,579)	(15,981)	(49,504)	(111,998)
Loss (gain) on sale of assets	(210)	547	(1,023)		(659)		(1,023)

Total expenses	155,245	253,640	351,261	152,665	229,499	214,741	440,288
Income from operations	20,750	34,053	36,981	21,165	78,628	76,629	124,968
Other income (expense):							
Interest income	56	206	1,109	397	3,626	3,352	5,984
Interest expense	(1,678)	(5,277)	(16,904)	(1,584)	(60,108)	(37,581)	(74,056)
Minority interest	(262)	(737)	(296)	(99)	(157)	12	(185)
Income (loss) from equity investments	(36)	(384)	967	(697)	2,164	(697)	967
Total other income (expense)	(1,920)	(6,192)	(15,124)	(1,983)	(54,475)	(34,914)	(67,290)
Income before income taxes	18,830	27,861	21,857	19,182	24,153	41,715	57,678
Income tax expense	6,433	9,968	6,236	5,150	9,082	15,435	21,341
Income from continuing operations	12,397	17,893	15,621	14,032	15,071	26,280	36,337
Income from discontinued operations, net of tax	451	229					
Extraordinary gain	12,544						
Net income	25,392	18,122	15,621	14,032	15,071	26,280	36,337
Preferred stock dividends and accretion			3,967		21,260	18,103	40,174
Income (loss) available (applicable) to common stockholders	$ 25,392	$ 18,122	$ 11,654	$ 14,032	$ (6,189)	$ 8,177	$ (3,837)

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	Historical					Pro Forma	
	Years Ended December 31,			Six Months Ended June 30,		Six Months Ended June 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	$ 0.20	$ 0.15	$ 0.23	$ 0.31
Income from discontinued operations, net of income tax	0.01	0.01					
Extraordinary gain on acquisition	0.22						
Preferred stock dividends			(0.05)		(0.21)	(0.16)	(0.34)
Income (loss) per share available (applicable) to common stockholders	$ 0.45	$ 0.32	$ 0.16	$ 0.20	$ (0.06)	$ 0.07	$ (0.03)
Weighted average number of shares outstanding(2):	56,312	56,559	73,727	71,596	100,025	118,745	118,746
Diluted							
Income from continuing operations	$ 0.22	$ 0.31	$ 0.21	$ 0.19	$ 0.15	$ 0.23	$ 0.31
Income from discontinued operations, net of income tax	0.01	0.01					
Extraordinary gain on acquisition	0.22						
Preferred stock dividends			(0.05)		(0.21)	(0.16)	(0.34)
Income (loss) per share available (applicable) to common stockholders	$ 0.45	$ 0.32	$ 0.16	$ 0.19	$ (0.06)	$ 0.07	$ (0.03)

Weighted average number of outstanding shares(2):	56,312	56,737	74,664	72,540	100,025	119,689	119,683

(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 June 30,
	2005	2006	2007
	(In thousands)		
Balance Sheet Data:			
Cash and cash equivalents	$ 45,731	$ 38,948	$ 2,199
Property, plant and equipment, net	$ 337,881	$ 2,134,718	$ 2,542,460
Total assets	$ 458,683	$ 2,388,384	$ 2,765,348
Long-term debt	$ 43,133	$ 1,066,831	$ 1,066,656
Redeemable convertible preferred stock	$	$ 439,643	$ 449,998
Total stockholders equity	$ 289,002	$ 649,818	$ 950,821
Total liabilities and stockholders equity	$ 458,683	$ 2,388,384	$ 2,765,348

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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.

(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 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,			Six Months Ended June 30,	
	2004	2005	2006	2006	2007
Production Data:					
Natural Gas (Mmcf)	6,708	6,873	13,410	4,219	22,292
Oil (MBbls)	37	72	322	46	906
Combined Equivalent Volumes (Mmcfe)	6,930	7,305	15,342	4,495	27,728
Average Daily Combined Equivalent Volumes (Mmcfe/d)	18.9	20.0	42.0	24.8	153.2

Our average daily combined equivalent volumes of production for the month of September 2007 was 191.2 Mmcfe per day.

	Year Ended December 31,			Six Months Ended June 30,	
	2004	2005	2006	2006	2007
Average Prices(1):					
Natural Gas (per Mcf)	$ 4.43	$ 6.54	$ 6.19	$ 6.08	$ 6.90
Oil (per Bbl)	$ 34.03	$ 48.19	$ 56.61	$ 62.99	$ 58.18
Combined Equivalent (per Mcfe)	$ 4.47	$ 6.63	$ 6.60	$ 6.35	$ 7.45

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

	Year Ended December 31,			Six Months Ended June 30,	
	2004	2005	2006	2006	2007
Expenses per Mcfe:					
Lease operating expenses:					
Transportation	$ 0.14	$ 0.16	$ 0.22	$ 0.22	$ 0.17
Processing and gathering(1)	0.39	0.42	0.37	0.53	0.25
Other lease operating expenses	0.94	1.64	1.70	2.29	1.34

Total lease operating expenses	$ 1.48	$ 2.22	$ 2.29	$ 3.04	$ 1.77
Production taxes	$ 0.36	$ 0.43	$ 0.30	$ 0.34	$ 0.29

(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

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or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from the well or abandonment of the well. From January 1, 2007 through 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 June 30, 2007, our total indebtedness was $1.1 billion, which represented approximately 43% 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

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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 this Offering and Our Common Stock

Certain stockholders shares are restricted from immediate resale but may be sold into the market in the near future. This could cause the market price of our common stock to drop significantly.

After this offering, 138,171,022 shares of common stock will be outstanding, or 141,850,522 shares if the underwriters exercise their over-allotment option in full. Of these 138,171,022 shares, the 28,700,000 shares sold in this offering, or 32,379,500 shares if the underwriters exercise their over-allotment option in full, will be freely tradable without restriction under the Securities Act except for any shares purchased by one of our

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affiliates as defined in Rule 144 under the Securities Act. In addition, holders of 2,184,287 shares of our convertible preferred stock may convert such shares to common stock at any time. Following this offering and assuming the conversion of all outstanding shares of convertible preferred stock, 160,446,893 shares of common stock would be outstanding, or 164,126,393 shares if the underwriters exercise their over-allotment option in full. All of the shares outstanding other than the shares sold in this offering (a total of 109,471,022 shares) are restricted securities with the meaning of Rule 144 under the Securities Act.

In connection with this offering, we, all of our executive officers and directors, and N. Malone Mitchell, 3rd, have entered into lock-up agreements with Lehman Brothers Inc., Goldman, Sachs & Co. and Banc of America Securities LLC under which such holders of restricted shares have agreed that, subject to certain exceptions, they will not, directly or indirectly, offer, sell, contract to sell, pledge or otherwise dispose of or hedge any common stock or securities convertible into or exchangeable for shares of common stock, or publicly announce the intention to do any of the foregoing, without the prior written consent of the underwriters for a period of 180 days from the date of this prospectus. See Underwriting for a description of these lock-up arrangements. The lock-up agreement that Mr. Ward, our Chairman, Chief Executive Officer and President, entered into contains an exception for approximately 6,584,098 restricted shares of our common stock that he has pledged as a portion of the collateral for a personal loan and any additional shares of our common stock that he may pledge as collateral for such loan. If Mr. Ward defaults on this loan, the lender may foreclose on and sell these shares pursuant to an exemption under the Securities Act notwithstanding the lock-up agreement. The lock-up agreement of Mr. Mitchell, our former Chairman, Chief Executive Officer and President, allows him to pledge up to all of his common shares as collateral for a personal loan provided that the lender agrees to be bound by the terms of Mr. Mitchell s lock-up with respect to any shares that are transferred to the lender as a result of foreclosure. There are additional restrictions on the transfer of shares by Messrs. Ward and Mitchell contained in the Amended and Restated Shareholders Agreement, dated as of April 4, 2007. The Amended and Restated Shareholders Agreement, however, also permits Messrs. Ward and Mitchell to pledge their shares, subject to certain conditions, in connection with a bona fide loan. See Description of Capital Stock Registration Rights Amended and Restated Shareholders Agreement.

Stockholders who acquired securities in our December 2005, November 2006 or March 2007 private placements are subject to lock-up provisions contained in the registration rights agreements entered into in connection with such private placements. Pursuant to these lock-up provisions, as amended, these stockholders may not, directly or indirectly, offer, sell, contract to sell, pledge or otherwise dispose of or hedge any common stock or securities convertible into or exchangeable for shares of common stock, or publicly announce the intention to do any of the foregoing, for a period from the date of this prospectus until the later of (i) 60 days following the date of this prospectus and (ii) January 1, 2008. These lock-up provisions do not apply to securities purchased in this offering or following the completion of this offering.

Shareholders party to the Amended and Restated Shareholders Agreement, including Mr. Ward, Mr. Mitchell and entities affiliated with Ares Management Fund LLC, have agreed not to effect any sale or distribution of our equity securities or securities convertible into or exchangeable or exercisable for any of our equity securities for a period of 180 days from the date of this prospectus. See Underwriting for a description of these lock-up agreements.

Giving effect to these lock-up agreements (but excluding the effect of the exclusion for Mr. Ward s pledged shares), the 109,471,022 restricted shares outstanding immediately prior to this offering will be eligible for sale in the public market under Rule 144 of the Securities Act, subject to volume limitations and other restrictions contained in Rule 144, as follows: (i) at the date of this prospectus 4,962,715 shares, (ii) commencing on the later of (a) 60 days thereafter and (b) January 1, 2008, an additional 21,312,313 shares, and (iii) commencing 180 days thereafter an additional 83,195,994 shares.

We have filed a shelf registration statement to register the resale, from time to time, of up to 62,036,000 shares of our common stock sold in or issuable upon the conversion of securities sold in our December 2005, November 2006 and March 2007 private placements. We anticipate that this shelf registration statement will be declared effective in the fourth quarter of 2007. All of the shares to be registered by the shelf registration statement are subject to the lock-up provisions described above related to our private placements. We may also

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register certain shares issued or reserved for issuance under our stock option plans. Please read Shares Eligible for Future Sale.

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

There has been no active trading market for our common stock, and an active trading market may not develop.

Prior to this offering, there has been no public market for our common stock. Our common stock has been approved for listing on the New York Stock Exchange. We do not know if an active trading market will develop for our common stock or how the common stock will trade in the future, which may make it more difficult for you to sell your shares. Negotiations between the underwriters and us determined the initial public offering price. You may not be able to resell your shares at or above the initial public offering price.

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 million shares of common stock and 50 million shares of preferred stock with preferences and rights as determined by our Board of Directors. Immediately prior to the closing of this offering, we will have approximately 2.2 million shares of common stock outstanding pursuant to our stock incentive plan, we have also reserved approximately 4.9 million shares of our common stock for future issuance as restricted stock, stock options or other equity-based grants to employees and directors. We may also issue additional shares of our common stock or other securities that are convertible into or exercisable for common stock in connection with the hiring of personnel, future acquisitions, future private placements of our securities for capital raising purposes or for other business purposes. We have 2,184,287 shares of convertible preferred stock outstanding, which may be converted into 22,275,871 shares of common stock at any time by the holders of such preferred stock or by us at any time following 180 days after the closing of this offering upon satisfaction of other conditions. See Description of Capital Stock Preferred Stock Convertible Preferred Stock. In addition, Mr. Ward, our Chairman, Chief Executive Officer and President, has pledged 6,584,098 restricted shares of our common stock as a portion of the collateral for a personal loan and may pledge additional shares in the future. If Mr. Ward defaults on this loan, the lender may foreclose on and sell these shares pursuant to an exemption under the Securities Act. The lock-up agreement of Mr. Mitchell, one of our directors, allows him to pledge up to all of his common shares as collateral for a personal loan provided that the lender agrees to be bound by the terms of Mr. Mitchell s lock-up with respect to any shares that are transferred to the lender as a result of foreclosure. There are additional restrictions on the transfer of shares by Messrs. Ward and Mitchell contained in the Amended and Restated Shareholders Agreement, dated as of April 4, 2007. The Amended and Restated Shareholders Agreement, however, also permits Messrs. Ward and Mitchell to pledge their shares, subject to certain conditions, in connection with a bona fide loan. See Description of Capital Stock Registration Rights Amended and Restated Shareholders Agreement. At the closing of this offering, 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

We will receive net proceeds from the sale of 28,700,000 shares of the common stock offered by us of approximately $705.4 million after deducting estimated expenses and underwriting discounts and commissions of $40.8 million.

We intend to use the net proceeds to repay the outstanding balance on our senior credit facility, which balance as of October 12, 2007 was $455.0 million, prior to the application of available cash balances. Affiliates of Banc of America Securities LLC, Credit Suisse Securities (USA) LLC, Deutsche Bank Securities Inc., and RBC Capital Markets Corporation are lenders under our senior credit facility. These borrowings were incurred primarily to fund capital expenditures in connection with our accelerated drilling program and the expansion of our midstream capacity. Our senior credit facility matures November 21, 2011 and bore interest at a rate of 6.92% per annum as of September 30, 2007. We also intend to use a portion of the net proceeds to repay a $50.0 million note we incurred in connection with our recent acquisition in the WTO. This note matures on September 30, 2008 and bears interest at 7.00% per annum. Please see Business Recent WTO Acquisition for a description of this acquisition. We intend to use the remaining proceeds to fund the remaining unfunded portion of our $1,200 million capital expenditures budget for 2007, including $943 million in exploration and development (including land and seismic acquisitions and our tertiary recovery operations), $115 million in drilling and oilfield services and $103 million in midstream operations. We intend to fund the remaining capital expenditures from cash on hand and additional borrowings under our senior credit facility. Please see Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

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.

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CAPITALIZATION

The following table sets forth, as of June 30, 2007, a summary of our capitalization, both on an actual basis and on an as adjusted basis to give effect to the sale by us of 28,700,000 shares at an initial public offering price of $26.00 per share and the application of the net proceeds as set forth under Use of Proceeds.

You should read the following table in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and our consolidated financial statements and related notes thereto appearing elsewhere in this prospectus.

	As of June 30, 2007	
	Actual	As Adjusted
	(In thousands)	
Cash and cash equivalents(1)	$ 2,199	$ 707,632
Long term debt, including current maturities:		
Revolving credit facility(1)		
Senior term loan	1,000,000	1,000,000
Other long term debt	66,656	66,656
Minority interest	5,772	5,772
Convertible preferred stock, $0.001 par value; 2,650,000 shares authorized; 2,184,287 shares issued and outstanding	449,998	449,998
Stockholders equity:		
Common stock, $0.001 par value; 400,000,000 shares authorized; 110,311,000 issued and 108,859,000 outstanding (actual), 139,011,000 shares issued and 137,559,000 outstanding (as adjusted)	109	138
Preferred stock, no par value; 50,000,000 shares authorized, no shares issued and outstanding		
Additional paid-in capital	886,508	1,591,913
Retained earnings	82,694	82,694
Treasury stock, at cost	(18,490)	(18,490)
Total stockholders equity	950,821	1,656,255
Total capitalization	$ 2,473,247	$ 3,178,681

(1) At October 12, 2007, we had $455.0 million outstanding on our revolving credit facility, prior to application of available cash balances, and an additional $50.0 million note incurred in connection with a recent acquisition. We intend to use a portion of the proceeds of this offering to repay this debt. Please see Use of Proceeds.

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DILUTION

Our net tangible book value as of June 30, 2007 was approximately $921.6 million or $8.47 per share of common stock. Net tangible book value per share is determined by dividing our tangible net worth (tangible assets less total liabilities) by the total number of outstanding shares of common stock that will be outstanding immediately prior to the closing of this offering. After giving effect to the sale of the shares in this offering and assuming the receipt of the estimated net proceeds (after deducting estimated discounts and expenses of this offering), our adjusted net tangible book value as of June 30, 2007 would have been approximately $1,627.1 million or $11.83 per share. This represents an immediate increase in the net tangible book value of $3.36 per share to our existing stockholders and an immediate dilution (i.e., the difference between the offering price and the pro forma net tangible book value after this offering) to new investors purchasing shares in this offering of $14.17 per share. The following table illustrates the per share dilution to new investors purchasing shares in this offering:

Offering price per share		$ 26.00
Net tangible book value per share at June 30, 2007	$ 8.47	
Increase per share attributable to new investors	3.36	
Adjusted net tangible book value per share after this offering		11.83
Dilution per share to new investors		$ 14.17

The following table summarizes, on an as adjusted basis as of June 30, 2007, the total number of shares of common stock owned by existing stockholders and to be owned by new investors, the total consideration paid, and the average price per share paid by our existing stockholders and to be paid by new investors in this offering at $26.00, calculated before deduction of estimated underwriting discounts and commissions.

	Shares Purchased(1)		Total Consideration		Average Price per Share
	Number	Percent	Amount	Percent	
Existing stockholders	113,029,000	82%	$ 982,427,000	61%	$ 8.69
New Public Investors	24,530,000	18%	637,780,000	39%	26.00
Total	137,559,000	100%	$ 1,620,207,000	100%	$ 11.78

(1) The number of shares disclosed for the existing stockholders includes 4,170,000 shares offered directly to TLW Properties, L.L.C., an entity controlled by Mr. Ward.

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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 and the issuance of 28,700,000 shares in this offering at an offering price of $26.00 per share. The unaudited pro forma condensed combined statements of operations information for the year ended December 31, 2006 and the six months ended June 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 six months ended June 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	26,321	91,611	99,081(a)(c)	217,013
Depreciation, depletion and amortization other	29,305	396		29,701
General and administrative	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 stock 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	45,019(h)(i)	118,746
Diluted	74,664	45,019(h)(i)	119,683

See Notes to Unaudited Pro Forma Condensed Combined Financial Information

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SandRidge Energy, Inc.

UNAUDITED PRO FORMA CONDENSED COMBINED STATEMENT OF OPERATIONS FOR THE SIX MONTHS ENDED JUNE 30, 2006

	SandRidge Energy Historical	NEG Historical (January 1, 2006 through June 30, 2006)	Pro Forma Adjustments	SandRidge Energy Pro Forma Combined
	(in thousands except per share data)			
Revenues	$ 173,830	$ 155,973	$ (38,433)(a)(b)	$ 291,370
Expenses:				
Production	13,665	24,596	732(a)(b)	38,993
Production taxes	1,529	2,304		3,833
Drilling and services	47,685		(9,539)(a)	38,146
Midstream and marketing	58,386		(29,181)(a)	29,205
Depreciation, depletion and amortization natural gas and crude oil	7,868	48,927	57,489(a)(c)	114,284
Depreciation, depletion and amortization other	13,808	222		14,030
General and administrative	20,303	7,039	(1,588)(a)	25,754
Gain on derivative contracts	(10,579)	(38,925)		(49,504)
Income from operations	21,165	111,810	(56,346)	76,629
Interest income	397	2,955		3,352
Interest expense	(1,584)	(10,525)	(25,472)(d)	(37,581)
Minority interest	(99)		111(e)	12
Loss from equity investments	(697)			(697)
Income before income tax provision	19,182	104,240	(81,707)	41,715
Income tax provision	5,150	1,712	8,573(f)	15,435
Income from continuing operations	14,032	102,528	(90,280)	26,280
Preferred stock dividends and accretion			18,103(g)	18,103
Income available to common stockholders	$ 14,032	$ 102,528	$ (108,383)	$ 8,177
Earnings per share available to common stockholders:				
Basic	$ 0.20			$ 0.07
Diluted	$ 0.19			$ 0.07

Number of shares used in calculating earnings per share:			
Basic	71,596	47,149(h)(i)	118,745
Diluted	72,540	47,149(h)(i)	119,689

See Notes to Unaudited Pro Forma Condensed Combined Financial Information

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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 six months ended June 30, 2006 give effect to the NEG acquisition and the other 2006 acquisitions and the related financing transactions and the issuance of 28,700,000 shares in this offering 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 June 30, 2006 for purposes of the pro forma condensed combined statement of operations for the six months ended June 30, 2006.

The unaudited pro forma condensed combined statements of operations for the year ended December 31, 2006 and the six months ended June 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 six months ended June 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 June 30, 2006.

(c) Reflects a $97.0 million and $55.5 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 June 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 cost will increase or decrease by approximately $0.4 million for the year ended December 31, 2006 and $0.3 million for the six months ended June 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 June 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

Six months ended June 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	(4)
	18,449

(i) Reflects the issuance of 28,700,000 shares in this offering.

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SELECTED CONSOLIDATED HISTORICAL FINANCIAL DATA

Set forth below is our selected consolidated historical financial data for the periods indicated. The historical statement of operations data for the periods ended December 31, 2002, 2003, 2004, 2005 and 2006 and the balance sheet data as of December 31, 2002, 2003, 2004, 2005 and 2006 have been derived from our audited financial statements. Our historical statement of operations data as of and for the six months ended June 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,					Six Months Ended June 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	$ 173,830	$ 308,127
Expenses:							
Production	7,949	7,980	10,230	16,195	35,149	13,665	49,018
Production taxes	661	2,099	2,497	3,158	4,654	1,529	7,926
Drilling and services	8,858	13,847	26,442	52,122	98,436	47,685	24,126
Midstream marketing	23,689	94,620	96,180	141,372	115,076	58,386	46,747
Depreciation, depletion and amortization natural gas and crude oil	3,142	3,298	4,909	9,313	26,321	7,868	70,699
Depreciation, depletion and amortization other	2,431	5,284	7,765	14,893	29,305	13,808	22,263
General and administrative	4,355	3,705	6,554	11,908	55,634	20,303	25,360
Loss (gain) on derivative contracts	3,193	3,450	878	4,132	(12,291)	(10,579)	(15,981)
Loss (gain) on sale of assets		(1,284)	(210)	547	(1,023)		(659)
Total operating expenses	54,278	132,999	155,245	253,640	351,261	152,665	229,499
Income from operations	4,969	22,338	20,750	34,053	36,981	21,165	78,628
Other income (expense):							

Interest income	84	103	56	206	1,109	397	3,626
Interest expense	(1,000)	(1,208)	(1,678)	(5,277)	(16,904)	(1,584)	(60,108)
Minority interest	(673)	(96)	(262)	(737)	(296)	(99)	(157)
Income (loss) from equity investments	304	1,056	(36)	(384)	967	(697)	2,164
Total other income (expense)	(1,285)	(145)	(1,920)	(6,192)	(15,124)	(1,983)	(54,475)
Income before income taxes	3,684	22,193	18,830	27,861	21,857	19,182	24,153
Income tax expense	1,334	7,585	6,433	9,968	6,236	5,150	9,082
Income from continuing operations	2,350	14,608	12,397	17,893	15,621	14,032	15,071
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	14,032	15,071
Preferred stock dividends and accretion					3,967		21,260
Income (loss) available (applicable) to common stockholders	$ 3,455	$ 12,887	$ 25,392	$ 18,122	$ 11,654	$ 14,032	$ (6,189)

	Historical						
	Years Ended December 31,					Six Months Ended June 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	$ 0.20	$ 0.15
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)		(0.21)
Income (loss) per share available (applicable) to common stockholders	$ 0.06	$ 0.23	$ 0.45	$ 0.32	$ 0.16	$ 0.20	$ (0.06)
Weighted average number of shares outstanding(3):	56,312	56,312	56,312	56,559	73,727	71,596	100,025
Diluted							
Income from continuing operations	$ 0.04	$ 0.26	$ 0.22	$ 0.31	$ 0.21	$ 0.19	$ 0.15
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)		(0.21)
Income (loss) per share available (applicable) to common stockholders	$ 0.06	$ 0.23	$ 0.45	$ 0.32	$ 0.16	$ 0.19	$ (0.06)
	56,312	56,312	56,312	56,737	74,664	72,540	100,025

Weighted average number of shares outstanding(3):

(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 June 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	$ 4,661	$ 2,199
Property, plant and equipment, net	$ 43,839	$ 70,289	$ 114,818	$ 337,881	$ 2,134,718	$ 479,694	$ 2,542,460
Total assets	$ 88,247	$ 127,744	$ 197,017	$ 458,683	$ 2,388,384	$ 560,465	$ 2,765,348
Long-term debt	$ 20,549	$ 24,740	$ 59,340	$ 43,133	$ 1,066,831	$ 88,260	$ 1,066,656
Redeemable convertible preferred stock	$	$	$	$	$ 439,643	$	$ 449,998
Total stockholders equity	$ 22,106	$ 33,940	$ 59,330	$ 289,002	$ 649,818	$ 298,634	$ 950,821
Total liabilities and stockholders equity	$ 88,247	$ 127,744	$ 197,017	$ 458,683	$ 2,388,384	$ 560,465	$ 2,765,348

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 growing 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 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 LLC, 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. For more information concerning our acquisition of NEG, see Business The NEG Acquisition.

The NEG acquisition, coupled with six acquisitions of additional working interests completed during 2006 and late 2005, have significantly increased our holdings in the WTO. We believe we have assembled the largest acreage position and that we are the largest operator and producer in the WTO. We also operate significant interests in the Cotton Valley Trend in East Texas and the Gulf Coast region.

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.

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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,			Six Months Ended June 30,	
	2004	2005	2006	2006	2007
	(In thousands)				
Segment revenue:					
Exploration and production	$ 37,564	$ 54,051	$ 106,413	$ 29,853	$ 207,305
Drilling and oil field services	39,211	80,151	138,657	70,324	40,228
Midstream gas services	99,044	147,499	122,892	61,890	52,100
Other	176	5,992	20,280	11,763	8,494
Total revenues	$ 175,995	$ 287,693	$ 388,242	$ 173,830	$ 308,127

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	Year Ended December 31, 2004	2005	2006	Six Months Ended June 30, 2006	2007
			(In thousands)		
Segment operating income:					
Exploration and production	14,000	14,886	17,069	7,962	76,463
Drilling and oil field services	4,206	18,295	32,946	17,025	8,876
Midstream gas services	2,636	4,096	3,528	1,777	2,301
Other	(92)	(3,224)	(16,562)	(5,599)	(9,012)
Total operating income	20,750	34,053	36,981	21,165	78,628
Interest income	56	206	1,109	397	3,626
Interest expense	(1,678)	(5,277)	(16,904)	(1,584)	(60,108)
Other income (expense)	(298)	(1,121)	671	(796)	2,007
Income before income taxes	$ 18,830	$ 27,861	$ 21,857	$ 19,182	$ 24,153

	Year Ended December 31, 2004	2005	2006	Six Months Ended June 30, 2006	2007
Production data:					
Gas (Mmcf)	6,708	6,873	13,410	4,219	22,292
Oil (MBbls)	37	72	322	46	906
Combined equivalent volumes (Mmcfe)	6,930	7,305	15,342	4,495	27,728
Daily combined equivalent volumes (Mmcfe/d)	18.9	20.0	42.0	24.8	153.2
Average prices(1):					
Natural gas (per Mcf)	$ 4.43	$ 6.54	$ 6.19	$ 6.08	$ 6.90
Oil (per Bbl)	$ 34.03	$ 48.19	$ 56.61	$ 62.99	$ 58.18
Combined equivalent (per Mcfe)	$ 4.47	$ 6.63	$ 6.60	$ 6.35	$ 7.45
Drilling and oil field services:					
Number of operational drilling rigs owned at end of period	10	19	25	21	27(3)
Average number of operational drilling rigs owned during the period	8.0	14.3	21.9	20.3	25.5(3)
Average total revenue per rig per day(2)	$ 9,128	$ 11,503	$ 17,034	$ 17,071	$ 17,193

(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 June 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 $207.3 million in the six months ended June 30, 2007 from $29.9 million in the six months ended June 30, 2006, an increase of 593%, as a result of a 517% increase in volumes and a 17% increase in the average price we received for the natural gas and oil we produced. In the six month period ended June 30, 2007 we increased production by 23.2 Bcfe, to 27.7 Bcfe. Natural gas production increased 18.1 Bcf or 428%. Of the 23.2 Bcfe increase, approximately 21.2 Bcfe of the increase was attributable to the properties acquired in the NEG acquisition, with the remainder of the increase due to our successful drilling in the WTO.

The average price we received for our natural gas and oil production for the six month period ended June 30, 2007 increased 17%, or $1.10 per Mcfe, to $7.45 per Mcfe from $6.35 per Mcfe in the comparable period in 2006. During late 2006 and continuing into 2007 we entered into derivatives contracts to mitigate the impact of commodity price fluctuations on our 2007 and 2008 production. Our derivatives contracts are not designated as accounting hedges and, as a result, gains or losses on derivatives contracts are recorded as an operating expense. Internally, our management views the settlement of such derivatives contracts as adjustments to the price received for natural gas and oil production to determine effective prices. Including the impact of derivative contract settlements, the effective price received for natural gas for the six month period ended June 30, 2007 was $6.86 per Mcf and $7.42 per Mcfe on a combined equivalent basis. Our derivatives contracts had no impact on effective oil prices during the six months ended June 30, 2007 or effective natural gas and oil prices received for the comparable period in 2006.

For the six months ended June 30, 2007, we had $76.5 million in operating income in our exploration and production segment, compared to $8.0 million operating income for the same period in 2006. Our $177.5 million increase in exploration and production revenues was offset by a $18.8 million increase in production expenses, and a $63.5 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 six month period ended June 30, 2007, the exploration and production segment reported a $16.0 million net gain on our derivatives positions ($16.8 million in unrealized gains and $0.8 million in realized losses) compared to $10.6 million in unrealized gains and no realized losses 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. 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 six month period ended June 30, 2007 was attributable to a decrease in average natural gas prices at June 30, 2007 as compared to the average natural gas prices at the various contract dates. Future volatility in natural gas and oil prices could have an adverse effect on the operating results of our exploration and production segment.

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.

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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 June 30, 2007 we had 1,174.0 Bcfe of estimated net proved reserves with an associated PV-10 of $2,558.8 million, representing an increase in reserves of 172.2 Bcfe from December 31, 2006. Approximately 78 Bcfe of this increase were added as a result of our successful drilling activity, approximately 14 Bcfe were added through acquisition and the remainder of the increase was due to revisions of estimates.

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 hour 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 June 30, 2007, 22 of our rigs were operating under daywork contracts.

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. We typically pay more of the out-of-pocket costs associated with footage contracts as compared to daywork contracts. The risks to us on a footage contract are greater because we assume most of the risks that are associated with drilling operations and that would normally be assumed by the operator in a daywork contract, including the risk of blowout, loss of hole, stuck drill pipe, machinery breakdowns, abnormal drilling conditions and risks associated with subcontractors services, supplies, cost escalation and personnel. As of June 30, 2007, none of our rigs were operating under footage contracts. We do not anticipate that a significant portion of our rigs will operate under footage contracts in the future.

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 technical expertise and engineering services, as well as 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 June 30, 2007, two of our rigs were operating under turnkey contracts.

Drilling and oil field services segment revenue decreased to $40.2 million in the six month period ended June 30, 2007 from $70.3 million in the six month period ended June 30, 2006. Operating income decreased to $8.9 million in the six month period ended June 30, 2007 from $17.0 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 83% in the wells we operate in the WTO, and the third party interest has declined to less than 20%. Approximately $11.9 million of the decrease in drilling and oil field services was due to the increase in our working interest and the number of wells drilled for our own account. The number of drilling rigs we owned increased 26% to an average of 25.5 rigs during the six month period ended June 30, 2007 from an average of 20.3 rigs in the comparable period in 2006. The average daily rate we received per rig of $17,193, excluding revenues for related rental equipment and before intercompany eliminations was essentially unchanged from the comparable period in 2006. Our rig utilization rate was 89%, representing 512 stacked rig days in 2007 as compared to 100% in the comparable period in 2006. The decrease in our rig utilization rate primarily resulted from the removal of two rigs from service for major refurbishment. 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 six months ended June 30, 2007 was $52.1 million compared to $61.9 million in the comparable period in 2006. The $9.8 million 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 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.

Subsequent Event

On July 11, 2007, we purchased property located in downtown Oklahoma City, Oklahoma to serve as our future corporate headquarters. The purchase price of the property was approximately $25 million in cash plus the assumption of an obligation to indemnify the sellers in connection with pending litigation involving the property. Payment of the purchase price was funded through borrowings under our senior credit facility. We intend to refinance these borrowings through a long-term mortgage during the fourth quarter of 2007.

Future Charges

Public Company Expenses

Following the completion of this offering, we will be a public company. We believe that our general and administrative expenses will increase in connection with becoming a public company. This increase will consist of legal and accounting fees and additional expenses associated with compliance with the Sarbanes-Oxley Act of 2002 and other regulations. Following the filing of a registration statement, we anticipate that our ongoing general and administrative expenses will also increase as a result of being a publicly traded company. This increase will be due to accounting support services, filing annual and quarterly reports with the SEC, investor relations, directors fees, directors and officers insurance and registrar and transfer agent fees. As a result, we believe that our general and administrative expenses for 2008 will significantly increase. Our consolidated financial statements following the completion of this offering will reflect the impact of these increased expenses and affect the comparability of our financial statements with periods prior to the completion of this offering.

Liquidated Damage Payments

In connection with our private placements in December 2005, November 2006 and March 2007, we entered into registration rights agreements that require us to use our commercially reasonable efforts to register the securities sold in such private placements by certain deadlines and to maintain effectiveness after registration. Generally, if we fail to have either registration statement declared effective within the specified time periods or fail to maintain an effective registration statement, we will be subject to liquidated damages payments. Please read Liquidated Damages Under Registration Rights Agreements. We have not accrued any reserves related to these potential payments.

Results of Operations

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2007

The financial information with respect to the six months ended June 30, 2006 and 2007 that is discussed below is unaudited. In the opinion of management, this information contains all adjustments, consisting only of normal recurring accruals, necessary for a fair presentation of the results for such periods. The results of operations for the interim periods are not necessarily indicative of the results of operations for the full fiscal year.

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Revenue. Total revenue increased 77% to $308.1 million for the six months ended June 30, 2007 from $173.8 million in the same period in 2006. This increase was due to a $177.9 million increase in natural gas and oil sales and was partially offset by lower revenues in our other segments.

	Six Months Ended June 30, 2006	Six Months Ended June 30, 2007	$ Change	% Change
	(In thousands)			
Revenue:				
Natural gas and crude oil	$ 28,563	$ 206,450	$ 177,887	622.8%
Drilling and services	69,971	40,244	(29,727)	(42.5)%
Midstream and marketing	61,892	52,101	(9,791)	(15.8)%
Other	13,404	9,332	(4,072)	(30.4)%
Total revenues	$ 173,830	$ 308,127	$ 134,297	77.3%

Total natural gas and crude oil revenues increased $177.9 million to $206.5 million for the six months ended June 30, 2007 compared to $28.6 million for the same period in 2006, primarily as a result of an increase in natural gas production volumes. Total natural gas production increased 428% to 22,292 Mmcf in 2007 compared to 4,219 Mmcf in 2006. Of the 18,073 Mmcf increase in natural gas production, approximately 16,162 Mmcf of the increase was attributable to the NEG acquisition. Average natural gas prices increased 13% in the 2007 period to $6.90 per Mcf compared to $6.08 per Mcf in 2006.

Drilling and services revenue decreased 43% to $40.2 million for the six months ended June 30, 2007 compared to $70.0 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. The number of rigs we owned increased to 25.5 (average for the six months ended June 30, 2007) in 2007 compared to 20.3 (average for the six months ended June 30, 2006) in 2006, an increase of 26%, and the average daily revenue per rig, after considering the effect of the elimination of intercompany usage, was essentially unchanged at $17,193 per day.

Midstream and marketing revenue decreased $9.8 million, or 16%, with revenues of $52.1 million in the six month period ended June 30, 2007 as compared to $61.9 million in the six month period ended June 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 $9.3 million for the six months ended June 30, 2007 from $13.4 million for the same period in 2006. The decrease was primarily due to the sale of Stockton Plaza, a commercial shopping center located in Fort Stockton, Texas. Stockton Plaza revenues are included in the 2006 period prior to its sale to Mr. Mitchell, our former Chairman, Chief Executive Officer and President, in August 2006. See Related Party Transactions.

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Operating Costs and Expenses. Total operating costs and expenses increased to $229.5 million for the six months ended June 30, 2007 compared to $152.7 million for the same period in 2006.

	Six Months Ended June 30,			
	2006	2007	$ Change	% Change
	(In thousands)			
Operating costs and expenses:				
Production	$ 13,665	$ 49,018	$ 35,353	258.7%
Production taxes	1,529	7,926	6,397	418.4%
Drilling and services	47,685	24,126	(23,559)	(49.4)%
Midstream and marketing	58,386	46,747	(11,639)	(19.9)%
Depreciation, depletion and amortization-natural gas and crude oil	7,868	70,699	62,831	798.6%
Depreciation, depletion and amortization-other	13,808	22,263	8,455	61.2%
General and administrative	20,303	25,360	5,057	24.9%
Gain on derivative instruments	(10,579)	(15,981)	(5,402)	(51.1)%
Gain on sale of assets		(659)	(659)	(100.0)%
Total operating costs and expenses	$ 152,665	$ 229,499	$ 76,834	50.3%

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 $35.4 million primarily due to a $23.2 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 $6.4 million, or 418%, to $7.9 million primarily due to the addition of the NEG properties in 2007.

Drilling and services and midstream and marketing expenses decreased 49% and 20% respectively, for the six months ended June 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 $70.7 million for the six months ended June 30, 2007 from $7.9 million in the same 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 516% to 27.7 Bcfe from 4.5 Bcfe in 2006. Our DD&A per Mcfe increased $0.80 to $2.55 from $1.75 in the comparable period 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 $5.1 million to $25.4 million for the six months ended June 30, 2007 from $20.3 million for the comparable period in 2006. The increase was principally attributable to a $6.7 million increase in corporate salaries and wages which was due to an increase in corporate staff, particularly more highly compensated employees. As of June 30, 2007, we had 2,052 employees as compared to 1,259 at June 30, 2006. The increase in salaries and wages was partially offset by a $2.2 million decrease in stock compensation expense. As part of an executive officer s resignation in 2006, the vesting period of certain restricted stock awards was modified resulting in increased compensation expense recognized in June 2006.

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For the six month period ended June 30, 2007, we recorded a gain of $16.0 million ($16.8 million unrealized gain) on our derivatives instruments compared to a $10.6 million unrealized 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. 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 six month period ended June 30, 2007 was attributable to a decrease in average natural gas prices at June 30, 2007 as compared to the average natural gas prices at the various contract dates.

Other Income (Expense). Total other expense increased to $54.5 million in the six month period ended June 30, 2007 from $2.0 million in the six month period ended June 30, 2006. The increase is reflected in the table below.

	Six Months Ended June 30, 2006	Six Months Ended June 30, 2007	$ Change	% Change
	(In thousands)			
Other income (expense):				
Interest income	$ 397	$ 3,626	$ 3,229	813.4%
Interest expense	(1,584)	(60,108)	(58,524)	(3,694.7)%
Minority interest	(99)	(157)	(58)	(58.6)%
Income (loss) from equity investments	(697)	2,164	2,861	410.5%
Total other expense	(1,983)	(54,475)	(52,492)	(2,647.1)%
Income before income taxes	19,182	24,153	4,971	25.9%
Income tax expense	5,150	9,082	3,932	76.3%
Net income	$ 14,032	$ 15,071	$ 1,039	7.4%

Interest income increased to $3.6 million for the six months ended June 30, 2007 from $0.4 million for the same period in 2006. This increase was due to interest income from excess cash in investment accounts.

Interest expense increased to $60.1 million for the six months ended June 30, 2007 from $1.6 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 senior unsecured term loan and sold 17.8 million shares of common stock in a private placement. A portion of the proceeds from the term loan and the private placement were used to repay the bridge loan. Please see Liquidity and Capital Resources.

Minority interest represents income attributable to the minority interest owners of Cholla Pipeline, Sagebrush Pipeline and Integra Energy.

During the six months ended June 30, 2007 we reported income from equity investments of $2.2 million as compared to a loss of $0.7 million 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 changed owners in 2006 and, after a change-over period, has been operating at a profit since the ownership change. Approximately $1.3 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 is operational.

We reported an income tax expense of $9.1 million for the six months ended June 30, 2007 from an expense of $5.2 million for the same period in 2006. The current period income tax expense represents an effective income tax rate of 37.6% as compared to 26.8% in the comparable period in 2006. The increase in our effective income tax rate was attributable to favorable percentage depletion in 2006.

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

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

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

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

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

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

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

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

	Year Ended December 31, 2005	Year Ended December 31, 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 increased our 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.

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.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Liquidity and Capital Resources

Summary

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

During 2006 and the first quarter of 2007, we entered into various debt and equity transactions to fund the acquisition of NEG and our 2007 capital expenditure program. As of June 30, 2007, our cash and cash equivalents were $2.2 million, and we had approximately $400 million available under our senior credit facility. As of October 12, 2007, we had $455 million outstanding under our senior credit facility, prior to the application of available cash. As of June 30, 2007, we had approximately $1,066.7 million in total debt outstanding, and our capital expenditures for the third and fourth quarters of 2007 are projected to be approximately $708 million.

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The NEG Acquisition

On November 21, 2006, we acquired all of the outstanding membership interest of NEG from AREP for approximately $990.4 million in cash, the assumption of $300 million in debt, the receipt of cash of $21.1 million and 12,842,000 shares of our common stock (valued at approximately $231.2 million).

To finance the NEG acquisition, we entered into a $750 million senior credit facility and an $850 million senior bridge facility. The $750 million senior credit facility had an initial borrowing capacity of $300 million. During 2007 the borrowing capacity was increased to $400 million. This revolving credit facility is collateralized by our natural gas and oil properties, except our Piceance Basin assets, and allows, but does not require any hedging. We also issued in a private placement $550 million of convertible preferred stock and common units consisting of shares of common stock and a warrant to purchase convertible preferred stock upon surrender of the common stock. The $850 million senior bridge facility was repaid in 2007 with the proceeds from the term loan and private placement of common stock described below.

Capital Expenditures

We make and expect to continue to make substantial capital expenditures in the exploration, development, production and acquisition of natural gas and oil reserves. We believe that our cash flows from operations, current cash and investments on hand, availability under our senior credit facility and the proceeds from this offering will be sufficient to meet our capital expenditure budget for the next twelve months.

Our capital expenditures by segment were:

	Year Ended December 31,			Six Months Ended June 30,	
	2004	2005	2006	2006	2007
			(In thousands)		
Capital Expenditures:					
Exploration and production	$ 29,105	$ 61,227	$ 170,872	$ 51,734	$ 377,120
Drilling and oil field services	22,679	43,730	89,810	49,123	83,913
Midstream gas services	2,026	25,904	16,975	8,019	23,130
Other	4,116	3,735	28,884	5,624	7,981
Total capital expenditures	$ 57,926	$ 134,596	$ 306,541	$ 114,500	$ 492,144

We estimate that our total capital expenditures for 2007 will be approximately $1,200 million, of which $492.1 million has been spent as of June 30, 2007. Our planned 2007 capital expenditures represents a 292% increase over 2006.

Our 2007 capital expenditures for our exploration and production segment are focused on growing and developing our reserves and production on our existing acreage and acquiring additional acreage, primarily in the WTO. Of our total $1,200 million capital expenditure budget, approximately $943 million is budgeted for exploration and production activities. We plan to drill 207 gross (177 net) wells in the WTO and 89 gross (79 net) wells in other areas in 2007. Included in our 2007 exploration and production capital expenditure budget is $167 million allocated to increasing our acreage positions in the WTO and the acquisition of seismic data, including proprietary 3-D seismic, which will be a valuable tool in helping us to explore and further develop the WTO.

During 2007 we expect to complete our rig fleet expansion program that we started in 2005. We have accepted the delivery of all of the rigs ordered from Chinese manufacturers. We are in the process of retro-fitting and rigging up five of these rigs, which we expect to join our fleet during the fourth quarter of 2007 through the second quarter of 2008. We are also continuing to upgrade and modernize our rig fleet. Approximately $115 million of our capital expenditure budget will be spent on our drilling and oil field services segment.

We anticipate spending approximately $103 million in capital expenditures in our midstream gas services segment as we aggressively expand our network of gas gathering lines and plant and compression capacity.

During the remainder of 2007, we expect to incur approximately $24 million in 2007 in additional capital expenditures related to PetroSource primarily for the continuance of our CO_2 flood operations at the Wellman Unit and the commencement of our CO_2 flood operations at the George Allen Unit. We capitalize a portion of the acquisition cost of CO_2 used in our CO_2 floods as development cost when it is injected.

We expect our 2008 capital expenditure program to be approximately $1,100 million, subject to market conditions and availability of capital on attractive terms, as we continue to explore and develop our core properties and expand our other business segments. We anticipate that approximately $957 million will be spent on exploration and production capital expenditures, $107 million on midstream services capital expenditures and $36 million on oil field services capital expenditures.

The majority of our capital expenditures will be discretionary and could be curtailed if our cash flows decline from expected levels or we are unable to obtain capital on attractive terms; however, we have various sources of capital in the form of our revolving credit facility, potential asset sales or the incurrence of additional long-term debt.

Cash Flows from Continuing Operations

Our cash flows from continuing operations are as follows:

	Year Ended December 31,			Six Months Ended June 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	$ 30,402	$ 180,844
Cash flows used in investing activities	(59,408)	(155,826)	(1,340,567)	(119,597)	(493,310)
Cash flows provided by financing activities	34,700	126,413	1,266,435	48,125	275,717
Net increase (decrease) in cash and cash equivalents	$ 13,750	$ 33,884	$ (6,783)	$ (41,070)	$ (36,749)

Operating Activities. Cash flows provided by operating activities increased $150.4 million to $180.8 million for the six months ended June 30, 2007 from $30.4 million for the six months ended June 30, 2006. The increase was caused by increased revenues of $134.3 million and lower cash payments for expenses during the six months ended June 30, 2007. We accelerated our collections of trade receivables resulting in lower accounts receivables in spite of significantly higher revenues. Trade accounts payables provided $56.2 million in operating cash flows as we actively managed our cash and debt balances at June 30, 2007.

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 $493.3 million in the six month period ended June 30, 2007 from $119.6 million in the 2006 period as we continued to ramp up our capital

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expenditure program. For the six month period ended June 30, 2007, our capital expenditures were $377.1 million in our exploration and production segment, $83.9 million for drilling and oil field services, $23.1 million for midstream gas services and $8.0 million for other capital expenditures. During the same period in 2006, capital expenditures were $51.7 million in our exploration and production segment, $49.1 million for drilling and oil field services, $8.0 million for midstream gas services and $5.6 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 $1,152.8 million for the six months ended June 30, 2007, and we repaid approximately $1,154.4 million leaving net repayments during the period of approximately $1.6 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 $275.7 million in cash for the six month period ended June 30, 2007 compared to $48.1 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

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subsidiaries ability to incur additional indebtedness with certain exceptions, including under the senior unsecured bridge facility (as discussed below).

The senior credit facility also contains financial covenants, including maintenance of agreed upon levels for the ratio of (i) 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 second 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 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 initially set at $300.0 million and was subsequently increased to $700.0 million. As of June 30, 2007 we had no outstanding indebtedness on our senior credit facility and as of October 12, 2007 we had $455 million outstanding under the senior credit facility, prior to the application of available cash balances.

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.

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

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loan includes both a fixed rate tranche and floating rate tranche. Approximately $650 million was issued at a fixed rate of 8.625% with principal due on April 1, 2015 (the Fixed Rate Term Loans). Under the terms of the Fixed Rate Term Loans, interest is payable quarterly and during the first four years interest may be paid, at 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 as follows (the prepayment penalty is multiplied by the principal amount prepaid):

Period	Prepayment Penalty
April 1, 2011 to March 31, 2012	4.313%
April 1, 2012 to March 31, 2013	2.156%
April 1, 2013 and thereafter	

Approximately $350 million of the term loan was issued at a variable rate with interest payable quarterly and principal due on April 1, 2014 (the Variable Rate Term Loans). The Variable Rate Term Loans bear interest, at 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 as follows (the prepayment penalty is multiplied by the principal amount prepaid):

Period	Prepayment Penalty
April 1, 2009 to March 31, 2010	3.00%
April 1, 2010 to March 31, 2011	2.00%
April 1, 2011 to March 31, 2012	1.00%
April 1, 2012 and thereafter	

After one year from the closing date, 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 the specified date, 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 ordinary and customary covenants 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 June 30, 2007, the aggregate outstanding balance of these credit agreements was $54.6 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 June 30, 2007 was $6.2 million.

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

As a portion of the consideration for an acquisition in October 2007, we entered into a note for $50.0 million. This note incurs interest at a rate of 7.00% per annum and matures on September 30, 2008. We intend to repay this note with a portion of the proceeds of this offering.

Senior Bridge Facility. On November 21, 2006, we also entered into a $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 (USA) LLC, Goldman Sachs Credit Partners L.P., and Lehman Brothers Inc., as joint lead arrangers and bookrunners.

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

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

Prior Senior Credit Facility. Prior to its termination on November 21, 2006, we had a $130 million revolving credit facility in place with Bank of America, N.A. (the prior senior credit facility). The prior senior credit facility included a $20 million sub-limit for letters of credit. The prior senior credit facility was replaced by the senior credit facility as of November 21, 2006. Advances under the prior senior credit facility were subject to a borrowing base based on our proved developed producing reserves, our proved developed non-producing reserves and proved undeveloped reserves. It is 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.

Convertible Preferred Stock

We have 2,184,287 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 June 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. Upon satisfaction of certain conditions set forth in the certificate of designations, we have the right to convert all of the outstanding shares of convertible preferred stock to common stock at any time after 180 days following the completion of the offering. In connection with this conversion, we may be required to make a cash payment to each holder of convertible preferred stock. Please see Description of Capital Stock Convertible Preferred Stock.

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Contractual Obligations

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

	Payments Due by Year (In thousands)						
	Remainder of 2007	2008	2009	2010	2011	After 2011	Total
Long-term debt	$ 14,158	$ 16,285	$ 17,330	$ 12,286	$ 6,597	$ 1,000,000	$ 1,066,656
Interest on term loan(1)	43,738	87,475	87,475	87,475	87,475	252,881	646,519
Firm transportation(2)	475	949	949	949	949	4,592	8,863
Operating leases	2,418	4,525	2,707	110	46	0	9,806
Third party drilling rig commitments(3)	10,077	8,325					18,402
Dispute settlement payments(4)		5,000	5,000	5,000	5,000		20,000
Asset retirement obligations	828	147		195	8,403	46,265	55,838
Total	$ 71,694	$ 122,706	$ 113,461	$ 106,015	$ 108,470	$ 1,303,738	$ 1,826,084

(1) Based on interest rates as of June 30, 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.

(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	$ 1,600
2008	3,200
2009	3,200
2010	5,000
Thereafter	4,000
	$ 17,000

Liquidated Damages Under Registration Rights Agreements

December 2005 Private Placement. In connection with our private placement of common stock in December 2005, we entered into a registration rights agreement that requires us to use our commercially reasonable efforts to register the shares of common stock sold in the private placement prior to April 15, 2007 and to maintain effectiveness after registration until December 21, 2007. In April 2007, we amended the registration rights agreement to require us to use our commercially reasonable efforts to register the shares of common stock no later than December 21, 2007 and to maintain effectiveness until December 21, 2009.

Generally, if we fail to have a registration statement declared effective by December 21, 2007 or fail to maintain an effective registration statement, we will be subject to liquidated damages payments equal to a one time payment of $1.2 million plus a percentage of the gross proceeds of the offering for each day we are not in compliance. The payments increase every 90 days, up to a maximum as specified in the registration rights agreement as follows:

Non-Compliance Period			
1-90 Days	**91-180 Days**	**181-270 Days**	**270+ Days**
$1.2 million plus 0.5% per annum ($3,300 per day)	1.0% per annum ($6,600 per day)	1.5% per annum ($9,900 per day)	2.0% per annum ($13,200 per day)

The liquidated damages for initial failure to have a registration statement declared effective by December 21, 2007 is retroactive to April 15, 2007. For purposes of calculating the liquidated damages for failure to have the initial registration statement declared effective by December 21, 2007 retroactive payment would be approximately $2.8 million, and December 21, 2007 would be considered the 250th day of non-compliance.

November 2006 Private Placement. In connection with our private placement of convertible preferred stock and common stock units, we entered into a registration rights agreement that requires us to use our commercially reasonable efforts to file a registration statement with respect to the shares of common stock underlying our convertible preferred stock prior to August 31, 2007 and use our commercially reasonable efforts to cause such registration statement to become effective prior to the earlier of (i) 181 days following the effectiveness of the registration statement related to our December 2005 private placement, or (ii) December 31, 2007. In general, if we fail to meet these deadlines or maintain effectiveness, we will be subject to liquidated damage payments equal to a percentage of the purchase price of the securities sold in the November 2006 private placement.

During the first nine months following any failure to meet the deadlines described above, the payments will be equal to a percentage of the purchase price of $550 million on a per month basis until the default is cured. During the first month following a default, the payment shall be equal to 0.25% of the purchase price and shall increase by 0.25% per month to a maximum of 0.75%. If the default has not been cured within eight months, the payments will become equal to 2.0% per annum paid on a monthly basis until such default is cured.

March 2007 Private Placement. In connection with our private placement of common stock in March 2007, we entered into a registration rights agreement that requires us to use commercially reasonable efforts to register the shares of common stock sold in the private placement prior to 90 days following the effectiveness of the registration statement related to our December 2005 private placement. Generally, if we fail to have a registration statement declared effective within 90 days of filing or fail to maintain an effective registration statement, we will be subject to liquidated damages payments equal to a one time payment of $1.6 million plus a percentage of the gross proceeds of the offering for each day that we are not in compliance. The payments increase every 90 days, up to a maximum as specified in the registration rights agreement as follows:

Non-Compliance Period			
1-90 Days	91-180 Days	181-270 Days	270+ Days
$1.6 million plus 0.5% per annum ($4,400 per day)	1.0% per annum ($8,800 per day)	1.5% per annum ($13,200 per day)	2.0% per annum ($17,600 per day)

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We have not reserved any funds related to liquidated damages and do not believe any amounts will be paid.

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

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effective for fiscal years beginning after November 15, 2007. We are currently evaluating the impact of adopting SFAS No. 157 on the financial statements.

Effects of Inflation

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

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

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

Quantitative and Qualitative Disclosures About Market Risk

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

Commodity Price Risk

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

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

For natural gas derivatives, transactions are settled based upon the New York Mercantile Exchange price of natural gas at the Henry hub, a 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 six months ended June 30, 2006 and 2007 was a gain of $10.6 million and $16.0 million, respectively.

At June 30, 2007, our open commodity derivative contracts consisted of the following:

Period	Commodity	Notional	Weighted Avg. Fix Price
Fixed price swap:			
April 2007 - September 2007	Natural gas	3,660,000 MmBtu	$ 7.87
April 2007 - September 2007	Natural gas	3,660,000 MmBtu	$ 8.05
April 2007 - October 2007	Natural gas	4,280,000 MmBtu	$ 7.02
April 2007 - October 2007	Natural gas	4,280,000 MmBtu	$ 7.50
May 2007 - September 2007	Natural gas	3,060,000 MmBtu	$ 7.75
May 2007 - September 2007	Natural gas	1,530,000 MmBtu	$ 8.16
June 2007 - August 2007	Natural gas	920,000 MmBtu	$ 8.18
June 2007 - August 2007	Natural gas	920,000 MmBtu	$ 8.30
July 2007 - September 2007	Natural gas	920,000 MmBtu	$ 8.25
September 2007 - December 2007	Natural gas	1,220,000 MmBtu	$ 8.88
October 2007 - December 2007	Natural gas	920,000 MmBtu	$ 8.77
October 2007 - December 2007	Natural gas	920,000 MmBtu	$ 9.04
October 2007 - December 2007	Natural gas	920,000 MmBtu	$ 8.00
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	$ 8.505
January 2008 - June 2008	Natural gas	3,640,000 MmBtu	$ 7.987
January 2008 - June 2008	Natural gas	3,640,000 MmBtu	$ 7.99
January 2008 - December 2008	Natural gas	3,660,000 MmBtu	$ 9.00
January 2008 - December 2008	Natural gas	3,660,000 MmBtu	$ 8.48
May 2008 - August 2008	Natural gas	2,460,000 MmBtu	$ 8.375
Collars:			
January 2007 - December 2007	Crude oil	60,000 Bbls	$ 50.00 - $84.50
January 2008 - June 2008	Crude oil	42,000 Bbls	$ 50.00 - $83.35
July 2008 - December 2008	Crude oil	54,000 Bbls	$ 50.00 - $82.60
Waha basis swap:			
January 2007 - December 2007	Natural gas	14,600,000 MmBtu	$ (0.70)
January 2007 - December 2007	Natural gas	7,300,000 MmBtu	$ (0.5925)
April 2007 - September 2007	Natural gas	3,660,000 MmBtu	$ (0.470)

April 2007 - October 2007	Natural gas	4,280,000 MmBtu	$	(0.530)
May 2007 - September 2007	Natural gas	3,060,000 MmBtu	$	(0.65)
January 2008 - December 2008	Natural gas	7,320,000 MmBtu	$	(0.585)
January 2008 - December 2008	Natural gas	7,320,000 MmBtu	$	(0.6525)

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Period	Commodity	Notional	Weighted Avg. Fix Price	
Waha basis swap (continued):				
January 2008 - December 2008	Natural gas	7,320,000 MmBtu	$	(0.635)
January 2008 - December 2008	Natural gas	7,320,000 MmBtu	$	(0.59)
January 2008 - December 2008	Natural gas	3,660,000 MmBtu	$	(0.625)
January 2008 - December 2008	Natural gas	10,980,000 MmBtu	$	(0.57)
January 2008 - December 2008	Natural gas	3,660,000 MmBtu	$	(0.595)
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)

Since June 30, 2007, we have entered into the following commodity derivative contracts:

Period	Commodity	Notional	Weighted Avg. Fix Price	
Fixed price swap:				
August 2007	Natural gas	(310,000) MmBtu	$	6.60
August 2007	Natural gas	(310,000) MmBtu	$	6.35
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	$	8.04
January 2008 December 2008	Natural gas	3,660,000 MmBtu	$	8.23
July 2008	Natural gas	310,000 MmBtu	$	8.02
July 2008 September 2008	Natural gas	920,000 MmBtu	$	8.23
July 2008 December 2008	Natural gas	1,840,000 MmBtu	$	8.31
August 2008	Natural gas	310,000 MmBtu	$	8.00
September 2008	Natural gas	300,000 MmBtu	$	8.05

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, 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 June 30, 2007, we had no outstanding borrowings under our senior credit facility. Based on the approximately $350.0 million outstanding balance of the variable rate portion of our term loan at June 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 $1.8 million for the six months ended June 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 June 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 growing 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 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 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.

Recent WTO Acquisition

We recently completed an acquisition of natural gas properties in the WTO consisting of approximately 6,660 net leasehold acres. We estimate that net proved reserves of approximately 39.4 Bcfe and net production of approximately 3.1 Mmcfe per day are attributable to this acreage. The purchase price of these assets was approximately $75 million, consisting of $25 million cash and a $50 million note to be repaid with the proceeds of this offering.

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.

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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 will own 38.4% of our capital stock on a fully-diluted basis following the completion of this offering, 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,

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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)(2)	Proved Reserves/ Production	Gross Acreage	Net Acreage	Number of Identified Potential Drilling Locations
Area							
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	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	98.5	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	19.0	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 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) 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.

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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 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 3Q 2007 End
431.1	675.2	406	2,658	207	$ 537	9	30

(1) As of June 30, 2007.

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

East Texas Cotton Valley Trend

We own significant natural gas and oil interests in the natural gas bearing Cotton Valley Trend in East Texas, which covers parts of East Texas and Northern Louisiana. We held interests in 48,606 gross (32,557 net) acres in East Texas as of June 30, 2007. At 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 are 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. 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 25.9 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	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.

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

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

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

Estimates of proved reserves do not include the following:

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

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

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

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

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

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Production and Price History

The following tables set forth information regarding our net production of oil, natural gas and natural gas liquids and certain price and cost information for each of the periods indicated. Because of the relatively high volumes of CO_2 produced with natural gas in certain areas of the WTO, our reported sales and reserves volumes and the related unit prices received for natural gas in these areas are reported net of CO_2 volumes stripped at the gas plants. The gas plant fees for removing CO_2 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 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,			Six Months Ended June 30,	
	2004	2005	2006	2006	2007
Production Data:					
Natural Gas (Mmcf)	6,708	6,873	13,410	4,219	22,292
Oil (MBbls)	37	72	322	46	906
Combined Equivalent Volumes (Mmcfe)	6,930	7,305	15,342	4,495	27,728
Average Daily Combined Equivalent Volumes (Mmcfe/d)	18.9	20.0	42.0	24.8	153.2

Our average daily combined equivalent volumes of production for the month of September 2007 was 191.2 Mmcfe per day.

	Year Ended December 31,			Six Months Ended June 30,	
	2004	2005	2006	2006	2007
Average Prices(1):					
Natural Gas (per Mcf)	$ 4.43	$ 6.54	$ 6.19	$ 6.08	$ 6.90
Oil (per Bbl)	$ 34.03	$ 48.19	$ 56.61	$ 62.99	$ 58.18
Combined Equivalent (per Mcfe)	$ 4.47	$ 6.63	$ 6.60	$ 6.35	$ 7.45

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

	Year Ended December 31,			Six Months Ended June 30,	
	2004	2005	2006	2006	2007
Expenses per Mcfe:					
Lease operating expenses:					
Transportation	$ 0.14	$ 0.16	$ 0.22	$ 0.22	$ 0.17
Processing and gathering(1)	0.39	0.42	0.37	0.53	0.25
Other lease operating expenses	0.94	1.64	1.70	2.29	1.34
Total lease operating expenses	$ 1.48	$ 2.22	$ 2.29	$ 3.04	$ 1.77

Production taxes	$ 0.36	$ 0.43	$ 0.30	$ 0.34	$ 0.29

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

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 West Texas.

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 26 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.

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 85 Mmcf per day of gas. A project to increase the plant capacity to 90 Mmcf per day will be completed during the fourth 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, 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.

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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 161 miles of CO_2 pipelines in West Texas with approximately 92,000 horsepower of owned and leased CO_2 compression available with approximately 54,000 horsepower currently operational. In addition, PetroSource has exclusive long-term supply contracts to gather CO_2 from natural gas treatment plants in West Texas and is the sole gatherer of CO_2 from the four natural gas treatment plants located in the Delaware and Val Verde Basins of West Texas. The primary use of our CO_2 supply is for use in our and third-parties tertiary oil recovery operations. We have assembled an experienced

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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 101 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 September 2007, we captured and sold 80 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.

We believe our supply of CO_2, focus on small to mid-sized acquisitions and technical expertise enable us to compete effectively in our tertiary oil recovery 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.

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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;

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- 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 2,200 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 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.

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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	43	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	60	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	51	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-

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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.

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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 expect to establish a compensation committee prior to the closing of this offering consisting of three directors, at least one of which will have been determined by the board of directors to be independent under the standards of the New York Stock Exchange. Our board of directors will determine the members of the compensation committee and the scope of the compensation committee s authority. We anticipate that the authority of the committee will include, 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.

In addition, we anticipate that the charter of our compensation committee will grant 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.

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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.

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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

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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 228,261 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.

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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.

(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.

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(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 Dues	Accounting Support	Aircraft Use(a)	Life Insurance Premiums	Company Matching Contributions to 401(k) Plan	Relocation Expenses or Bonus	Retention or Severance Payment	Employee Participation Plan Participation Allowance	Reimbursement of HSR Fees	T
t Officers:										
Ward	$ 2,926	$ 123,960	$ 122,598	$ 173					$ 125,000(b)	$ 3
Van Doren				$ 173	$ 7,788					$
y K. Grubb				$ 173		$ 8,771				$
Officers:										
ne , 3rd	$ 488		$ 16,827	$ 377		$ 120,000				$ 1
ines				$ 239			$ 37,500	$ 35,000		$
Pope				$ 226	$ 4,298	$ 30,200	$ 66,667	$ 35,000		$ 1
utton				$ 377	$ 10,125	$ 40,000		$ 42,000		$
y McCann				$ 377		$ 30,000	$ 500	$ 42,000		$

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

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

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Grants of Plan-Based Awards

The following table sets forth information about each grant of an award made to our named executive officers in 2006 under our stock plan pursuant to our restricted stock awards program, including awards, if any, that have been transferred.

Grants of Plan-Based Awards for the Year Ended December 31, 2006

Name	Grant Date	All Other Stock Awards: Number of Shares of Stock or Units
Current Officers:		
Tom L. Ward		
Dirk M. Van Doren	July 1, 2006	10,000
	September 29, 2006	25,000
Matthew K. Grubb	August 1, 2006	20,000
Former Officers:		
N. Malone Mitchell, 3rd		
John Gaines		
Barbara Pope		
Todd Dutton		
Matthew McCann		

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

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

Employment Agreements

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

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

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

Other Named Executive Officers. Prior to his resignation effective at the end of 2006, Mr. Mitchell was party to an employment agreement with terms identical to those of the employment agreement of Mr. Ward described above. This agreement was entered into in June 2006, simultaneously with the employment agreement with Mr. Ward and terminated upon his resignation. We have not entered into an employment agreement with any of our other named executive officers. However, we have entered into an employment agreement with another executive officer. See Employment Agreements Other Executive Officers. We intend to enter into additional employment agreements with other named executive officers in 2007.

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

Mr. Coshow s employment agreement also includes provisions governing the payment of severance benefits if his employment is terminated by us without cause or in connection with a Change of Control. The agreement also addresses termination due to death or disability.

Restricted Stock Awards Program

Prior to 2006, the board of directors granted several of our named executive officers restricted stock pursuant to our restricted stock awards program which vested on the fourth and seventh anniversaries of the date of the grant. Following the resignations of Mr. Gaines and Ms. Pope, the board of directors elected to accelerate the vesting of the restricted stock that had been granted to Mr. Gaines and Ms. Pope under the program. The board of directors also accelerated the vesting of 25% of Mr. Dutton s four-year restricted stock upon his resignation.

Following June 2006, our restricted stock award program has continued to be used to retain our named executive officers and better align their interests with those of our stockholders. In addition, the program is intended to enable us to effectively recruit highly qualified individuals by offering the potential for significant return following our initial public offering. Grants of restricted stock are made in the discretion of the board of directors. On July 1, 2006 and September 29, 2006, our board of directors approved grants of 10,000 shares of restricted stock and 25,000 shares of restricted stock, respectively, to Mr. Van Doren, 10,000 of which vest in 25% increments on each of the next four anniversaries of the date of the grant, 12,500 of which vest in 25% increments on January 1, 2008 and each of the next three anniversaries thereof, and 12,500 of which vest in 25% increments on July 1, 2008 and each of the next three anniversaries thereof. On August 1, 2006, the board of directors approved a grant of 20,000 shares of restricted stock to Mr. Grubb, 10,000 of which vest in 25% increments on January 1, 2008 and each of the next three anniversaries thereof and 10,000 of which vest in 25% increments on July 1, 2008 and each of the next three anniversaries thereof.

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Salary and Cash Bonus Awards in Proportion to Total Compensation

The following table sets forth the percentage of each named executive officer s total compensation that we paid in the form of base salary and annual cash bonus awards during 2006.

Name	Percentage of Total Compensation
Current Officers:	
Tom L. Ward	79.7%
Dirk M. Van Doren	85.6%
Matthew K. Grubb	91.1%
Former Officers:	
N. Malone Mitchell, 3rd	81.6%
John Gaines	5.6%
Barbara Pope	4.4%
Todd Dutton	34.4%
Matthew McCann	38.6%

Outstanding Equity Awards Value Fiscal Year-End

The following table reflects all outstanding equity awards held by our named executive officers as of December 31, 2006.

Outstanding Equity Awards as of December 31, 2006

	Stock Awards	
Name	Number of Shares or Units of Stock That Have Not Vested	Market Value of Shares or Units of Stock That Have Not Vested(1)
Current Officers:		
Tom L. Ward		
Dirk M. Van Doren	35,000(2)	$ 630,000
Matthew K. Grubb	20,000(3)	$ 360,000
Former Officers:		
N. Malone Mitchell, 3rd		
John Gaines		
Barbara Pope		
Todd Dutton		
Matthew McCann	100,000(4)	$ 1,800,000

(1) Valuation based on $18.00 per share.

(2) Includes (a) 10,000 shares that vest in 25% increments on each of the next four anniversaries of the date of the grant (July 1, 2006), (b) 12,500 shares that vest in 25% increments on January 10, 2008 and each of the next three anniversaries thereof, and (c) 12,500 shares that vest in 25% increments on July 2, 2008 and each of the next three anniversaries thereof.

(3) Includes (a) 10,000 shares that vest in 25% increments on January 10, 2008 and each of the next three anniversaries thereof, and (b) 10,000 shares that vest in 25% increments on July 1, 2008 and each of the next three anniversaries thereof.

(4) Includes (a) 66,667 shares that began to vest in 25% increments beginning on January 1, 2007 and will continue to vest on each of the next three anniversaries thereof, and (b) 33,333 shares that vest June 30, 2013. Mr. McCann forfeited all unvested shares upon his resignation effective June 30, 2007.

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Option Exercises and Stock Vested

The following table reflects the restricted stock of our named executive officers that vested during 2006. No stock options were outstanding in 2006.

Option Exercises and Stock Vested for the Year Ended December 31, 2006

	Stock Awards	
Name	**Number of Shares Acquired on Vesting**	**Value Realized on Vesting**
Current Officers:		
Tom L. Ward		
Dirk M. Van Doren		
Matthew K. Grubb		
Former Officers:		
N. Malone Mitchell, 3rd		
John Gaines	83,333	$ 1,437,494
Barbara Pope	111,000	$ 2,109,000
Todd Dutton	26,667	$ 490,006
Matthew McCann	10,000	$ 190,000

Potential Payments Upon Termination or Change in Control

Severance Under Employment Agreement of Tom L. Ward

Termination Other Than For Cause. In the event we terminate Mr. Ward s employment other than for Cause (as defined below), Mr. Ward is entitled to receive (1) his base salary as in effect on the date of termination during the remaining term of the employment agreement or through the expiration date of the agreement and (2) any vacation pay accrued through the date of termination. If Mr. Ward was terminated other than for Cause on December 31, 2006, his severance would equal $2,250,000 (base salary for 30 months, which is the remaining term of his employment agreement), and the maximum value of his accrued vacation (assuming he took no time off during the year) would be $86,538.

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

Termination in Connection with Change in Control. In the event that Mr. Ward s employment is terminated within one year of a Change in Control event (as defined below) other than for Cause, death or disability, Mr. Ward is entitled to receive (1) a single, lump sum severance payment within 10 days of termination equal to 3 times his base salary for the last 12 calendar months and bonus paid (based on an average of the last three years annual bonuses or such lesser number of years as he was employed) and (2) any applicable gross-up payment (as defined below). To the extent that any payment or distribution is subject to excise tax under Section 4999 of the Code or any other interest of penalties related to such excise tax (collectively Excise Tax), the agreement provides we will pay an additional amount (the Gross-Up Payment) such that after payment by Mr. Ward of all taxes on the Gross-Up Payment, he will retain an amount of the Gross-Up Payment equal to the Excise Tax. If Mr. Ward were terminated within one year of a

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Change in Control event other than for Cause, death or disability, his severance would equal $5,500,000 (3 times the sum of his base salary in 2006 of $900,000 plus his bonus of $950,000) plus a Gross-Up Payment equal to $2,508,535 for a total payment of $8,058,535.

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

In addition, notwithstanding any provision to the contrary in any option agreement, restricted stock agreement, plan or other agreement relating to equity based compensation, in the event of a termination without Cause or in connection with a Change in Control, all Mr. Ward s units, stock options, incentive stock options, performance shares, stock appreciation rights and restricted stock (collectively awards) will immediately become 100% vested. Further, Mr. Ward s right to exercise any previously unexercised options will not terminate until the latest date on which such option would expire but for Mr. Ward s termination. To the extent, we are unable to provide for one or both of the foregoing rights, we will provide in lieu thereof a lump-sum cash payment equal to the difference between the total value of such awards with the foregoing rights and the total value without the foregoing rights. Mr. Ward currently has no unvested compensatory equity awards.

Termination for Cause. In the event Mr. Ward is terminated for Cause, we will have no further obligation to provide further payments or benefits. If Mr. Ward desires to voluntarily terminate, he must give 90 days notice of his intent to termination during which time he can use accrued vacation time or be paid for such days. If Mr. Ward was terminated for Cause on December 31, 2006, the maximum value of his accrued vacation time (assuming he took no time off during the year) would be $86,538.

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

Termination due to Disability. If Mr. Ward s employment is terminated due to disability, then he is entitled to receive base salary through the remaining term of his employment agreement or through the Expiration Date of the agreement. If Mr. Ward was terminated due to disability on December 31, 2006, his severance would equal $2,250,000 (base salary for 30 months, which is the remaining term of his employment agreement).

Termination due to Death. In the event Mr. Ward s employment terminates due to death, then he will be entitled to receive (1) base salary payment for 12 months after termination and (2) any accrued benefits. If Mr. Ward was terminated due to death on December 31, 2006, his severance would equal $900,000 (12 months salary) plus the maximum value of his accrued vacation (assuming he took no time off during the year) equal to $86,538.

Stock Plan

Upon disability (as defined below) or death of any named executive officer, any benefits awarded under the 2005 Stock Plan will become vested to the extent that vesting would have occurred had the named executive officer remained a participant for a period of 12 months after termination. Disability is defined as the inability to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment which can be expected to result in death or which has lasted or can be expected to last for a continuous period of 12 months. An option or stock appreciation right that is vested pursuant to disability must be exercised within 18 months or such shorter time as specified in the grant from the date on which termination occurred or the option or stock appreciation right will terminate. If a named executive officer dies who was no longer a participant at the time of death and his options or stock appreciation rights have not yet expired, those options or stock appreciation rights may be exercised within 12 months following death. Mr. Van Doren holds two separate grants of 10,000 and 25,000 shares of restricted stock respectively; only 2,500 shares of the grant of 10,000 shares of restricted stock would vest within the 12 months following his death or disability on December 31, 2006. (See Outstanding Equity Awards Fiscal Year-End for vesting schedule). The value of the shares of restricted stock vesting upon the death or disability of Mr. Van Doren on December 31, 2006 is $45,000 ($18 per share times 2,500 shares). Mr. Grubb holds 20,000 shares of restricted stock; none of his shares would vest within 12 months of his death or disability occurring on December 31, 2006. (See Outstanding Equity Awards Fiscal Year-End for vesting schedule).

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

Description of Stock Plan

Scope

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

The Plan authorizes 7,074,252 shares of common stock to be used for awards. As of June 30, 2007, approximately 1.6 million shares had been awarded as restricted stock subject to vesting periods of one, four and seven years (other than shares cancelled or forfeited), and 5.6 million shares, representing 4.2% of the outstanding shares of common stock after this offering, are available to be used for future awards. If an award

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made under the Plan expires, terminates or is forfeited, canceled, settled in cash without issuance of shares of common stock covered by the award, or if award shares are used to pay for other award shares, those shares will be available for future awards under the Plan. We have not made any awards under the Plan to date.

Eligibility

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

Stock Options

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

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

Stock Appreciation Rights

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

Restricted Stock

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

Other Stock Based Awards

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

Dollar-Denominated Awards

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

Adjustments

In the event of any changes in the outstanding shares of common stock by reason of any stock dividend, split, spinoff, recapitalization, merger, consolidation, combination, exchange of shares or other similar change, the aggregate number of shares with respect to which awards may be made under the Plan, and the terms and the number of shares of any outstanding option, restricted stock or other stock-based award, may be equitably adjusted by the compensation committee in its sole discretion.

Change of Control

Upon a change in control, which is defined in the Plan to include certain third-party acquisitions of 50% or more of our then outstanding common stock or the combined voting power of the then outstanding common stock entitled to vote generally in the election of directors, changes in the composition of the board of directors, stockholder approval of certain significant corporate transactions such as a reorganization, merger, consolidation, sale of assets or the liquidation or dissolution of the company, the board of directors may take any action with respect to outstanding Awards under the Plan as it deems appropriate, which action may vary among Awards granted to individual participants.

Administration

The Plan is administered by the board of directors or, if directed by the board of directors, the compensation committee of the board of directors or another committee designated by the board of directors (in each event, the compensation committee). The compensation committee makes determinations with respect to the participation of employees, directors and consultants in the Plan and, except as otherwise required by law or the Plan, the grant terms of awards, including vesting schedules, retirement and termination rights, payment alternatives such as cash, stock, contingent award or other means of payment consistent with the purposes of the Plan, and such other terms and conditions as the board or the compensation committee deems appropriate. The compensation committee has the authority at any time to provide for the conditions and circumstances under which awards shall be forfeited. The compensation committee has the authority to accelerate the vesting of any award and the time at which any award becomes exercisable.

Termination and Amendment

The board may at any time terminate the Plan or from time to time make such modifications or amendments of the Plan as it may deem advisable; provided, however, that the board shall not make any amendments to the Plan which require stockholder approval under applicable law, rule or regulation unless approved by the requisite vote of our stockholders. No termination, modification or amendment of the Plan may adversely affect the rights conferred by an award without the consent of the recipient thereof.

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PRINCIPAL STOCKHOLDERS

The following table sets forth certain information with respect to the beneficial ownership of our common stock as of September 30, 2007 and as adjusted to give effect to this offering by:

- each stockholder known by us to be the beneficial owner of more than 5% of the outstanding shares of our common stock;
- our current directors;
- our named executive officers; and
- all of our directors and executive officers as a group.

Unless otherwise indicated in the footnotes to this table and subject to community property laws where applicable, we believe that each of the stockholders named in this table has sole voting and investment power with respect to the shares indicated as beneficially owned.

	Number of Shares Beneficially Owned	Percentage of Shares Beneficially Owned	
		Prior to Offering	After Offering
Tom L. Ward	31,457,707(1)	28.0%	25.3%(2)
Dirk M. Van Doren	169,009	*	*
Matthew K. Grubb			
Bill Gilliland	1,348,489(3)	1.2%	*
Dan Jordan	766,666	*	*
Roy T. Oliver, Jr.	850,000(4)	*	*
D. Dwight Scott	(5)		
Jeffrey Serota	(6)		
Entities affiliated with Ares Management LLC	13,333,333(7)	12.2%	9.6%
Entities affiliated with Farallon Partners, L.L.C.	6,985,068(8)	6.3%	5.0%
N. Malone Mitchell, 3rd	17,280,214(9)	15.7	12.5%
All directors and named executive officers as a group	34,591,362(1)	30.8%	27.5%(2)

* Less than 1%.

(1) Includes (a) 5,076,624 shares of common stock and 2,680,677 shares of common stock issuable upon conversion of convertible preferred stock held by TLW Properties, L.L.C. for which Mr. Ward exercises voting and dispositive power, (b) 79,000 shares held through an IRA and (c) 13,000 shares of common stock held by Mr. Ward s minor child. Does not include 6,509,601 shares held through a family trust.

(2) Includes 4,170,000 shares offered directly to TLW Properties, L.L.C., an entity controlled by Mr. Ward.

(3) Such shares are held by Gillco Energy, LP, for which Mr. Gilliland exercises voting and dispositive power.

(4) Such shares are held by Oliver Active Investments, LLC, for which Mr. Oliver exercises voting and dispositive power.

(5) Mr. Scott serves as a managing director of GSO Capital Partners LP, the investment manager for each of GSO Credit Opportunities Fund (Helios), L.P. (GSO Helios), GSO Special Situations Overseas Master Fund Ltd. (GSO Overseas) and GSO Special Situations Fund LP (GSO SS and, together with GSO Helios and GSO Overseas, the GSO Funds). Each of GSO Helios (286,354 shares), GSO Overseas (405,262 shares) and GSO SS (419,495 shares) are the holders of record of our common stock. As investment manager of the GSO Funds, GSO Capital Partners LP is vested with investment discretion with respect to investments held by the GSO Funds. GSO LLC (GSO General Partner) is the general partner of GSO Capital Partners LP, and in that capacity, directs the operations of GSO Capital Partners LP.

Bennett J. Goodman (Mr. Goodman), J. Albert Smith III (Mr. Smith) and Douglas I. Ostrover (Mr. Ostrover and together with Mr. Goodman and Mr. Smith, the GSO Managing Members) are the managing members of the General Partner, and in that capacity, direct the General Partner s operations. Each of the GSO Funds, GSO Capital Partners LP, General Partner and the Managing Members (collectively, the GSO Persons) may be deemed a beneficial owners of our common stock. However, the foregoing should not be deemed to constitute an admission that any of the GSO Persons are the beneficial owners of any of common stock owned by the GSO Funds. Mr. Scott disclaims any beneficial ownership of the shares of our common stock owned by the GSO Funds.

(6) Mr. Serota is a senior partner in the Private Equity Group of Ares Management LLC (Ares Management), a private investment management firm that indirectly controls Ares Corporate Opportunities Fund II, L.P. (ACOF II), Ares SandRidge, L.P. (Ares SandRidge), Ares SandRidge 892 Investors, L.P. (Ares 892 Investors) and Ares SandRidge Co-Invest, LLC (together with Ares SandRidge and Ares 892 Investors, the ACOF II AIVs). Mr. Serota disclaims beneficial ownership of the shares owned by ACOF II and the ACOF II AIVs, except to the extent of any pecuniary interest therein.

(7) The shares of common stock listed in the table above are owned as follows: ACOF II 7,376,636 shares; Ares SandRidge 1,996,851 shares; Ares 892 Investors 3,126,513 shares; and Ares SandRidge Co-Invest, LLC 833,333 shares. The general partner of ACOF II and certain of the ACOF II AIVs is ACOF Management II, L.P. (ACOF Management II) and the general partner of ACOF Management II is ACOF Operating Manager II, L.P. (ACOF Operating Manager II). ACOF Operating Manager II is indirectly controlled by Ares Management, which, in turn, is indirectly controlled by Ares Partners Management Company LLC. Each of the foregoing entities (collectively, the Ares Entities) and the partners, members and managers thereof, other than ACOF II and the ACOF II AIVs, disclaims beneficial ownership of the shares of common stock owned by ACOF II and the ACOF II AIVs, except to the extent of any pecuniary interest therein. The address of each Ares Entity is 1999 Avenue of the Stars, Suite 1900, Los Angeles, CA 90067.

(8) The shares of common stock listed in the table above are owned as follows: Farallon Capital Partners, L.P. 4,516,005 shares, 626,896 of which are issuable upon conversion of convertible preferred stock; Farallon Capital Institutional Partners, L.P. 1,921,924 shares, 499,907 of which are issuable upon conversion of convertible preferred stock; Farallon Capital Institutional Partners II, L.P. 268,911 shares, 39,671 of which are issuable upon conversion of convertible preferred stock; Farallon Institutional Partners III, L.P. 139,114 shares, 23,792 of which are issuable upon conversion of convertible preferred stock; and Tinicum Partners, L.P. 139,114 shares, 23,792 of which are issuable upon conversion of convertible preferred stock. As the general partner of each of these partnerships (such partnerships being the Farallon Partnerships), Farallon Partners, L.L.C. (FPLLC), may, for purposes of Rule 13d-3 under the Exchange Act, be deemed to beneficially own the shares beneficially owned by the Farallon Partnerships. As managing members of FPLLC, each of William F. Duhamel, Richard B. Fried, Monica R. Landry, Douglas M. MacMahon, William F. Mellin, Stephen L. Millham, Jason E. Moment, Ashish H. Pant, Rajiv A. Patel, Derek C. Schrier, Andrew J.M. Spokes, Thomas F. Steyer and Mark C. Wehrly (together, the Farallon Managing Members) may, for purposes of Rule 13d-3 under the Exchange Act, be deemed to beneficially own the shares beneficially owned by the Farallon Partnerships. Each of FPLLC and the Farallon Managing Members disclaim any beneficial ownership of such shares. All of the above-mentioned entities and persons disclaim group attribution.

(9) Includes (a) 485,630 shares issuable upon conversion of convertible preferred stock and 4,548 shares of common stock held by Dalea Partners for which Mr. Mitchell exercises voting and dispositive power and (b) 5,000 shares held by Mr. Mitchell s minor child. The address for Mr. Mitchell is 4801 Gaillardia Parkway, Suite 225, Oklahoma City, Oklahoma 73142.

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RELATED PARTY TRANSACTIONS

The following is a discussion of transactions between us and our officers, directors and beneficial owners of more than 5% of our common stock. During the fourth quarter of 2007, we adopted a written policy requiring any related party transaction (as defined below) to be reviewed and approved by the disinterested members of our board of directors. A related party transaction is a transaction, proposed transaction, or series of similar transactions, in which (a) we are a participant, (b) the amount involved exceeds $120,000 and (c) a related person (as defined below) has or will have a direct or indirect material interest. A related person is (i) any person who is, or at any time since the beginning of our last fiscal year was, a director, executive officer, or nominee to become a director, (ii) a person known to be the 5% beneficial owner of any class of our voting securities, (iii) an immediate family member of any of the foregoing persons, which means any child, stepchild, parent, stepparent, spouse, sibling, mother-in-law, father-in-law, son-in-law, daughter-in-law, brother-in-law, or sister-in-law of such director, executive officer, nominee for director or more than 5% beneficial owner, and (iv) any person (other than a tenant or employee) sharing the household of such director, executive officer, nominee for director or more than 5% beneficial owner. The written policy includes factors for disinterested board members to consider in exercising their judgment including terms of the transaction with the related party, availability of comparable products or services from unrelated third parties, terms available from unrelated third parties and the benefits to us.

Well Participation Plan

On June 8, 2006, we adopted the Well Participation Program (the WPP) which permitted Messrs. Ward and Mitchell to participate as working interest owners in the wells that we drill in the future. The WPP was adopted at a time when Mr. Ward proposed to become a significant stockholder of the Company. Our board of directors view was that drilling participation by senior management with significant ownership in us was in our best interest. The payment of proportionate costs of drilling of these wells is similar to a heads up drilling participation that we may, from time to time, enter into with unaffiliated industry participants on specific wells. Mr. Mitchell ceased to participate in the WPP upon his resignation, effective December 31, 2006. On September 21, 2007, Mr. Mitchell agreed to sell to us all of his interests under WPP. Please see Other Transactions with N. Malone Mitchell, 3rd. Mr. Ward remains a participant in the WPP.

Under the WPP, Mr. Ward is permitted to participate in all of the Program Wells, as defined in the WPP, spudded by or on behalf of SandRidge during each calendar year. In order to participate, at least 30 days prior to the beginning of each year, Mr. Ward must provide written notice to the members of the board of directors of his election to participate in the WPP and the percentage working interest which the participant proposes to participate with during the year. Mr. Ward s working interest percentage may not exceed a 3.0% working interest. Mr. Mitchell participated for a 2.0% working interest from June 8, 2006 through December 31, 2006, his effective date of resignation as an officer of SandRidge. Mr. Ward does not participate in any well where our working interest after Mr. Ward s participation would be reduced to below 12.5%. If Mr. Ward fails to provide notice of his election to participate or of the working interest percentage, the amount of the working interest percentage for the relevant calendar year will be deemed to be equal to the working interest percentage for the immediately preceding calendar year. Mr. Ward has participated for a 3.0% working interest in 2006 and elected to a 3.0% working interest for 2007.

The WPP is administered and interpreted by a committee of the board of directors consisting of Messrs. Gilliland and Jordan. Once a compensation committee is established, it will administer and interpret the WPP. In addition, the board of directors, in its sole discretion, may take any action with respect to the WPP that would otherwise be the responsibility of or delegated to the compensation committee. The board of directors has the right to suspend or terminate the WPP after December 31, 2015 by providing written notice of termination to Mr. Ward one year before the effective date of such termination. Mr. Ward s right to participate in the WPP during any calendar year will terminate on the earlier of (1) December 31 of such year; (2) the termination of Mr. Ward s employment by us for cause or death; or (3) the expiration or termination of any and all covenants not to compete subsequent to the termination of Mr. Ward for any reason not included in the foregoing clause (2).

Mr. Ward s working interest percentage cannot be changed during any calendar year without the prior approval of the compensation committee. Participation by Mr. Ward under the WPP is conditioned on his participation in each Program Well spudded during the calendar year in an amount equal to the greater of the elected working interest percentage or his prior interest in the drilling unit for such Program Well.

The amount paid by Mr. Ward for the acreage assigned in connection with his participation in the WPP is computed as of the first day of each calendar year and is equal to the following amount computed on a per acre basis: (1) all direct third-party costs paid by the Company Entities (as defined in the WPP) and capitalized in the appropriate accounting pool in accordance with our accounting procedures (including capitalized interest, leasehold payments, acquisition costs, landman charges and seismic charges); divided by (2) the acreage in the applicable pool. The acreage charge amount is recomputed by us as of the first day of each calendar year and submitted to the compensation committee for approval. All other costs for Program Wells are billed in accordance with our accounting procedures applicable to third-party participants pursuant to any applicable joint operating agreement or exploration agreement relating to a particular Program Well. Notwithstanding anything to the contrary, in each case the participant s participation in a Program Well will be on no better terms than the terms agreed to by unaffiliated third-party participants in connection with the participation in such Program Well or similar wells operated by the Company Entities.

Since the inception of the Well Participation Program in 2006, Messrs. Ward and Mitchell have participated in the drilling of 209 and 127 Program Wells, respectively. During 2006, Messrs. Ward and Mitchell were invoiced $1,951,904 and $1,592,136, respectively, for their share of costs for their interests in Program Wells, and received oil and gas revenues from their interests in Program Wells totaling $17,560 and $11,707 respectively. During the first six months of 2007, Messrs. Ward and Mitchell were invoiced $8,024,948 and $2,436,192, respectively, for their share of costs for their interests Program Wells, and received oil and gas revenues from all of their interests in all Program Wells, including Program Wells drilled in 2006, totaling $945,701 and $530,232, respectively. Mr. Mitchell has agreed to sell to us all of his interests under the WPP. Please see Other Transactions with N. Malone Mitchell, 3rd.

Employee Participation Plan

We adopted an Employee Participation Plan in December 2005 that allowed certain employees to participate in the drilling of natural gas and oil wells of our company for up to 5% of our interest in the well. Before that date, a similar plan was informally administered. Our board of directors view was that drilling participation by these key employees was in our best interest. We provided certain employees, including our named executive officers, an allowance to participate in these wells. These allowances were funded by us and treated as compensation. Participating employees were all entitled to invest amounts in addition to the Company funded allocations under the plan. The purpose of the plan was to associate the interest of our employees with the stockholders, maintain competitive compensation levels and provide an incentive for employees to continue employment with us. The plan was terminated effective for all wells drilled on or after May 1, 2006. From January 1, 2006 through the termination of the plan, we awarded $707,000 in allowances under the plan, including $35,000 for each of Mr. Gaines and Ms. Pope and $42,000 for each of Mr. Dutton and Mr. McCann. These allowances were treated as coupons from the Company. Following the termination of the plan, all interests in the plan were assigned to the applicable participant and no further payments were made pursuant to the plan.

No current executive officers of the Company participated in the Employee Participation Plan. During 2006, the following former executive officers were invoiced or assessed compensatory allowances for costs for their interests in the plan wells: Ms. Pope $98,399; Mr. Dutton $83,184; Mr. Gaines $46,902; Mr. McCann $338,635; and each of these former executive officers received oil and gas revenues from their interests in all plan wells, including interests in plan wells drilled in prior years, in the following amounts: Ms. Pope - $65,439; Mr. Dutton $18,491; Mr. Gaines $9,746; Mr. McCann $250,178.

During the first six months of 2007, the following former executive officers were invoiced for costs for their interests in the plan wells: Ms. Pope $11,485; Mr. Dutton $5,351; Mr. Gaines $3,287; Mr. McCann $43,879; and each of these former executive officers received oil and gas revenues from their interests in plan wells, including interests in wells drilled in prior years, in the following amounts: Ms. Pope $30,826; Mr. Dutton $10,378; Mr. Gaines $6,539; Mr. McCann $152,640. Following their departure from the Company in 2007, the Company purchased the interests in all plan wells from three of the former executive officers in negotiated acquisitions for the following cash payments: Ms. Pope $201,581; Mr. Dutton $75,394; Mr. Gaines - $53,534.

December 2005 Transactions

In December 2005, we entered into the following transactions with related parties as part of an effort to consolidate various interests in energy assets held by management, directors and independent third parties:

- the acquisition of interests in our Piceance Basin acreage, West Texas undeveloped acreage and Larco from Mr. Jordan, a director and our former Vice President, Business, for 1,418,182 shares of common stock valued at $15 per share;

- the acquisition of interests in PetroSource, our Piceance Basin acreage and our Missouri and Nevada projects from Gillco Energy, L.P., an entity controlled by Mr. Gilliland, a director, for 1,406,000 shares of common stock valued at $15 per share; and

- the acquisition of an interest in PetroSource from Mr. McCann, our former Senior Vice President Legal, for $135,000.

The disinterested members of our board of directors reviewed and approved the terms of the transactions with Messrs. Jordan, Gilliland and McCann. Simultaneously with the consummation of these transactions, we purchased other interests in the same assets from independent third parties on substantially similar terms and at substantially similar prices.

Private Placements

Affiliates of Mr. Ward and Mr. Mitchell purchased securities in our November 2006 and March 2007 private placements. Affiliates of Mr. Ward purchased 262,857 shares of our convertible preferred stock in our November 2006 private placement for $210 per share and 3,409,957 shares of common stock in our March 2007 private placement for $18 per share. Affiliates of Mr. Mitchell purchased 47,619 shares of our convertible preferred stock in our November 2006 private placement for $210 per share and 4,548 shares of common stock in connection with a preemptive right in our March 2007 private placement for $18 per share. These purchases were on identical terms and at identical prices as purchases made by independent third parties.

Other Transactions With N. Malone Mitchell, 3rd

Mr. Mitchell, our former Chairman, Chief Executive Officer and President, and his family, on September 30, 2005, traded 2.5% of our then outstanding common stock to us for our 100% interest in Longfellow Ranch Partners, LP (Longfellow). The purpose of this transaction was to separate the Longfellow ranch operations from our ongoing energy operations. While this transaction was approved by our board of directors and a majority of our stockholders, none of our directors at that time were disinterested and Mr. Mitchell controlled a majority of our outstanding common stock. Because of the unique nature of the transaction and the fact that none of our current officers or directors were officers or directors of the company at that time, we are unable to determine whether this transaction was on terms similar to those obtainable from third parties.

Longfellow owns surface or minerals or royalty under a significant amount of our exploration and development lands in West Texas, including the WTO. We have natural gas and oil leaseholds that cover all of Longfellow s minerals.

Under the leases, we will pay Longfellow royalties, based on production. The lease is for a seven-year primary term, with the option of extending the primary term another three years by paying a market value bonus. The lease royalty is 20% for wells completed before 2009, escalating to maximum of 25% in 2012. At the end of the primary term, the lease will break into approximately 3,000-acre tracts, and each tract will be subject to a 120-day continuous development clause. We also are party to a surface use agreement with Longfellow for use of the surface of the Longfellow Ranch. Under this agreement, we pay Longfellow fees, pursuant to a set schedule, for use of the surface for our natural gas and oil operations and for damages and rights of way. We believe the rates are equivalent to, or less than, the rates paid to other landowners in the area. As described below, this agreement was amended and restated on September 21, 2007. For 2003, 2004 and the nine months ended September 30, 2005, when operations were discontinued income (loss) from Longfellow s operations were ($128,000), $683,000 and $638,000, respectively. These numbers included, among other things, royalties, damages and agricultural operations on the lands, minerals and royalties now indirectly owned by the Mitchell family. For the last three months of 2005, the year ended 2006, and the six months ended June 30, 2007, we paid Longfellow $1,019,710, $4,156,082 and $1,458,958, respectively.

On September 21, 2007, we entered into a letter agreement with Mr. Mitchell, Longfellow and certain of his affiliates, pursuant to which we agreed to purchase certain natural gas and oil interests from Mr. Mitchell for a purchase price of $32 million. These natural gas and oil interests include the interests located on the West Ranch, a ranch adjacent to Longfellow Ranch. Mr. Mitchell recently entered into an agreement to purchase the West Ranch. The natural gas and oil interests also include all other interests of Mr. Mitchell and his affiliates in wells and leasehold acreage owned or operated by us or our affiliates, including interests owned through our Well Participation Program. For the years 2004, 2005, 2006 and the six months ended June 30, 2007, we paid Mr. Mitchell $147,000, $170,963, $140,538 and $18,183, respectively, in connection with his ownership interest in these assets.

The transactions contemplated by the letter agreement are subject to a number of closing conditions, including Mr. Mitchell s purchase of the West Ranch. We expect the acquisition to close within 20 days of the completion of this offering. In connection with the letter agreement, we also entered in to an amended and restated surface use and rights agreement regarding our access and use of the surface of lands owned by Mr. Mitchell in connection with our natural gas and oil interests on such lands.

The disinterested members of our board of directors determined that the transactions contemplated by the letter agreement, including the amended and restated surface use agreement, are on terms not materially less favorable than those that might reasonably have been obtained in a comparable transaction on an arms-length basis from a party that is not our affiliate and are fair to us from a financial point of view. Simultaneously with the execution of the letter agreement, Mr. Mitchell resigned as a director.

In August 2006, Mr. Mitchell acquired our interest in entities which owned Stockton Plaza, a commercial shopping center located in Fort Stockton, Texas, a restaurant franchise, and other non-core assets and investments, for an aggregate purchase price of $6,128,899. This transaction was determined to be in our best interests by the disinterested members of our board of directors and we believe it to be on terms similar to those available from unaffiliated third parties.

On May 2, 2007, we acquired oil and gas leaseholds on mineral interests held by the State of Texas underlying surface properties owned by Longfellow. Under Texas law, Longfellow executed these leases as agent for the State of Texas and is entitled to receive one-half of the payments made to the lessor under the leases. As a result, we paid Longfellow $8.3 million for its share of lease bonus payments. The terms of these lease transactions were similar to other State of Texas lease transactions that we negotiated in the ordinary course of our business with third party surface owners for nearby leaseholds. Our senior officers negotiated the terms of the lease transactions at arms length with Mr. Mitchell, acting as an officer of Longfellow in its capacity as agent for the State of Texas, and the transactions were approved by the disinterested members of our board of directors.

Other Transactions With Dan Jordan

Mr. Jordan, a director and our former Vice President, Business, has participated in projects since 2000. In March 2006, we acquired Mr. Jordan s 12.5% interest in PetroSource for $5,489,401. In July 2006 we acquired Mr. Jordan s interests in our producing natural gas and oil properties for $9,000,000. For the years 2004, 2005, 2006 and the six months ended June 30, 2007, we recognized the capital contributions from Mr. Jordan related to our drilling projects of $4,274,000, $5,670,081, $2,397,188 and $324,950, respectively. For the same periods, we paid Mr. Jordan $1,532,000, $2,113,020, $1,496,598 and $6,156, respectively. From August 2002 until October 2005, he received consulting fees from Larco of $40,000 per month. In June 2007, we purchased

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all of the interests in twelve producing wells and one well being drilled, which interests were owned by Wallace Jordan, LLC, a limited liability company a majority interest in is owned and controlled by Mr. Jordan (Wallace Jordan). In addition and as a part of this same transaction, we purchased the interest owned by Wallace Jordan in the Sabino pipeline and the West Piñon Gathering System and certain oil and gas leases covering lands in Pecos County, Texas, as well as the interest owned by Mr. Jordan individually in Integra Energy. The purchase price for these assets was $3.3 million plus the reimbursement of approximately $236,000 of costs attributable to Wallace Jordan s 10% working interest in one of our wells. Each of the transactions with Mr. Jordan was determined to be in our best interests by the disinterested members of our board of directors. We believe the terms of these transactions were similar to those that could have been obtained from an unrelated third party.

Other Transactions With Bill Gilliland

Mr. Gilliland has served as a director since January 2006. In 2003, Mr. Gilliland assisted us in the acquisition of the PetroSource assets and acquired an approximate 18.8% interest in PetroSource through Gillco Energy, L.P. Through that same entity, he also participated in our Piceance Basin acreage, and various drilling projects in Missouri and Nevada. As described above under December 2005 Transactions, we acquired these interests in December 2005. In February 2006, we acquired an office building in Midland, Texas from a partnership affiliated with Mr. Gilliland for $950,000. This transaction was determined to be in our best interests by the disinterested members of our board of directors. We believe the terms of this transaction were similar to those that could have been obtained from an unrelated third party.

Transaction With Roy Oliver

In September 2006, we entered into a new facilities lease with a director, Mr. Oliver. The lease extends to August 2009 with annual future rental payments of $1.1 million in 2007 and 2008 and $0.7 million in 2009. The terms of the lease were received and approved by our board of directors and we believe that the rent expense it must pay under this lease is at fair market rates. Rent expense in 2006 related to this facilities lease was $0.3 million.

DESCRIPTION OF CAPITAL STOCK

Our authorized capital stock consists of 400,000,000 shares of common stock, par value $0.001 per share, and 50,000,000 shares of preferred stock, no par value. Immediately prior to the consummation of this offering, we will have 109,471,022 outstanding shares of common stock and 2,184,287 shares of convertible preferred stock outstanding. We have no outstanding options to purchase common stock, however, we have granted restricted stock awards for approximately 2.2 million shares (other than shares cancelled or forfeited). On completion of this offering, we will have 138,171,022 outstanding shares of common stock.

Common Stock

Subject to any special voting rights of any series of preferred stock that we may issue in the future, each share of common stock has one vote on all matters voted on by our stockholders, including the election of our directors. Because holders of common stock do not have cumulative voting rights, the holders of a majority of the shares of common stock can elect all of the members of the board of directors standing for election, subject to the rights, powers and preferences of any outstanding series of preferred stock.

No share of common stock affords any preemptive rights or is convertible, redeemable, assessable or entitled to the benefits of any sinking or repurchase fund. Holders of common stock will be entitled to dividends in the amounts and at the times declared by our board of directors in its discretion out of funds legally available for the payment of dividends.

Holders of common stock will share equally in our assets on liquidation after payment or provision for all liabilities and any preferential liquidation rights of any preferred stock then outstanding. All outstanding shares of common stock are fully paid and non-assessable.

Preferred Stock

Convertible Preferred Stock

Dividends. Each holder of our convertible preferred stock is entitled to receive a quarterly cash dividend at an annual rate of 7.75% of the accreted value of each share of convertible preferred stock held by such holder. The accreted value is currently $210 per share. In lieu of making any such quarterly cash dividend, we may, at our option, increase the accreted value of each share of convertible preferred stock by 2.3125% of the existing accreted value. We are prohibited from paying any cash dividends on any capital stock junior or equal in rank to our convertible preferred stock, including our common stock, without the consent of holders of a majority of our outstanding convertible preferred stock. In addition, each holder is entitled to any dividend or distribution made with respect to our common stock as if such holder had converted its shares of convertible preferred stock to common stock on the record date.

Voting. Each holder of our convertible preferred stock is entitled to vote with the holders of our common stock on all matters submitted to a vote of stockholders as if such holder had converted its shares of convertible preferred stock to common stock on the record date for such vote. In addition, certain actions, including the issuance of any capital stock senior or equal in rank to our convertible preferred stock, any amendment to our Certificate of Incorporation and certain other fundamental transactions, shall require the approval of the holders of a majority of our convertible preferred stock.

Liquidation. In the event of any voluntary or involuntary liquidation, dissolution or winding-up of SandRidge, subject to the payments of any debts or other liabilities of SandRidge and prior to any payment to the holders of our common stock, each holder of our convertible preferred stock shall receive with respect to each share an amount equal to the greater of (i) the accreted value as of the date of the liquidation and (ii) the amount that such holder would have received had it converted its shares of convertible preferred stock on the date of such liquidation, dissolution or winding-up.

Conversion at the Option of the Holders. Each holder of our convertible preferred stock may convert any or all of its shares into common stock at any time. The shares of convertible preferred stock shall be converted into a number of shares of common stock equal to the product of the number of shares of convertible preferred stock being converted multiplied by the quotient of (i) the accreted value and (ii) the conversion price. The conversion price is currently $20.59 per share.

Issuances of common stock following this offering will not result in any adjustment to the conversion price.

Conversion at the Option of SandRidge. At any time after 180 days following this offering, if the conditions described below have been satisfied, we may, at our option, cause all the shares of convertible preferred stock to be converted into a number of shares of common stock equal to the number of shares of convertible preferred stock multiplied by the quotient of (i) the accreted value and (ii) the conversion price then in effect. We may not effect such a conversion unless the following conditions have been satisfied:

- we have completed this offering or an offering of similar size and price;
- the shelf registration statement required by the registration rights agreement entered into in connection with the issuance of the convertible preferred stock shall be effective;
- our common stock is listed on a national exchange and the closing price exceeds 100% of the conversion price for at least 20 trading days in any 30 consecutive trading day period; and
- certain other conditions, including no event of default.

In connection with any conversion by us, unless the closing price of our common stock exceeds 150% of the conversion price for at least 20 trading days in any 30 consecutive trading day period, we must also make a payment to each holder of shares of convertible preferred stock equal to (i) the accreted value, multiplied by (ii) 0.155.

Warrant to Purchase Convertible Preferred Stock

We have issued warrants to purchase 482,381 shares of our convertible preferred stock. Generally, the warrant entitles the warrantholder to exercise the warrant by tendering a certain number of shares of common stock purchased in connection with the warrant for a number of shares of convertible preferred stock with an aggregate accreted value at the time of exercise equal the number of shares of common stock tendered as exercise consideration multiplied by $19. The accreted value of a share of convertible preferred stock is subject to increase in the event of non-payment of preferred stock dividends in cash, in which event the number of shares of convertible preferred stock that may be issued upon exercise of the Warrant and tender of common stock will be reduced.

The warrant may be exercised in whole or in part (through the tender of whole shares of common stock) commencing on the date of issue and ending at 5:00 p.m., New York time, on the earlier of (i) May 15, 2013 and (ii) the first day in which all outstanding shares of convertible preferred stock have been fully redeemed or converted (voluntarily or involuntarily) pursuant to the Certificate of Designations of the convertible preferred stock. Holders of warrants are entitled to all notices delivered to holders of convertible preferred stock and certain other notices as set forth in the warrant.

Additional Preferred Stock

Our board of directors may, without any action by holders of the common stock:

- adopt resolutions to issue preferred stock in one or more classes or series;
- fix or change the number of shares constituting any class or series of preferred stock; and

establish or change the rights of the holders of any class or series of preferred stock.

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The rights of any class or series of preferred stock may include, among others:

- general or special voting rights;
- preferential liquidation or preemptive rights;
- preferential cumulative or noncumulative dividend rights;
- redemption or put rights; and
- conversion or exchange rights.

We may issue shares of, or rights to purchase, preferred stock the terms of which might:

- adversely affect voting or other rights evidenced by, or amounts otherwise payable with respect to, the common stock;
- discourage an unsolicited proposal to acquire us; or
- facilitate a particular business combination involving us.

Any of these actions could discourage a transaction that some or a majority of our stockholders might believe to be in their best interests or in which our stockholders might receive a premium for their stock over its then market price.

Amended and Restated Shareholders Agreement

In connection with the closing of the NEG acquisition, we entered into a Shareholders Agreement with certain of our shareholders, including Mr. Ward, our Chairman, Chief Executive Officer and President, Mr. Mitchell, a director, and affiliates of AREP. The Shareholders Agreement was subsequently amended and restated in connection with the sale of the shares held by AREP to other stockholders (the New Investors). The Amended and Restated Shareholders Agreement contains certain restrictions on transfer, tag-along rights and registration rights, each of which is described more fully below.

Transfer Restrictions. The Amended and Restated Shareholders Agreement prohibits the parties from transferring any of their securities prior to 180 days following the consummation of a qualified public offering, other than to family members and affiliates other than SandRidge or pursuant to the tagalong provisions described below. However, the Amended and Restated Shareholders Agreement allows Messrs. Ward and Mitchell to pledge their shares subject to certain conditions, in connection with a bona fide loan. The New Investors may also transfer their securities on the PORTAL market or pursuant to an exemption under the securities laws. Qualified public offering is defined as an underwritten, broad based public offering in excess of $100 million of common stock (which results in gross proceeds to the sellers of at least $100 million) and results in not less than 20 million shares of common stock (including common stock covered by any registration rights agreement and any shares sold pursuant to any previous public offerings) being listed for trading on a national securities exchange (including Nasdaq). We anticipate that this offering will be a qualified public offering for the purposes of the Amended and Restated Shareholders Agreement.

Tag-Along Rights. If Messrs. Ward or Mitchell propose to sell shares of common stock (other than to family members and affiliates other than SandRidge) prior to a qualified public offering, the New Investors have the right to elect to sell all of their shares of our common stock on the same terms. Following a qualified public offering, if Messrs. Ward or Mitchell propose to sell shares of our common stock in excess of 3% of our outstanding common stock on a fully diluted basis (other than to family members and affiliates other than SandRidge to Rule 144 or in a registered offering other than a block trade), the New Investors have the right to elect to sell their proportionate number of shares of our common stock on the same terms. The tag-along rights expire on the earlier of (i) the date upon which the New Investors cease to own at least 20% of our shares of common stock on purchased from affiliates of AREP and (ii) two years following the completion of this offering.

Registration Rights. The Amended and Restated Shareholders Agreement provides each of Mr. Ward, Mr. Mitchell and the affiliates of AREP certain registration rights. For a description of these rights, please read Registration Rights Amended and Restated Shareholders Agreement.

Ares Shareholder Agreement

In connection with our March 2007 private placement, we entered into a Shareholders Agreement (the Ares Shareholders Agreement) with certain affiliates of Ares Management LLC (Ares) and Mr. Ward. The Ares Shareholder Agreement contains tag-along rights and a voting requirement, each of which is described more fully below.

Tag-Along Rights. If Mr. Ward proposes to sell shares of common stock (other than to family members and affiliates other than SandRidge), he has agreed to use his commercially reasonable efforts to structure such sale in a manner as to allow Ares to sell the same proportionate amount of its shares on the same terms. To the extent Ares is unable to sell its proportionate amount of shares as a result of other tag-along rights, Mr. Ward shall decrease the amount of shares he is selling to allow for Ares to sell the same proportionate amount of its shares as Mr. Ward. The tag-along rights expire two years following the completion of this offering.

Voting Agreement. We have agreed, upon the request of Ares, to include its designee for director to be placed on the ballot for election at our 2008 annual meeting. In addition, Mr. Ward has agreed to vote his shares in favor of such designee at our 2008 annual meeting.

Registration Rights

December 2005 Private Placement. In connection with our December 2005 private placement, we agreed to use commercially reasonable efforts to file a shelf registration statement with the SEC with respect to the shares sold in our December 2005 private placement for resale prior to March 21, 2006 and to cause such shelf registration statement to become effective prior to July 29, 2006. This agreement was subsequently amended to extend the effectiveness date to December 21, 2007. If we fail to meet these deadlines or to maintain such effectiveness, we may be subject to certain liquidated damage payments. Please see Management s Discussion and Analysis of Financial Condition and Results of Operation Registration Rights Agreements. Stockholders party to this registration rights agreement are subject to lock-up provisions, which prohibit such holders from directly or indirectly, offering, selling, contracting to sell, pledging or otherwise disposing of or hedging any common stock or securities convertible into or exchangeable for shares of common stock, or publicly announcing the intention to do any of the foregoing, for a period from the date of this prospectus until the later of (i) 60 days following the date of this prospectus and (ii) January 1, 2008. This lock-up provision does not apply to securities purchased in this offering or following the completion of this offering. Please see Underwriting for a description of this lock-up provision.

November 2006 Private Placement. In connection with our November 2006 private placement, we agreed to file a shelf registration statement with the SEC with respect to the shares of our common stock underlying our convertible preferred stock as promptly as practicable, but in no event later than August 31, 2007. We also agreed to use our reasonable best efforts to cause such registration statement to become effective no later than the earlier of (i) 180 days from the effectiveness of the registration statement containing this prospectus and (ii) December 31, 2007. If we fail to meet these deadlines or to maintain such effectiveness, we may be subject to certain liquidated damage payments. Please see Management s Discussion and Analysis of Financial Condition and Results of Operation Registration Rights Agreements. In addition, we have agreed to allow the holders of the securities sold in our November 2006 private placement to offer their shares of our common stock in certain future registered offerings of our common stock, subject to our priority and customary limitations. Stockholders party to this registration rights agreement are subject to lock-up provisions, which prohibit such holders from directly or indirectly, offering, selling, contracting to sell, pledging or otherwise disposing of or hedging any common stock or securities convertible into or exchangeable for shares of common stock, or publicly announcing the intention to do any of the foregoing, for a period from the date of this prospectus until the later of (i) 60 days following the date of this prospectus and

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(ii) January 1, 2008. This lock-up provision does not apply to securities purchased in this offering or following the completion of this offering. Please see Underwriting for a description of this lock-up provision.

March 2007 Private Placement. In connection with our March 2007 private placement, we agreed to use commercially reasonable efforts to file a shelf registration statement with the SEC with respect to the shares sold in our March 2007 private placement for resale prior to either (a) 90 days following the effectiveness of the shelf registration statement related to our December 2005 private placement and (b) a date selected by the purchasers and to cause such shelf registration statement to become effective within 90 days of the date on which it is filed. If we fail to meet these deadlines or to maintain such effectiveness, we may be subject to certain liquidated damage payments. Please see Management s Discussion and Analysis of Financial Condition and Results of Operation Registration Rights Agreements. Stockholders party to this registration rights agreement are subject to lock-up provisions, which prohibit such holders from directly or indirectly, offering, selling, contracting to sell, pledging or otherwise disposing of or hedging any common stock or securities convertible into or exchangeable for shares of common stock, or publicly announcing the intention to do any of the foregoing, for a period from the date of this prospectus until the later of (i) 60 days following the date of this prospectus and (ii) January 1, 2008. This lock-up provision does not apply to securities purchased in this offering or following the completion of this offering. Please see Underwriting for a description of this lock-up provision.

Amended and Restated Shareholders Agreement. Pursuant to a Amended and Restated Shareholders Agreement among us and certain of our stockholders, including Messrs. Ward and Mitchell and certain of their respective affiliates, we have agreed to allow such parties to offer their shares of our common stock in certain future registered offerings of our common stock, subject to our priority and customary limitations. We have also agreed to use our reasonable best efforts to cause a shelf registration statement to become effective with respect to the securities held by the stockholders party to the Amended and Restated Shareholders Agreement upon their request. Such request may not be made within 120 days of the effectiveness of a registration statement requested pursuant to the Amended and Restated Shareholders Agreement or that such stockholders are entitled to participate in pursuant to the Amended and Restated Shareholders Agreement. In addition, the stockholders party to the agreement (other than Messrs. Ward and Mitchell and their affiliates) may not request that we file a shelf registration statement prior to the date which is 201 days following the consummation of this offering. The stockholders party to the agreement (other than Messrs. Ward and Mitchell and their affiliates) may transfer their registration rights under this agreement in connection with sales in excess of 2,000,000 shares of our common stock. Each of the parties to the Amended and Restated Shareholders Agreement have agreed not to effect any sale or distribution of our common stock or securities convertible or exchangeable or exercisable for our common stock for a period of 180 days from the date of this prospectus. The Amended and Restated Shareholders Agreement does not prohibit these stockholders from pledging their shares in connection with a bona fide borrowing arrangement. The agreement does, however, require that the lender or other beneficiary of such pledge agree to be bound by its terms upon any foreclosure to the extent the pledged shares represent more than 25% of such stockholders shares that are subject to the agreement.

Anti-Takeover Provisions of Delaware Law, Our Certificate of Incorporation and Bylaws

Written Consent of Stockholders

Our certificate of incorporation and bylaws provide that any action required or permitted to be taken by our stockholders must be taken at a duly called meeting of stockholders and not by written consent.

Amendment of the Bylaws

Under Delaware law, the power to adopt, amend or repeal bylaws is conferred upon the stockholders. A corporation may, however, in its certificate of incorporation also confer upon the board of directors the power to adopt, amend or repeal its bylaws. Our charter and bylaws grant our board the power to adopt, amend and repeal our bylaws on the affirmative vote of a majority of the directors then in office. Our stockholders may adopt, amend or repeal our bylaws but only at any regular or special meeting of stockholders by the holders of not less than 662/3% of the voting power of all outstanding voting stock.

Special Meetings of Stockholders

Our bylaws preclude the ability of our stockholders to call special meetings of stockholders.

Other Limitations on Stockholder Actions

Advance notice is required for stockholders to nominate directors or to submit proposals for consideration at meetings of stockholders. In addition, the ability of our stockholders to remove directors without cause is precluded.

Classified Board

Only one of three classes of directors is elected each year. See Management Board of Directors.

Limitation of Liability of Officers and Directors

Our certificate of incorporation provides that no director shall be personally liable to us or our stockholders for monetary damages for breach of fiduciary duty as a director, except for liability as follows:

- for any breach of the director s duty of loyalty to us or our stockholders;
- for acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of laws;
- for unlawful payment of a dividend or unlawful stock purchase or stock redemption; and
- for any transaction from which the director derived an improper personal benefit.

The effect of these provisions is to eliminate our rights and our stockholders rights, through stockholders derivative suits on our behalf, to recover monetary damages against a director for a breach of fiduciary duty as a director, including breaches resulting from grossly negligent behavior, except in the situations described above.

Business Combination Under Delaware Law

We are subject to the provisions of Section 203 of the Delaware General Corporation Law. In general, Section 203 prohibits a publicly held Delaware corporation from engaging in a business combination with an interested stockholder for a period of three years after the date of the transaction in which the person became an interested stockholder, unless the business combination is approved in a prescribed manner.

Section 203 defines a business combination as a merger, asset sale or other transaction resulting in a financial benefit to the interested stockholders. Section 203 defines an interested stockholder as a person who, together with affiliates and associates, owns, or, in some cases, within three years prior, did own, 15% or more of the corporation s voting stock. Under Section 203, a business combination between us and an interested stockholder is prohibited unless:

- our board of directors approved either the business combination or the transaction that resulted in the stockholders becoming an interested stockholder prior to the date the person attained the status;

upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of our voting stock outstanding at the time the transaction commenced, excluding, for purposes of determining the number of shares outstanding, shares owned by persons who are directors and also officers and issued employee stock plans, under which employee participants do not have the right to determine confidentially whether shares held under the plan will be tendered in a tender or exchange offer; or

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the business combination is approved by our board of directors on or subsequent to the date the person became an interested stockholder and authorized at an annual or special meeting of the stockholders by the affirmative vote of the holders of at least 662/3% of the outstanding voting stock that is not owned by the interested stockholder.

This provision has an anti-takeover effect with respect to transactions not approved in advance by our board of directors, including discouraging takeover attempts that might result in a premium over the market price for the shares of our common stock. With approval of our stockholders, we could amend our certificate of incorporation in the future to elect not to be governed by the anti-takeover law. This election would become effective twelve months after the adoption of the amendment and would not apply to any business combination with any person who became an interested stockholder on or before the adoption of the amendment.

SHARES ELIGIBLE FOR FUTURE SALE

Prior to this offering, there has been no public market for our common stock. The market price of our common stock could drop due to sales of a large number of shares of our common stock or the perception that these sales could occur. These factors could also make it more difficult to raise funds through future offerings of common stock.

After this offering, 138,171,022 shares of common stock will be outstanding, or 141,850,522 shares if the underwriters exercise their over-allotment option in full. Of these 138,171,022 shares, the 28,700,000 shares sold in this offering, or 32,379,500 shares if the underwriters exercise their over-allotment option in full, will be freely tradable without restriction under the Securities Act except for any shares purchased by one of our affiliates as defined in Rule 144 under the Securities Act. In addition, holders of 2,184,287 shares of our convertible preferred stock may convert such shares to common stock at any time. Following this offering and assuming the conversion of all outstanding shares of convertible preferred stock, 160,446,893 shares of common stock would be outstanding, or 164,126,393 shares if the underwriters exercise their over-allotment option in full. All of the shares outstanding other than the shares sold in this offering (a total of 109,471,022 shares) are restricted securities with the meaning of Rule 144 under the Securities Act.

In connection with this offering, we, all our executive officers and directors and N. Malone Mitchell, 3rd, have entered into lock-up agreements with the underwriters under which these holders of restricted shares have agreed that, subject to certain exceptions, they will not, directly or indirectly, offer, sell, contract to sell, pledge or otherwise dispose of or hedge any common stock or securities convertible into or exchangeable for shares of common stock, or publicly announce the intention to do any of the foregoing, without the prior written consent of Lehman Brothers Inc., Goldman, Sachs & Co. and Banc of America Securities LLC for a period of 180 days from the date of this prospectus. The lock-up agreement that Mr. Ward, our Chairman, Chief Executive Officer and President, entered into contains an exception for 6,584,098 restricted shares of our common stock that he pledged as a portion of the collateral for a personal loan and any additional shares of our common stock that he may pledge as collateral for such loan. If Mr. Ward defaults on this loan, the lender may foreclose on and sell these shares pursuant to an exemption under the Securities Act notwithstanding the lock-up agreement. The lock-up agreement of Mr. Mitchell, one of our directors, allows him to pledge up to all of his common shares as collateral for a personal loan provided that the lender agrees to be bound by the terms of Mr. Mitchell s lock-up with respect to any shares that are transferred to the lender as a result of foreclosure. See Underwriting for a description of these lock-up arrangements. There are additional restrictions on the transfer of shares by Messrs. Ward and Mitchell contained in the Amended and Restated Shareholders Agreement, dated as of April 4, 2007. The Amended and Restated Shareholders Agreement, however, also permits Messrs. Ward and Mitchell to pledge their shares, subject to certain conditions, in connection with a bona fide loan. See Description of Capital Stock Registration Rights Amended and Restated Shareholders Agreement.

Stockholders who acquired securities in our December 2005, November 2006 or March 2007 private placements are subject to lock-up provisions contained the registration rights agreements entered into in connection with such private placements. Pursuant to these lock-up provisions, as amended, these stockholders may not, directly or indirectly, offer, sell, contract to sell, pledge or otherwise dispose of or hedge any common stock or securities convertible into or exchangeable for shares of common stock, or publicly announce the intention to do any of the foregoing, for a period from the date of this prospectus until the later of (i) 60 days following the date of this prospectus and (ii) January 1, 2008. These lock-up provisions do not apply to securities purchased in this offering or following the completion of this offering.

Shareholders party to the Amended and Restated Shareholders Agreement, including Mr. Ward, Mr. Mitchell, and entities affiliated with Ares Management Fund LLC, have agreed not to effect any sale or distribution of our equity securities or securities convertible into or exchangeable or exercisable for any of our equity securities for a period of

180 days from the date of effectiveness of the registration statement containing this prospectus. The Amended and Restated Shareholders Agreement does not prohibit these stockholders from pledging their shares in connection with a bona fide borrowing arrangement. The agreement does, however, require that the lender or other beneficiary of such pledge agree to be bound by its terms upon any foreclosure

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to the extent the pledged shares represent more than 25% of such stockholders shares that are subject to the agreement. See Underwriting for a description of these lock-up agreements.

Giving effect to these lock-up agreements (but excluding the effect of the exclusion for Mr. Ward s pledged shares), the 109,471,022 restricted shares outstanding immediately prior to this offering will be eligible for sale in the public market under Rule 144 of the Securities Act, subject to volume limitations and other restrictions contained in Rule 144, as follows: (i) at the date of this prospectus 4,962,715 shares, (ii) commencing on the later of (a) 60 days thereafter and (b) January 1, 2008, an additional 21,312,313 shares, and (iii) commencing 180 days thereafter an additional 83,195,994 shares.

On August 13, 2007, we filed a shelf registration statement to register for resale, from time to time, by certain stockholders of up to 62,036,000 shares of our common stock issued or potentially issuable upon the conversion of securities sold in our December 2005, November 2006 and March 2007 private placements. We anticipate that this registration statement will be declared effective during the fourth quarter of 2007. All of the shares to be registered by the shelf registration statement are subject to the lock-up provisions described above related to our private placements.

As soon as practicable after this offering, we intend to file one or more registration statements with the SEC on Form S-8 providing for the registration of 7,074,252 shares of our common stock issued or reserved for issuance under our stock option plans. Subject to the exercise of unexercised options or the expiration or waiver of vesting conditions for restricted stock and the expiration of lock-ups we and certain of our stockholders have entered into, shares registered under these registration statements on Form S-8 will be available for resale immediately in the public market without restriction.

Rule 144

In general, under Rule 144 as currently in effect, any person (or persons whose shares are aggregated), including an affiliate, who has beneficially owned shares for a period of at least one year is entitled to sell, within any three-month period, a number of shares that does not exceed the greater of:

- 1% of the then outstanding shares of common stock, which will equal approximately 1,381,710 shares after the closing of this offering; and

- the average weekly trading volume of our common stock on the NYSE during the four calendar weeks immediately preceding the date on which the notice of the sale on Form 144 is filed with the Securities Exchange Commission.

Sales under Rule 144 are also subject to other provisions relating to notice and manner of sale and the availability of current public information about us. The SEC has a proposal pending to shorten the one-year holding period to six months.

Rule 144(k)

Under Rule 144(k), a person who is not deemed to have been one of our affiliates at any time during the 90 days preceding a sale, and who has beneficially owned the shares proposed to be sold for at least two years, including the holding period of any prior owner other than an affiliate (except in certain circumstances), is entitled to sell the shares without complying with the manner of sale, public information, volume limitation or notice provisions of Rule 144. Therefore, unless otherwise restricted, shares covered by Rule 144(k) may be sold immediately upon completion of this offering. The SEC has a proposal pending to shorten the two year holding period to one year.

Rule 701

In general under Rule 701 under the Securities Act as currently in effect, any of our employees who purchased or received shares from us in connection with a compensatory stock or option plan or other written agreement in a transaction that was completed in reliance on Rule 701 and complied with the requirements of Rule 701 is eligible to resell such shares beginning 90 days after the date of this prospectus in reliance on Rule 144, but without compliance with most of its restrictions, including the holding period.

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CERTAIN U.S. TAX CONSEQUENCES TO NON-U.S. HOLDERS

The following is a general discussion of the principal U.S. federal income and estate tax consequences of the ownership and disposition of our common stock by a non-U.S. holder. As used in this discussion, the term non-U.S. holder means a beneficial owner of our common stock that is not, for U.S. federal income tax purposes:

- an individual who is a citizen or resident of the United States;
- a corporation or partnership (including any entity treated as a corporation or partnership for U.S. federal income tax purposes) created or organized in or under the laws of the United States, or of any political subdivision of the United States (unless, in the case of a partnership, U.S. Treasury Regulations are adopted which provide otherwise);
- an estate whose income is subject to U.S. federal income taxation regardless of its source; or
- a trust, if a U.S. court is able to exercise primary supervision over the administration of the trust and one or more United States persons have the authority to control all substantial decisions of the trust, or if it has a valid election in effect under applicable U.S. Treasury Regulations to be treated as a United States person.

In any calendar year, an individual may be treated for U.S. federal income tax purposes as a resident of the United States by, among other ways, being present in the United States for at least 31 days in that calendar year and for an aggregate of at least 183 days during a three-year period ending in the current calendar year. For purposes of the 183-day calculation, all of the days on which such individual was present in the current year, one-third of the days in the immediately preceding year and one-sixth of the days in the second preceding year are counted. Residents are taxed for U.S. federal income tax purposes as if they were U.S. citizens. This discussion does not consider:

- U.S. state or local or non-U.S. tax consequences;
- all aspects of U.S. federal income and estate taxes or specific facts and circumstances that may be relevant to a particular non-U.S. holder s tax position, including, in the case of a non-U.S. holder that is an entity treated as a partnership for U.S. federal income tax purposes, the fact that the U.S. tax consequences of holding and disposing of our common stock may be affected by certain determinations made at the partner level;
- the tax consequences for the stockholders, partners or beneficiaries of a non-U.S. holder;
- special tax rules that may apply to particular non-U.S. holders, such as financial institutions, insurance companies, tax-exempt organizations, U.S. expatriates, broker-dealers, and traders in securities; or
- special tax rules that may apply to a non-U.S. holder that holds our common stock as part of a straddle, hedge, conversion transaction, synthetic security or other integrated investment.

The following discussion is based on provisions of the U.S. Internal Revenue Code of 1986, as amended (the Code), existing and proposed U.S. Treasury Regulations and administrative and judicial interpretations, all as of the date of this prospectus, and all of which are subject to change, retroactively or prospectively. The following summary assumes that a non-U.S. holder holds our common stock as a capital asset. **Each non-U.S. holder should consult a tax advisor regarding the U.S. federal, state, local and non-U.S. income and other tax consequences of acquiring, holding and disposing of shares of our common stock.**

Distributions on Common Stock

We do not expect to pay any cash distributions on our common stock in the foreseeable future; however, in the event that we do make such cash distributions, these distributions generally will constitute dividends for U.S. federal income tax purposes to the extent paid from our current or accumulated earnings and profits, as determined under U.S. federal income tax principles. Any amount paid in excess of such earnings and profits generally will be treated as a recovery of tax basis, to the extent thereof, and then gain from sale. Distributions

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paid to non-U.S. holders of our common stock that are not effectively connected with the non-U.S. holder s conduct of a U.S. trade or business generally will be subject to U.S. withholding tax at a 30% rate, or if a tax treaty applies, a lower rate specified by the treaty.

A non-U.S. holder that claims the benefit of an applicable income tax treaty generally will be required to provide an Internal Revenue Service Form W-8 BEN and meet certain other requirements. However,

- in the case of common stock held by a foreign partnership, the certification requirement will generally be applied to the partners of the partnership and the partnership will be required to provide certain information;
- in the case of common stock held by a foreign trust, the certification requirement will generally be applied to the trust or the beneficial owners of the trust depending on whether the trust is a foreign complex trust, foreign simple trust or foreign grantor trust as defined in the U.S. Treasury Regulations; and
- look-through rules will apply for tiered partnerships, foreign simple trusts and foreign grantor trusts.

A non-U.S. holder that is a foreign partnership or a foreign trust is urged to consult its own tax advisor regarding its status under these U.S. Treasury Regulations and the certification requirements applicable to it.

A non-U.S. holder that is eligible for a reduced rate of U.S. federal withholding tax under an income tax treaty may obtain a refund or credit of any excess amounts withheld by filing an appropriate claim for refund with the U.S. Internal Revenue Service. Non-U.S. holders should consult their tax advisors regarding their entitlement to benefits under a relevant income tax treaty.

Dividends that are effectively connected with a non-U.S. holder s conduct of a trade or business in the United States and, if an income tax treaty applies, are attributable to a permanent establishment in the United States, are taxed on a net income basis at the regular graduated rates and in the manner applicable to United States persons. In that case, we will not withhold U.S. federal withholding tax if the non-U.S. holder complies with applicable certification and disclosure requirements (including providing Internal Revenue Service Form W-8 ECI). In addition, a branch profits tax may be imposed at a 30% rate, or a lower rate under an applicable income tax treaty, on dividends received by a foreign corporation that are effectively connected with its conduct of a trade or business in the United States.

Disposition of Common Stock

We believe that we are a United States real property holding corporation. Generally, a corporation is a United States real property holding corporation if the fair market value of its United States real property interests equals or exceeds 50% of the sum of the fair market value of its worldwide real property interests and its other assets used or held for use in a trade or business. Notwithstanding our status as a United States real property holding corporation, a non-U.S. holder of our common stock generally will not be subject to U.S. federal income tax on gain recognized on a disposition of our common stock unless:

- the gain is effectively connected with the non-U.S. holder s conduct of a trade or business in the United States and, if an income tax treaty applies, is attributable to a permanent establishment maintained by the non-U.S. holder in the United States; in these cases, the gain will be taxed on a net income basis at the rates and in the manner applicable to United States persons, and if the non-U.S. holder is a foreign corporation, the branch profits tax described above may also apply;
- the non-U.S. holder is an individual who is present in the United States for 183 days or more in the taxable year of the disposition and meets other requirements; or

the non-U.S. holder actually or constructively owns more than five percent of our common stock at any time during the shorter of the five-year period ending on the date of disposition or the period that the non-U.S. holder held our common stock, provided that our common stock is regularly traded on an established securities market, within the meaning of Section 897 of the Code and applicable Treasury Regulations, during the calendar year in which the sale or other disposition occurs.

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Non-United States holders should consult their own tax advisors with respect to the application of the foregoing rules.

U.S. Federal Estate Tax

Common stock owned or treated as owned by an individual who is a non-U.S. holder for U.S. federal estate tax purposes at the time of death will be included in the individual s gross estate for U.S. federal estate tax purposes, unless an applicable estate tax or other treaty provides otherwise, and therefore may be subject to U.S. federal estate tax.

Information Reporting and Backup Withholding Tax

Generally, we must report annually to any non-U.S. holder and the U.S. Internal Revenue Service the amount of any dividends paid to such holder, the holder s name and address, and the amount, if any, of tax withheld. Copies of the information returns reporting those dividends and amounts withheld also may be made available to the tax authorities in the country in which the non-U.S. holder resides under the provisions of any applicable tax treaty or exchange of information agreement.

In addition to information reporting requirements, dividends paid to a non-U.S. holder may be subject to U.S. backup withholding tax. A non-U.S. holder generally will be exempt from this backup withholding tax, however, if such holder properly provides a Form W-8BEN certifying that such holder is a non-United States person or otherwise establishes an exemption and we do not know or have reason to know that the holder is a United States person.

The gross proceeds from the disposition of our common stock may be subject to information reporting and backup withholding. If a non-U.S. holder sells shares of our common stock outside the United States through a non-U.S. office of a non-U.S. broker and the sales proceeds are paid to such holder outside the United States, then the U.S. backup withholding and information reporting requirements generally will not apply to that payment. However, U.S. information reporting, but not backup withholding, generally will apply to a payment of sales proceeds, even if that payment is made outside the United States, if the non-U.S. holder sells shares of our common stock through a non-U.S. office of a broker that:

- is a United States person;
- derives 50% or more of its gross income in specific periods from the conduct of a trade or business in the United States;
- is a controlled foreign corporation for U.S. federal tax purposes; or
- is a foreign partnership, if at any time during its tax year:
  - one or more of its partners are United States persons who in the aggregate hold more than 50% of the income or capital interests in the partnership; or
  - the foreign partnership is engaged in a U.S. trade or business,

unless the broker has documentary evidence in its files that the holder is not a U.S. person and certain other conditions are met, or the holder otherwise establishes an exemption.

If a non-U.S. holder receives payments of the proceeds of a sale of our common stock to or through a U.S. office of a broker, the payment will be subject to both U.S. backup withholding and information reporting unless such holder properly provides a Form W-8BEN certifying that such holder is not a United States person or otherwise establishes an exemption, and we do not know or have reason to know that such holder is a United States person.

A non-U.S. holder generally may obtain a refund of any amounts withheld under the backup withholding rules that exceed such holder s U.S. federal income tax liability by timely filing a properly completed claim for refund with the U.S. Internal Revenue Service.

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UNDERWRITING

Lehman Brothers Inc., Goldman, Sachs & Co. and Banc of America Securities LLC are acting as representatives of the underwriters and joint book-running managers of this offering. Under the terms of an underwriting agreement, which will be filed as an exhibit to the registration statement, each of the underwriters named below has severally agreed to purchase from us the respective number of common stock shown opposite its name below:

Underwriters	Number of Shares
Lehman Brothers Inc.	6,132,500
Goldman, Sachs & Co.	6,132,500
Banc of America Securities LLC	2,453,000
Bear, Stearns & Co. Inc.	1,471,800
Credit Suisse Securities (USA) LLC	1,471,800
Deutsche Bank Securities Inc.	1,471,800
J.P. Morgan Securities Inc.	1,471,800
UBS Securities LLC	1,471,800
Howard Weil Incorporated	490,600
Raymond James & Associates, Inc.	490,600
RBC Capital Markets Corporation	490,600
Simmons & Company International	490,600
Tudor, Pickering & Co. Securities, Inc.	490,600
Total	24,530,000

In addition, we will directly offer and sell at the public offering price 4,170,000 shares to an entity controlled by Tom L. Ward, our Chairman, Chief Executive Officer and largest stockholder. Mr. Ward is not currently obligated to purchase these shares. These shares are not part of the underwritten offering and the underwriters will not participate as an underwriter, placement agent or in any other offeror capacity in connection with any sale of, and will not receive any commission or discount on, these shares.

The underwriting agreement provides that the underwriters obligation to purchase shares of common stock depends on the satisfaction of the conditions contained in the underwriting agreement including:

the obligation to purchase all of the shares of common stock offered hereby (other than those shares of common stock covered by their option to purchase additional shares as described below), if any of the shares are purchased;

the representations and warranties made by us to the underwriters are true;

there is no material change in our business or the financial markets; and

we deliver customary closing documents to the underwriters.

Commissions and Expenses

The following table summarizes the underwriting discounts and commissions we will pay to the underwriters. These amounts are shown assuming both no exercise and full exercise of the underwriters option to purchase additional shares. The underwriting fee is the difference between the initial price to the public and the amount the underwriters pay to us for the shares.

	Paid by Us	
	No Exercise	**Full Exercise**
Per Share	$ 1.56	$ 1.56
Total	$ 38,266,800	$ 44,006,820

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The representatives of the underwriters have advised us that the underwriters propose to offer the shares of common stock directly to the public at the public offering price on the cover of this prospectus and to selected dealers, which may include the underwriters, at such offering price less a selling concession not in excess of $0.94 per share. After the offering, the representatives may change the offering price and other selling terms.

The expenses of the offering that are payable by us are estimated to be $2.5 million (excluding underwriting discounts and commissions).

Option to Purchase Additional Shares

We have granted the underwriters an option exercisable for 30 days after the date of the underwriting agreement, to purchase, at any one time, in whole or in part, up to an aggregate of 3,679,500 shares at the public offering price less underwriting discounts and commissions. This option may be exercised if the underwriters sell more than the number of shares on the cover of this prospectus in connection with this offering. To the extent that this option is exercised, each underwriter will be obligated, subject to certain conditions, to purchase its pro rata portion of these additional shares based on the underwriter s underwriting commitment in the offering as indicated in the table at the beginning of this Underwriting Section.

Lock-Up Agreements

We, all of our executive officers and directors and N. Malone Mitchell, 3rd have agreed that, subject to certain exceptions, without the prior written consent of each of Lehman Brothers Inc., Goldman, Sachs & Co. and Banc of America Securities LLC, we and they will not directly or indirectly, (1) offer for sale, sell, pledge, or otherwise dispose of (or enter into any transaction or device that is designed to, or could be expected to, result in the disposition by any person at any time in the future of) any shares of common stock (including, without limitation, shares of common stock that may be deemed to be beneficially owned by us or them in accordance with the rules and regulations of the Securities and Exchange Commission and shares of common stock that may be issued upon exercise of any options or warrants) or securities convertible into or exercisable or exchangeable for common stock, (2) enter into any swap or other derivatives transaction that transfers to another, in whole or in part, any of the economic consequences of ownership of the common stock, (3) make any demand for or exercise any right or file or cause to be filed a registration statement, including any amendments thereto, with respect to the registration of any shares of common stock or securities convertible, exercisable or exchangeable into common stock or any of our other securities, or (4) publicly disclose the intention to do any of the foregoing for a period of 180 days after the date of this prospectus. The lock-up agreement that Mr. Ward, our Chairman, Chief Executive Officer and President, entered into contains an exception for approximately 6,584,098 restricted shares of our common stock that he pledged as a portion of the collateral for a personal loan and any additional shares of our common stock he may pledge as collateral for such loan. If Mr. Ward defaults on this loan, the lender may foreclose on and sell these shares pursuant to an exemption under the Securities Act notwithstanding the lock-up agreement. The lock-up agreement of Mr. Mitchell, one of our directors, allows him to pledge up to all of his common shares as collateral for a personal loan provided that the lender agrees to be bound by the terms of Mr. Mitchell s lock-up with respect to any shares that are transferred to the lender as a result of foreclosure. Please see Risk Factors Risks Related to this Offering and Our Common Stock Certain stockholders shares are restricted from immediate resale but may be sold in the market in the near future. This could cause the market price of our common stock to drop significantly. There are additional restrictions on the transfer of shares by Messrs. Ward and Mitchell contained in the Amended and Restated Shareholders Agreement, dated as of April 4, 2007. The Amended and Restated Shareholders Agreement, however, also permits Messrs. Ward and Mitchell to pledge their shares, subject to certain conditions, in connection with a bona fide loan. See Description of Capital Stock Registration Rights Amended and Restated Shareholders Agreement.

The 180-day restricted period described in the preceding paragraph will be extended if:

during the last 17 days of the 180-day restricted period we issue an earnings release or material news or a material event relating to us occurs; or

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prior to the expiration of the 180-day restricted period, we announce that we will release earnings results during the 16-day period beginning on the last day of the 180-day period,

in which case the restrictions described in the preceding paragraph will continue to apply until the expiration of the 18-day period beginning on the issuance of the earnings release or the announcement of the material news or occurrence of a material event, unless such extension is waived in writing by Lehman Brothers Inc., Goldman, Sachs & Co. and Banc of America Securities LLC.

Lehman Brothers Inc., Goldman, Sachs & Co. and Banc of America Securities LLC, in their sole discretion, may release the common stock and other securities subject to the lock-up agreements described above in whole or in part at any time with or without notice. When determining whether or not to release common stock and other securities from lock-up agreements, Lehman Brothers Inc., Goldman, Sachs & Co. and Banc of America Securities LLC will consider, among other factors, the holder s reasons for requesting the release, the number of shares of common stock and other securities for which the release is being requested and market conditions at the time.

Lehman Brothers Inc., Goldman, Sachs & Co. and Banc of America Securities LLC have no present intent or understanding to release all or any portion of the securities subject to these arrangements.

As described below under Directed Share Program, any participants in the Directed Share Program will be subject to a 180-day lock up with respect to any shares sold to them pursuant to that program. This lock up will include an identical extension provision with respect to an earnings release, material news or event as the lock-up agreement described above. Any shares sold in the Directed Share Program to our directors or officers will be subject to the lock-up agreement described above.

Stockholders who acquired securities in our December 2005, November 2006 or March 2007 private placements are subject to lock-up provisions contained the registration rights agreements entered into in connection with such private placements. Pursuant to these lock-up provisions, such stockholders may not, directly or indirectly, (1) offer for sale, sell, pledge, or otherwise dispose of (or enter into any transaction or device that is designed to, or could be expected to, result in the disposition by any person at any time in the future of) any shares of common stock (including, without limitation, shares of common stock that may be deemed to be beneficially owned by us or them in accordance with the rules and regulations of the Securities and Exchange Commission and shares of common stock that may be issued upon exercise of any options or warrants) or securities convertible into or exercisable or exchangeable for common stock, (2) enter into any swap or other derivatives transaction that transfers to another, in whole or in part, any of the economic consequences of ownership of the common stock or (3) publicly disclose the intention to do any of the foregoing, for a period from the date of this prospectus until the later of (i) 60 days following the date of this prospectus and (ii) January 1, 2008. This lock-up provision does not apply to securities purchased in this offering or following the completion of this offering.

Shareholders party to the Amended and Restated Shareholders Agreement, including Mr. Ward, Mr. Mitchell and entities affiliated with Ares Management Fund LLC, have agreed not to effect any sale or distribution of our equity securities or securities convertible into or exchangeable or exercisable for any of our equity securities for a period of 180 days from the date of effectiveness of the registration statement containing this prospectus. The Amended and Restated Shareholders Agreement does not prohibit these stockholders from pledging their shares in connection with a bona fide borrowing arrangement. The agreement does, however, require that the lender or other beneficiary of such pledge agree to be bound by its terms upon any foreclosure to the extent the pledged shares represent more than 25% of such stockholders shares that are subject to the agreement.

Offering Price Determination

Prior to this offering, there has been no public market for our common stock. The initial public offering price was negotiated between the representatives and us. In determining the initial public offering price of our common stock, the representatives considered:

- the history and prospects for the industry in which we compete;
- our financial information;
- the ability of our management and our business potential and earning prospects;
- the prevailing securities markets at the time of this offering; and
- the recent market prices of, and the demand for, publicly traded shares of generally comparable companies.

Indemnification

We have agreed to indemnify the underwriters against certain liabilities, including liabilities under the Securities Act and liabilities incurred in connection with the directed share program referred to below, and to contribute to payments that the underwriters may be required to make for these liabilities.

Directed Share Program

At our request, the underwriters have reserved for sale at the initial public offering price up to 5% of the shares offered hereby for officers, directors, employees and certain other persons associated with us. These shares are in addition to the 4,170,000 shares we are offering directly to TLW Properties, L.L.C., an entity controlled by Mr. Ward. The number of shares available for sale to the general public will be reduced to the extent such persons purchase such reserved shares. Any reserved shares not so purchased will be offered by the underwriters to the general public on the same basis as the other shares offered hereby. Any participants in this program will be prohibited from selling, pledging or assigning any shares sold to them pursuant to this program for a period of 180 days after the date of this prospectus. This 180-day lock up period will be extended with respect to our issuance of an earnings release, or if a material news or a material event relating to us occurs, in the same manner as described above under Lock-Up Agreements.

Stabilization, Short Positions and Penalty Bids

The representatives may engage in stabilizing transactions, short sales and purchases to cover positions created by short sales, and penalty bids or purchases for the purpose of pegging, fixing or maintaining the price of the common stock, in accordance with Regulation M under the Securities Exchange Act of 1934:

- Stabilizing transactions permit bids to purchase the underlying security so long as the stabilizing bids do not exceed a specified maximum.
- A short position involves a sale by the underwriters of shares in excess of the number of shares the underwriters are obligated to purchase in the offering, which creates the syndicate short position. This short position may be either a covered short position or a naked short position. In a covered short position, the number of shares involved in the sales made by the underwriters in excess of the number of shares they are obligated to purchase is not greater than the number of shares that they may purchase by exercising their option

to purchase additional shares. In a naked short position, the number of shares involved is greater than the number of shares in their option to purchase additional shares. The underwriters may close out any short position by either exercising their option to purchase additional shares and/or purchasing shares in the open market. In determining the source of shares to close out the short position, the underwriters will consider, among other things, the price of shares available for purchase in the open market as compared to the price at which they may purchase shares through their option to purchase additional shares. A naked short position is more likely to be created if the underwriters are concerned that there could be downward pressure on the price of the shares in the open market after pricing that could adversely affect investors who purchase in the offering.

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Syndicate covering transactions involve purchases of the common stock in the open market after the distribution has been completed in order to cover syndicate short positions.

Penalty bids permit the representatives to reclaim a selling concession from a syndicate member when the common stock originally sold by the syndicate member is purchased in a stabilizing or syndicate covering transaction to cover syndicate short positions.

These stabilizing transactions, syndicate covering transactions and penalty bids may have the effect of raising or maintaining the market price of our common stock or preventing or retarding a decline in the market price of the common stock. As a result, the price of the common stock may be higher than the price that might otherwise exist in the open market. These transactions may be effected on The New York Stock Exchange or otherwise and, if commenced, may be discontinued at any time.

Neither we nor any of the underwriters make any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of the common stock. In addition, neither we nor any of the underwriters make representation that the representatives will engage in these stabilizing transactions or that any transaction, once commenced, will not be discontinued without notice.

Electronic Distribution

A prospectus in electronic format may be made available on the Internet sites or through other online services maintained by one or more of the underwriters and/or selling group members participating in this offering, or by their affiliates. In those cases, prospective investors may view offering terms online and, depending upon the particular underwriter or selling group member, prospective investors may be allowed to place orders online. The underwriters may agree with us to allocate a specific number of shares for sale to online brokerage account holders. Any such allocation for online distributions will be made by the representatives on the same basis as other allocations.

Other than the prospectus in electronic format, the information on any underwriter s or selling group member s web site and any information contained in any other web site maintained by an underwriter or selling group member is not part of the prospectus or the registration statement of which this prospectus forms a part, has not been approved and/or endorsed by us or any underwriter or selling group member in its capacity as underwriter or selling group member and should not be relied upon by investors.

New York Stock Exchange

Our shares of common stock have been approved to be listed for quotation on the New York Stock Exchange under the symbol SD. The underwriters have undertaken to sell the shares of common stock in this offering to a minimum of 400 beneficial owners in round lots of 100 or more units to meet the New York Stock Exchange distribution requirements for trading.

Discretionary Sales

The underwriters have informed us that they do not intend to confirm sales to discretionary accounts without the prior written approval of the customers.

Stamp Taxes

If you purchase shares of common stock offered in this prospectus, you may be required to pay stamp taxes and other charges under the laws and practices of the country of purchase, in addition to the offering price listed on the cover page of this prospectus.

United Kingdom

To the extent that any offer of the common stock is made in the United Kingdom, this document is only being distributed to and is only directed at (i) investment professionals falling within Article 19(5) of the

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Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the Order) or (ii) high net worth entities, and other persons to whom it may lawfully be communicated, falling within Article 492(a) to (e) of the Order (all such persons together being referred to as relevant persons). The shares of common stock are only available to, and any invitation, offer or agreement to subscribe, purchase or otherwise acquire such common stock will be engaged in only with, relevant persons. Any person who is not a relevant person should not act or rely on this document or any of its contents.

Each of the underwriters has represented and agreed that:

(a) it has only communicated or caused to be communicated and will only communicate or cause to be communicated an invitation or inducement to engage in investment activity (within the meaning of Section 21 of the Financial Services and Markets Act 2000 or FSMA) received by it in connection with the issue or sale of the shares in circumstances in which Section 21(1) of the FSMA does not apply to us, and

(b) it has complied with, and will comply with all applicable provisions of the FSMA with respect to anything done by it in relation to the shares in, from or otherwise involving the United Kingdom.

European Economic Area

To the extent that the offer of the common stock is made in any Member State of the European Economic Area that has implemented the Prospectus Directive before the date of publication of a prospectus in relation to the common stock which has been approved by the competent authority in the Member State in accordance with the Prospectus Directive (or, where appropriate, published in accordance with the Prospectus Directive and notified to the competent authority in the Member State in accordance with the Prospectus Directive), the offer (including any offer pursuant to this document) is only addressed to qualified investors in that Member State within the meaning of the Prospectus Directive or has been or will be made otherwise in circumstances that do not require us to publish a prospectus pursuant to the Prospectus Directive.

In relation to each Member State of the European Economic Area which has implemented the Prospectus Directive (each, a Relevant Member State), each underwriter has represented and agreed that with effect from and including the date on which the Prospectus Directive is implemented in that Relevant Member State (the Relevant Implementation Date) it has not made and will not make an offer of shares to the public in that Relevant Member State prior to the publication of a prospectus in relation to the shares which has been approved by the competent authority in that Relevant Member State or, where appropriate, approved in another Relevant Member State and notified to the competent authority in that Relevant Member State, all in accordance with the Prospectus Directive, except that it may, with effect from and including the Relevant Implementation Date, make an offer of shares to the public in that Relevant Member State at any time:

(a) to legal entities which are authorized or regulated to operate in the financial markets or, if not so authorized or regulated, whose corporate purpose is solely to invest in securities,

(b) to any legal entity which has two or more of (1) an average of at least 250 employees during the last financial year; 2 a total balance sheet of more than 43,000,000 and (3) an annual net turnover of more than 50,000,000, as shown in its last annual or consolidated accounts,

(c) to fewer than 100 natural or legal persons (other than qualified investors as defined in the Prospectus Directive) subject to obtaining the prior consent of the representatives for any such offer, or

(d) in any other circumstances which do not require the publication by us of a prospectus pursuant to Article 3 of the Prospectus Directive.

For the purposes of this provision, the expression an offer of shares to the public in relation to any shares in any Relevant Member State means the communication in any form and by any means of sufficient information on the terms of the offer and the shares to be offered so as to enable an investor to decide to purchase or subscribe the shares, as the same may be varied in that Member State by any measure implementing the Prospectus Directive in that Member State and the expression Prospectus Directive means Directive 2003/71/EC and includes any relevant implementing measure in each Relevant Member State.

Hong Kong

The shares may not be offered or sold by means of any document other than (i) in circumstances which do not constitute an offer to the public within the meaning of the Companies Ordinance (Cap. 32, Laws of Hong Kong), or (ii) to professional investors within the meaning of the Securities and Futures Ordinance (Cap. 571, Laws of Hong Kong) and any rules made thereunder, or (iii) in other circumstances which do not result in the document being a prospectus within the meaning of the Companies Ordinance (Cap. 32, Laws of Hong Kong), and no advertisement, invitation or document relating to the shares may be issued or may be in the possession of any person for the purpose of issue (in each case whether in Hong Kong or elsewhere), which is directed at, or the contents of which are likely to be accessed or read by, the public in Hong Kong (except if permitted to do so under the laws of Hong Kong) other than with respect to shares which are or are intended to be disposed of only to persons outside Hong Kong or only to professional investors within the meaning of the Securities and Futures Ordinance (Cap. 571, Laws of Hong Kong) and any rules made thereunder.

Singapore

This prospectus has not been registered as a prospectus with the Monetary Authority of Singapore. Accordingly, this prospectus and any other document or material in connection with the offer or sale, or invitation for subscription or purchase, of the shares may not be circulated or distributed, nor may the shares be offered or sold, or be made the subject of an invitation for subscription or purchase, whether directly or indirectly, to persons in Singapore other than (i) to an institutional investor under Section 274 of the Securities and Futures Act, Chapter 289 of Singapore (the SFA), (ii) to a relevant person, or any person pursuant to Section 275(1A), and in accordance with the conditions, specified in Section 275 of the SFA or (iii) otherwise pursuant to, and in accordance with the conditions of, any other applicable provision of the SFA.

Where the shares are subscribed or purchased under Section 275 by a relevant person which is: (a) a corporation (which is not an accredited investor) the sole business of which is to hold investments and the entire share capital of which is owned by one or more individuals, each of whom is an accredited investor; or (b) a trust (where the trustee is not an accredited investor) whose sole purpose is to hold investments and each beneficiary is an accredited investor, shares, debentures and units of shares and debentures of that corporation or the beneficiaries rights and interest in that trust shall not be transferable for 6 months after that corporation or that trust has acquired the shares under Section 275 except: (1) to an institutional investor under Section 274 of the SFA or to a relevant person, or any person pursuant to Section 275(1A), and in accordance with the conditions, specified in Section 275 of the SFA; (2) where no consideration is given for the transfer; or (3) by operation of law.

Japan

The securities have not been and will not be registered under the Securities and Exchange Law of Japan (the Securities and Exchange Law) and each underwriter has agreed that it will not offer or sell any securities, directly or indirectly, in Japan or to, or for the benefit of, any resident of Japan (which term as used herein means any person resident in Japan, including any corporation or other entity organized under the laws of Japan), or to others for re-offering or resale, directly or indirectly, in Japan or to a resident of Japan, except pursuant to an exemption from the registration requirements of, and otherwise in compliance with, the Securities and Exchange Law and any other applicable laws, regulations and ministerial guidelines of Japan.

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France

No prospectus (including any amendment, supplement or replacement thereto) has been prepared in connection with the offering of the common stock that has been approved by the Autorité des marchés financiers or by the competent authority of another State that is a contracting party to the Agreement on the European Economic Area and notified to the Autorité des marchés financiers; no Securities have been offered or sold and will be offered or sold, directly or indirectly, to the public in France except to permitted investors (Permitted Investors) consisting of persons licensed to provide the investment service of portfolio management for the account of third parties, qualified investors (investisseurs qualifiés) acting for their own account and/or investors belonging to a limited circle of investors (cercle restreint d investisseurs) acting for their own account, with qualified investors and limited circle of investors having the meaning ascribed to them in Articles L. 411-2, D. 411-1, D. 411-2, D. 411-4, D. 734-1, D. 744-1, D. 754-1 and D. 764-1 of the French Code Monétaire et Financier and applicable regulations thereunder; none of this prospectus or any other materials related to the offering or information contained therein relating to the Securities has been released, issued or distributed to the public in France except to Permitted Investors; and the direct or indirect resale to the public in France of any Securities acquired by any Permitted Investors may be made only as provided by Articles L. 411-1, L. 411-2, L. 412-1 and L. 621-8 to L. 621-8-3 of the French Code Monétaire et Financier and applicable regulations thereunder.

Italy

The offering of the common stock has not been cleared by the Italian Securities Exchange Commission (Commissione Nazionale per le Società e la Borsa, the CONSOB) pursuant to Italian securities legislation and, accordingly, the common stock may not be offered, sold or delivered, nor may copies of this prospectus or any other documents relating to the common stock be distributed in Italy, except (i) to professional investors (operatori qualificati), as defined in Article 31, second paragraph, of CONSOB Regulation No. 11522 of July 1, 1998, as amended, (the Regulation No. 11522), or (ii) in other circumstances which are exempted from the rules on solicitation of investments pursuant to Article 100 of Legislative Decree No. 58 of February 24, 1998 (the Financial Service Act) and Article 33, first paragraph, of CONSOB Regulation No. 11971 of May 14, 1999, as amended.

Any offer, sale or delivery of the common stock or distribution of copies of this prospectus or any other document relating to the common stock in Italy may and will be effected in accordance with all Italian securities, tax, exchange control and other applicable laws and regulations, and, in particular, will be: (i) made by an investment firm, bank or financial intermediary permitted to conduct such activities in Italy in accordance with the Financial Services Act, Legislative Decree No. 385 of September 1, 1993, as amended (the Italian Banking Law), Regulation No. 11522, and any other applicable laws and regulations; (ii) in compliance with Article 129 of the Italian Banking Law and the implementing guidelines of the Bank of Italy; and (iii) in compliance with any other applicable notification requirement or limitation which may be imposed by CONSOB or the Bank of Italy.

Any investor purchasing the common stock in the offering is solely responsible for ensuring that any offer or resale of the common stock it purchased in the offering occurs in compliance with applicable laws and regulations.

This prospectus and the information contained therein are intended only for the use of its recipient and, unless in circumstances which are exempted from the rules on solicitation of investments pursuant to Article 100 of the Financial Service Act and Article 33, first paragraph, of CONSOB Regulation No. 11971 of May 14, 1999, as amended, is not to be distributed, for any reason, to any third party resident or located in Italy. No person resident or located in Italy other than the original recipients of this document may rely on it or its content.

Italy has only partially implemented the Prospectus Directive, the provisions under the heading European Economic Area above shall apply with respect to Italy only to the extent that the relevant provisions of the Prospectus Directive have already been implemented in Italy.

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Insofar as the requirements above are based on laws which are superseded at any time pursuant to the implementation of the Prospectus Directive, such requirements shall be replaced by the applicable requirements under the Prospectus Directive.

Relationships/NASD Conduct Rules

The underwriters have in the past performed and may in the future perform investment banking and advisory services for us from time to time for which they received and may in the future receive customary fees and expenses. In particular, Lehman Brothers Inc., Goldman, Sachs & Co. and Banc of America Securities LLC hold shares of our convertible preferred stock. Affiliates of Banc of America Securities LLC, Credit Suisse Securities (USA) LLC, Deutsche Bank Securities Inc. and RBC Capital Markets Corporation are lenders under our senior credit facility, which we intend to repay with the net proceeds of this offering. Because of this relationship, this offering is being conducted in accordance with Rule 2720 of the National Association of Securities Dealers, Inc. This rule requires that the initial public offering price for our shares cannot be higher than the price recommended by a qualified independent underwriter, as defined by the NASD. Lehman Brothers Inc. is serving as a qualified independent underwriter and will assume the customary responsibilities of acting as a qualified independent underwriter in pricing the offering and conducting due diligence. We have agreed to indemnify Lehman Brothers Inc. against any liabilities arising in connection with its role as a qualified independent underwriter, including liabilities under the Securities Act. Under the rules of FINRA (formerly known as the National Association of Securities Dealers, Inc. or NASD), Bear, Stearns & Co. Inc. has received underwriting compensation of $133,328 as a result of the acquisition of our shares by two of its employees in March 2007.

LEGAL MATTERS

The validity of the shares offered hereby will be passed upon for us by Vinson & Elkins L.L.P. Certain legal matters in connection with the offering will be passed upon for the underwriters by Davis Polk & Wardwell.

EXPERTS

The financial statements of SandRidge Energy, Inc. as of December 31, 2005 and 2006 and for each of the three years in the period ended December 31, 2006 included in this Prospectus have been so included in reliance on the report of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

The combined financial statements of NEG Oil & Gas LLC and subsidiaries, excluding National Energy Group, Inc. and the 103/4% Senior Notes due from National Energy Group Inc., but including National Energy Group Inc. s 50% membership interest in NEG Holding LLC as of December 31, 2004 and 2005 and for each of the three years in the period ended December 31, 2005 included in this prospectus and elsewhere in the registration statement have been audited by Grant Thornton LLP, independent registered public accounting firm, as indicated in their report with respect thereto, and is included herein in reliance upon the authority of said firm as experts in giving said report.

The estimated reserve evaluations and related calculations for our WTO properties as of December 31, 2005 and PetroSource properties as of December 31, 2005 and 2006 and June 30, 2007 have been included in this prospectus in reliance upon the report of DeGolyer and MacNaughton, independent petroleum engineering consultants, given upon their authority as experts in petroleum engineering. The estimated reserve evaluations and related calculations for our Piceance Basin properties as of December 31, 2005 and our WTO, East Texas, Gulf of Mexico, Gulf Coast and certain other properties as of December 31, 2006 and June 30, 2007 have been included in this prospectus in reliance upon the report of Netherland, Sewell & Associates, Inc., independent petroleum engineering consultants, given upon their authority as experts in petroleum engineering. The estimated reserve evaluations for certain of our other properties as of December 31, 2005 have been included in this report in reliance upon the report of Harper & Associates, Inc., independent petroleum engineering consultants, given upon their authority as experts in petroleum engineering.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC a registration statement on Form S-1 under the Securities Act with respect to the common stock being sold in this offering. This prospectus, which forms part of the registration statement, does not contain all of the information set forth in the registration statement and the exhibits and schedules to the registration statement. For further information with respect to us and our common stock being sold in this offering, we refer you to the registration statement and the exhibits and schedules filed as a part of the registration statement. Statements contained in this prospectus concerning the contents of any contract or any other document are not necessarily complete. If a contract or document has been filed as an exhibit to the registration statement, we refer you to the copy of the contract or document that has been filed as an exhibit and is qualified in all respects by the filed exhibit. The registration statement, including exhibits and schedules filed, may be inspected without charge at the Public Reference Room of the SEC at 100 F Street, NE, Washington, D.C. 20549, and copies of all or any part of it may be obtained from that office after payment of fees prescribed by the SEC. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC maintains a website that contains reports, proxy and information statements and other information regarding registrants that file electronically with the SEC at http://www.sec.gov. The other information we file with the SEC is not part of the registration statement of which this prospectus forms a part.

After we have completed this offering, we will file annual, quarterly and current reports, proxy statements and other information with the SEC. We intend to make these filings available on our website at http://www.sandridgeenergy.com once the offering is completed. Information on, or accessible through, this website is not a part of, and is not incorporated into, this prospectus. In addition, we will provide copies of our filings free of charge to our stockholders upon request.

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FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Board of Directors
and Stockholders of SandRidge Energy, Inc.

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, changes in stockholders equity and of cash flows present fairly, in all material respects, the financial position of SandRidge Energy, Inc. and its subsidiaries at December 31, 2005 and 2006, and the results of their operations and their cash flows for each of the three years then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the financial statements, the Company changed the manner in which it accounts for oil and gas operations from the successful efforts method to the full cost method in 2006, and accordingly, the financial statements have been retroactively restated. Also, as discussed in Note 1, the 2006 consolidated financial statements have been restated to correct the fair value of derivative contracts.

PricewaterhouseCoopers LLP

Houston, Texas
March 30, 2007, except for Restatement section of Note 1 to the consolidated financial statements, as to which the date is May 11, 2007.

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SandRidge Energy, Inc. and Subsidiaries

Consolidated Balance Sheets

	As of December 31, 2005 (Restated)	As of December 31, 2006 (Restated)
	(In thousands except per share amount)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 45,731	$ 38,948
Restricted cash	2,373	
Accounts receivable, net:		
Trade	59,180	89,774
Related parties	5,376	5,731
Inventories	1,606	2,544
Deferred income taxes	1,323	6,315
Other current assets	3,244	31,494
Total current assets	118,833	174,806
Oil and natural gas properties, using full cost method of accounting		
Proved	160,789	1,636,832
Unproved	33,974	282,374
Less: accumulated depreciation and depletion	(35,029)	(60,752)
	159,734	1,858,454
Other property, plant and equipment, net	178,147	276,264
Goodwill		26,198
Investments	1,614	3,584
Restricted deposits		33,189
Other assets	355	15,889
Total assets	$ 458,683	$ 2,388,384
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Current maturities of long-term debt	$ 12,997	$ 26,201
Accounts payable and accrued expenses:		
Trade	95,435	129,799
Related parties	78	1,834
Derivative contracts	2,132	958
Total current liabilities	110,642	158,792

Long-term debt	30,136	1,040,630
Derivative contracts		3,052
Other long-term obligations		21,219
Asset retirement obligation	6,979	45,216
Deferred income taxes	13,747	24,922
Total liabilities	161,504	1,293,831
Commitments and contingencies (Note 16)		
Minority interest	8,177	5,092
Redeemable convertible preferred stock, $0.001 par value, 2,650 shares authorized, 2,137 shares issued and outstanding at December 31, 2006		439,643
Stockholders equity:		
Preferred stock, no par; 50,000 shares authorized; no shares issued and outstanding in 2005 and 2006		
Common stock, $0.001 par value, 400,000 shares authorized; 74,332 issued and 72,917 outstanding at 2005 and 93,048 issued and 91,604 outstanding at 2006	73	92
Additional paid-in capital	243,920	574,868
Deferred compensation	(14,885)	
Treasury stock, at cost	(17,335)	(17,835)
Retained earnings	77,229	92,693
Total stockholders equity	289,002	649,818
Total liabilities and stockholders equity	$ 458,683	$ 2,388,384

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

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SandRidge Energy, Inc. and Subsidiaries

Consolidated Statements of Operations

	Years Ended December 31,		
	2004 (Restated)	2005 (Restated)	2006 (Restated)
	(In thousands except per share amounts)		
Revenues:			
Natural gas and crude oil	$ 33,685	$ 49,987	$ 101,252
Drilling and services	39,417	80,343	139,049
Midstream and marketing	98,906	147,133	122,896
Other	3,987	10,230	25,045
Total revenues	175,995	287,693	388,242
Expenses:			
Production	10,230	16,195	35,149
Production taxes	2,497	3,158	4,654
Drilling and services	26,442	52,122	98,436
Midstream and marketing	96,180	141,372	115,076
Depreciation, depletion and amortization natural gas and crude oil	4,909	9,313	26,321
Depreciation, depletion and amortization other	7,765	14,893	29,305
General and administrative	6,554	11,908	55,634
Loss (gain) on derivative contracts	878	4,132	(12,291)
Loss (gain) on sale of assets	(210)	547	(1,023)
Total expenses	155,245	253,640	351,261
Income from operations	20,750	34,053	36,981
Other income (expense):			
Interest income	56	206	1,109
Interest expense	(1,678)	(5,277)	(16,904)
Minority interest	(262)	(737)	(296)
Income (loss) from equity investments	(36)	(384)	967
Total other income (expense)	(1,920)	(6,192)	(15,124)
Income before income tax expense	18,830	27,861	21,857
Income tax expense	6,433	9,968	6,236
Income from continuing operations	12,397	17,893	15,621
Income from discontinued operations (net of tax expense of $232 and $118 in 2004 and 2005, respectively)	451	229	
Income before extraordinary gain	12,848	18,122	15,621

Extraordinary gain on Foreland acquisition	12,544		
Net income	25,392	18,122	15,621
Preferred stock dividends and accretion			3,967
Income available to common stockholders	$ 25,392	$ 18,122	$ 11,654
Basic and Diluted Earnings Per Share:			
Income from continuing operations	$ 0.22	$ 0.31	$ 0.21
Income from discontinued operations, net of income tax	0.01	0.01	
Extraordinary gain on Foreland acquisition	0.22		
Preferred dividends			(0.05)
Basic and diluted income per share available to common stockholders	$ 0.45	$ 0.32	$ 0.16
Weighted average number of shares outstanding:			
Basic	56,312	56,559	73,727
Diluted	56,312	56,737	74,664

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

SandRidge Energy, Inc. and Subsidiaries

Consolidated Statements of Changes in Stockholders Equity

	Preferred Stock	Common Stock	Additional Paid-In Capital	Deferred Compensation	Treasury Stock	Retained Earnings	Total
			(Restated for 2004, 2005 and 2006) (In thousands)				
Balance, January 1, 2004 (previously reported)	$ 23	$ 200	$	$	$	$ 27,628	$ 27,851
Prior period adjustments						6,090	6,090
Balance, January 1, 2004 (restated)	23	200				33,718	33,941
Net income						25,392	25,392
Dividends on preferred stock						(2)	(2)
Balance, December 31, 2004	23	200				59,108	59,331
Exchange of preferred stock for common stock	(23)	1	22				
Purchase of treasury shares		(5)			(17,335)		(17,340)
Stock split (change in par value)		(141)	141				
Issuance of stock in acquisitions		4	55,281				55,285
Stock offering, net of $18.0 million in offering costs		12	173,110				173,122
Restricted shares		2	15,366	(15,366)			2
Amortization of deferred compensation				481			481
Net income						18,122	18,122
Dividends on preferred stock						(1)	(1)
Balance, December 31, 2005		73	243,920	(14,885)	(17,335)	77,229	289,002
Stock offering			3,343				3,343
Change in accounting principle for stock-based compensation			(14,885)	14,885			
Issuance of stock in acquisitions		13	236,271				236,284
Stock offering, net of $3.9 million in offering		6	97,427				97,433

costs							
Stock-based compensation			8,792				8,792
Accretion on redeemable convertible preferred stock						(157)	(157)
Purchase of treasury shares					(500)		(500)
Net income						15,621	15,621
Balance, December 31, 2006	$	$ 92	$ 574,868	$	$ (17,835)	$ 92,693	$ 649,818

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

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SandRidge Energy, Inc. and Subsidiaries

Consolidated Statements of Cash Flows

	Years Ended December 31,		
	2004 (Restated)	2005 (Restated)	2006 (Restated)
	(In thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 25,392	$ 18,122	$ 15,621
Income from discontinued operations, net of tax	451	229	
Income from continuing operations	24,941	17,893	15,621
Adjustments to reconcile net income to net cash provided by operating activities:			
Provision for doubtful accounts	761	33	2,528
Depreciation, depletion and amortization	12,674	24,206	55,626
Debt issuance cost amortization			299
Deferred income taxes	6,433	9,460	348
Extraordinary gain	(12,544)		
Unrealized loss (gain) on derivatives	(1,803)	1,296	1,878
Loss (gain) on sale of assets	(210)	547	(1,023)
Interest income restricted deposits			(151)
Loss (gain) from equity investments, net of distributions	1,066	846	(956)
Stock-based compensation		481	8,792
Minority interests	262	737	296
Changes in operating assets and liabilities increasing (decreasing) cash:			
Receivables	(6,950)	(25,494)	(2,648)
Inventories	(481)	(46)	(938)
Other current assets	(584)	(1,146)	(22,238)
Other assets and liabilities, net	324	775	(2,131)
Accounts payable and accrued expenses	14,569	33,709	12,046
Net cash provided by operating activities by continuing operations	38,458	63,297	67,349
Net cash provided by operating activities by discontinued operations	978	347	
Net cash provided by operating activities	39,436	63,644	67,349
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures for property, plant and equipment	(57,926)	(134,596)	(306,541)
Proceeds from sale of assets	1,443	3,327	19,742
Contributions on equity investments	(1,976)	(1,350)	(3,388)
Acquisitions of assets, net of cash received of $0, $66 and $21,100	(1,169)	(21,247)	(1,054,075)
Proceeds from sale of investments	220	413	2,373
Restricted deposits			(1,051)
Restricted cash		(2,373)	2,373

Net cash used in investing activities for continuing operations	(59,408)	(155,826)	(1,340,567)
Net cash used in investing activities for discontinued operations	(1,931)	(1,473)	
Net cash used in investing activities	(61,339)	(157,299)	(1,340,567)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	41,620	247,460	1,261,910
Repayments of borrowings	(6,840)	(301,285)	(518,870)
Dividends paid-preferred	(2)	(1)	
Minority interests contributions (distributions)	(78)	7,117	(618)
Proceeds from issuance of common stock		173,122	100,776
Proceeds from issuance of redeemable convertible preferred stock			439,486
Purchase of treasury shares			(500)
Debt issuance costs			(15,749)
Net cash provided by financing activities for continuing operations	34,700	126,413	1,266,435
Net cash provided by financing activities for discontinued operations			
Net cash provided by financing activities	34,700	126,413	1,266,435
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	12,797	32,758	(6,783)
CASH AND CASH EQUIVALENTS, beginning of year	176	12,973	45,731
CASH AND CASH EQUIVALENTS, end of year	$ 12,973	$ 45,731	$ 38,948
Supplemental Disclosure of Cash Flow Information:			
Cash paid for interest, net of amounts capitalized	$ 2,024	$ 7,222	$ 15,079
Cash paid for income taxes			1,599
Supplemental Disclosure of Noncash Investing and Financing Activities:			
Common stock issued in connection with acquisitions	$	$ 55,285	$ 236,284
Assumption of restricted deposits and notes payable in connection with acquisition			313,628
Assets disposed in exchange for common stock		17,335	
Insurance premium financed	1,137	2,133	5,023
Accretion on redeemable convertible preferred stock			157

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

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SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements
(Restated)

1. Summary of Significant Accounting Policies

Nature of Business. SandRidge Energy, Inc. and its subsidiaries (formerly known as Riata Energy, Inc.) (collectively, the Company or SandRidge) is an oil and gas company with its principal focus on exploration, development and production related to oil and gas activities. SandRidge also owns and operates drilling rigs and provides related oil field services, midstream gas services operations, and CO_2 and tertiary oil recovery operations. SandRidge s primary exploration, development and production areas are concentrated in West Texas. The Company also operates significant interests in the Cotton Valley Trend in East Texas and Gulf Coast area.

On November 21, 2006, the Company acquired all of the outstanding membership interests of NEG Oil & Gas LLC (NEG) (See Note 3).

Principles of Consolidation. The consolidated financial statements include the accounts of SandRidge Energy, Inc. and its wholly owned or majority owned subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation.

Reclassifications. Certain reclassifications have been made in prior period financial statements to conform with current period presentation.

Restatement. The Company has restated the consolidated financial statements for the year ended December 31, 2006. The restatement relates to the loss (gain) on derivative contracts in the statement of operations. In 2006, the Company recognized an unrealized gain on change in fair value of derivatives related to mark-to-market adjustments of derivative contracts with a counterparty for approximately $3.0 million. The Company recently discovered that the mark-to-market adjustments booked in 2006 for the derivative contracts with this counterparty were recorded incorrectly. As part of its normal closing procedures, the Company requests from the counterparty the Company s mark-to-market position. Historically, the Company s counterparties have sent the statement in terms of SandRidge s position. During the fourth quarter of 2006, the Company entered into derivative contracts with a new counterparty. The new counterparty confirmed to the Company the mark-to-market loss (gain) in their position, not the Company s. The position terms of the statement were not specified on the report and recorded in error during the 2006 year end closing process. As part of the first quarter 2007 closing process, the Company discovered the error.

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SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Restated) (Continued)

The restatement affects Note 12 Derivatives, Note 14 Income Taxes, and Note 21 Industry Segment Information. The restatement had no effect on the Company s previously presented net cash provided by (used in) operating activities, investing activities, or financing activities for any period presented. A comparison of the Company s previously presented deferred tax assets, derivative contracts current assets, derivative contracts non current assets, derivative contracts current liabilities, derivative contracts non current liabilities, deferred tax liabilities, and retained earnings to its restated financial position disclosed herein are as follows (in thousands):

	December 31, 2006 (As originally presented)		December 31, 2006 (As restated)	
Deferred tax assets	$	5,244	$	6,315
Derivative contracts current assets	$	279	$	
Derivative contracts non current assets	$	1,736	$	
Derivative contracts current liabilities	$		$	958
Derivative contracts non current liabilities	$		$	3,052
Deferred tax liabilities	$	26,020	$	24,922
Retained earnings	$	96,549	$	92,693

A comparison of the Company s previously presented net income, income available to common stockholders, and earnings per share to its results of operations disclosed herein are as follows (in thousands, except per share amounts):

	Year Ended December 31,			
	2006 (As originally presented)		2006 (As restated)	
Net income	$	19,477	$	15,621
Income available to common stockholders	$	15,510	$	11,654
Basic and diluted earnings per share available to common stockholders	$	0.21	$	0.16

Change in Method of Accounting for Oil and Gas Operations. In the fourth quarter of 2006, the Company changed from the successful efforts method to the full cost method of accounting for its oil and gas operations. All prior year s financial statements presented herein have been restated to reflect the change.

Management believes that the full cost method is preferable for a company more actively involved in the exploration and development of oil and gas reserves. The full cost method was also utilized by NEG prior to the acquisition, and the assets acquired from NEG constitute more than SandRidge s total oil and gas assets.

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

In accordance with full cost accounting rules, SandRidge is subject to a limitation on capitalized costs. The capitalized cost of oil and gas properties, net of accumulated depreciation, depletion, and amortization,

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Restated) (Continued)

may not exceed the estimated future net cash flows from proved oil and gas reserves discounted at 10%, plus the lower of cost or fair market value of unproved properties as adjusted for related tax effects. If capitalized costs exceed this limit (the ceiling limitation), the excess must be charged to expense. SandRidge did not have any adjustment to earnings due to the ceiling limitation for the periods presented herein.

A comparison of the Company s previously presented property, plant and equipment, net, deferred income taxes and retained earnings under the successful efforts method of accounting to its financial position disclosed herein are as follows (in thousands):

	December 31, 2005 (As originally presented)	December 31, 2005 (As restated)
Property, plant and equipment, net	$ 318,284	$ 337,881
Deferred tax liabilities	$ 6,857	$ 13,747
Retained earnings	$ 64,522	$ 77,229

A comparison of the Company s previously presented income from continuing operations, net income, and earnings per share under the successful efforts method of accounting to its results of operations disclosed herein are as follows (in thousands, except per share amounts):

	Year Ended December 31,	
	2004	2005
Income from continuing operations, as originally presented	$ 8,327	$ 15,346
Net income, as originally presented	$ 21,322	$ 15,575
Basic and diluted earnings per share, as originally presented	$ 0.38	$ 0.28
Income from continuing operations, as restated	$ 12,397	$ 17,893
Net income, as restated	$ 25,392	$ 18,122
Basic and diluted earnings per share, as restated	$ 0.45	$ 0.32

Use of Estimates. The preparation of the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Estimates of oil and natural gas reserves and their values, future production rates and future costs and expenses are inherently uncertain for numerous reasons, including many factors beyond the Company s control. Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of data available and of engineering and geological interpretation and judgment. In addition, estimates of reserves may be revised based on actual production, results of subsequent exploitation and development activities, prevailing commodity prices, operating cost and other factors. These revisions may be material and could materially affect the Company s future depletion, depreciation and amortization expenses.

The Company s revenue, profitability, and future growth are substantially dependent upon the prevailing and future prices for oil and natural gas, which are dependent upon numerous factors beyond its control such as economic, regulatory developments and competition from other energy sources. The energy markets have

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Restated) (Continued)

historically been volatile and there can be no assurance that oil and natural gas prices will not be subject to wide fluctuations in the future. A substantial or extended decline in oil and natural gas prices could have a material adverse effect on the Company s financial position, results of operations, cash flows and quantities of oil and natural gas reserves that may be economically produced.

Cash and Cash Equivalents. The Company considers all highly-liquid instruments with a maturity of three months or less when purchased to be cash equivalents. Those securities are readily convertible to known amounts of cash and bear insignificant risk of changes in value due to their short maturity period.

Restricted Cash. Restricted cash of approximately $2.4 million at December 31, 2005 was pledged as collateral on certain bank debt and is classified as restricted cash on the consolidated balance sheets. The restriction was released in April 2006.

Accounts Receivable, net. The Company has receivables for sales of oil, gas and natural gas liquids, as well as receivables related to the exploration and extraction services for oil, gas and natural gas liquids. Management has established an allowance for doubtful accounts. The allowance is evaluated by management and is based on management s periodic review of the collectibility of the receivables in light of historical experience, the nature and volume of the receivables, and other subjective factors.

Inventories. Inventories consist of oil field services supplies and are stated at the lower of cost or market with cost determined on an average cost basis.

Goodwill. Goodwill represents the amount by which the total purchase price SandRidge has paid to acquire businesses accounted for as purchases exceeds the estimated fair value of the net assets acquired. The Company tests goodwill for impairment annually and charges income for any impairment recognized, but goodwill is not otherwise amortized.

Debt Issue Costs. The Company amortizes debt issue costs related to its senior credit facility and senior bridge facility as interest expense over the scheduled maturity period of the debt. Unamortized debt issuance costs were $0 as of December 31, 2005 and approximately $15.5 million as of December 31, 2006. The Company includes those unamortized costs in other assets.

Revenue Recognition and Gas Balancing. Oil and natural gas revenues are recorded when title passes to the customer, net of royalties, discounts and allowances, as applicable. The Company accounts for oil and natural gas production imbalances using the sales method, whereby the Company recognizes revenue on all oil and natural gas sold to its customers notwithstanding the fact that its ownership may be less than 100% of the oil and natural gas sold. Liabilities are recorded by the Company for imbalances greater than the Company s proportionate share of remaining estimated oil and natural gas reserves. The Company did not have significant gas imbalance positions at December 31, 2005. The Company has recorded a liability for gas imbalance positions related to gas properties with insufficient proved reserves of $0.9 million at December 31, 2006. The Company includes the gas imbalance positions in other long-term obligations.

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

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

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Restated) (Continued)

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

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

Environmental Costs. Environmental expenditures are expensed or capitalized, as appropriate, depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and that do not have future economic benefit, are expensed. Liabilities related to future costs are recorded on an undiscounted basis when environmental assessments and/or remediation activities are probable and costs can be reasonably estimated. Environmental costs accrued at December 31, 2005 and 2006 were not material.

Oil and Natural Gas Operations. The Company uses the full cost method to account for its natural gas and oil properties. Under full cost accounting, all costs directly associated with the acquisition, exploration and development of natural gas and oil reserves are capitalized into a full cost pool. These capitalized costs include costs of all unproved properties, internal costs directly related to the Company s acquisition, exploration and development activities and capitalized interest. These costs are amortized using a unit-of-production method. Under this method, the provision for depreciation, depletion and amortization is computed at the end of each quarter by multiplying total production for such quarter by a depletion rate. The depletion rate is determined by dividing the total unamortized cost base by net equivalent proved reserves at the beginning of the quarter.

Costs associated with unproved properties are excluded from the total unamortized cost base until a determination has been made as to the existence of proved reserves. Unproved properties are reviewed at the end of each quarter to determine whether the costs incurred should be reclassified to the full cost pool and, thereby, subject to amortization. Sales and abandonments of natural gas and oil properties being amortized are accounted for as adjustments to the full cost pool, with no gain or loss recognized, unless the adjustments would significantly alter the relationship between capitalized costs and proved natural gas and oil reserves. A significant alteration would not ordinarily be expected to occur upon the sale of reserves involving less than 25% of the reserve quantities of a cost center.

Under full cost accounting, total capitalized costs (net of accumulated depreciation, depletion and amortization) less related deferred taxes may not exceed an amount equal to the present value of future net revenues from proved reserves, discounted at 10% per annum, plus the lower of cost or fair value of unevaluated properties, plus estimated salvage value, less income tax effects (the ceiling limitation). A ceiling limitation calculation is performed at the end of each quarter. If total capitalized costs (net of accumulated depreciation, depletion and amortization) less related deferred taxes are greater than the ceiling limitation, a write-down or impairment of the full cost pool is required. A write-down of the carrying value of the full cost pool is a non-cash charge that reduces earnings and impacts stockholders equity in the period of occurrence and typically results in lower depreciation, depletion and amortization expense in future periods. Once incurred, a write-down is not reversible at a later date.

The ceiling test is calculated using natural gas and oil prices in effect as of the balance sheet date, as adjusted for basis or location differentials as of the balance sheet date and held constant over the life of the reserves (net wellhead prices). If applicable, these net wellhead prices would be further adjusted to include the effects of any fixed price arrangements for the sale of natural gas and oil. The Company may, from time-

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Restated) (Continued)

to-time, use derivative financial instruments to hedge against the volatility of natural gas prices. Derivative contracts that qualify and are designated as cash flow hedges and, are included in estimated future cash flows. Historically, the Company has not designated any of its derivative contracts as cash flow hedges. In addition, the future cash outflows associated with future development wells are included in the computation of the discounted present value of future net revenues for the purposes of the ceiling test calculation.

The costs associated with unproved properties are not initially included in the amortization base and relate to unproved leasehold acreage, wells and production facilities in progress and wells pending determination of the existence of proved reserves, together with capitalized interest costs for these projects. Unproved leasehold costs are transferred to the amortization base with the costs of drilling the related well once a determination of the existence of proved reserves has been made or upon impairment of a lease. Costs of seismic data are allocated to various unproved leaseholds and transferred to the amortization base with the associated leasehold costs on a specific project basis. Costs associated with wells in progress and completed wells that have yet to be evaluated are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property. Costs of dry holes are transferred to the amortization base immediately upon determination that the well is unsuccessful. The Company capitalized exploration expense of $3.7 million in 2004, $2.1 million in 2005 and $13.7 million in 2006.

All items classified as unproved property are assessed on a quarterly basis for possible impairment or reduction in value. Properties are assessed on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

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

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

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

Investments. Investments in affiliated companies are accounted for under the cost or equity method, based on the Company s ability to exercise significant influence.

Asset Retirement Obligation. The Company owns oil and natural gas properties which require expenditures to plug and abandon the wells when the oil and natural gas reserves in the wells are depleted. These expenditures are recorded in the period in which the liability is incurred (at the time the wells are drilled or acquired). Asset retirement obligations are recorded as a liability at their estimated present value at the asset s

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Restated) (Continued)

inception, with the offsetting charge to property cost. Periodic accretion expense of the estimated liability is recorded in the statement of operations.

The asset retirement obligations primarily represent the Company s estimate of fair value to plug, abandon and remediate the oil and natural gas properties at the end of their productive lives, in accordance with applicable state laws. The Company has determined the asset retirement obligations by calculating the present value of estimated expenses related to the liability. Estimating the future asset retirement obligations requires management to make estimates and judgments regarding timing, existence of a liability, and what constitutes adequate restoration. Inherent in the present value calculation rates, are the timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligations liability, a corresponding adjustment is made to the related asset. The following is a reconciliation of the asset retirement obligation for the years ended December 31, (in thousands).

	2004	2005	2006
Asset retirement obligation, January 1	$ 3,883	$ 4,394	$ 6,979
Liability incurred upon acquiring and drilling wells	372	2,779	2,996
NEG acquisition			40,343
Revisions in estimated cash flows			(5,700)
Liability settled in current period		(512)	
Accretion of discount expense	139	318	598
Asset retirement obligation, December 31	$ 4,394	$ 6,979	$ 45,216

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

Minority Interest. As of December 31, 2006, minority interest in the Company s consolidated subsidiaries consisted of the following:

the 15.00% interest in Integra Energy;

the 30.38% interest in Sagebrush Pipeline; and

the 46.71% interest in Cholla Pipeline.

Concentration of Risk. The Company maintains cash balances at several banks. Accounts at each institution are insured by the Federal Deposit Insurance Corporation up to $100,000. From time to time, the Company may have balances in these accounts that exceed the federally insured limit. The Company does not anticipate any loss associated with balances in excess of the federally insured limit.

Fair Value of Financial Instruments. For certain of the Company s financial instruments, including cash, accounts receivable and accounts payable, the carrying value approximates fair value because of their short maturity. The carrying value of borrowings under the senior credit facility and the notes payable approximates fair value because their interest rates are based on fair value indexes. The fair value of the Company s senior bridge facility and convertible preferred stock approximate book value based on current material transactions completed by the Company subsequent to year end.

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SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Restated) (Continued)

Derivative Financial Instruments. To manage risks related to increases in interest rates and changes in oil and gas prices, the Company occasionally enters into interest rate swaps and oil and gas futures contracts.

The Company recognizes all of its derivative instruments as either assets or liabilities at fair value. The accounting for changes in the fair value (i.e., gains or losses) of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship, and further, on the type of hedging relationship. For those derivative instruments that are designated and qualify as hedging instruments, the Company designates the hedging instrument, based on the exposure being hedged, as either a fair value hedge or a cash flow hedge. For derivative instruments not designated as hedging instruments, the gain or loss is recognized in current earnings during the period of change. None of the Company s derivatives were designated as hedging instruments during 2004, 2005 and 2006.

Stock-Based Compensation. Effective January 1, 2006, the Company adopted SFAS No. 123-R, Share-Based Payment (SFAS 123R). SFAS 123R establishes the accounting for equity instruments exchanged for employee services. Under SFAS 123R, share-based compensation cost is measured at the grant date based on the calculated fair value of the award. The expense is recognized over the employees requisite service period, generally the vesting period of the award. SFAS 123R also requires the related excess tax benefit received upon exercise of stock options or vesting of restricted stock, if any, to be reflected in the statement of cash flows as a financing activity rather than an operating activity. The Company does not have any excess tax benefits.

Recent Accounting Pronouncements. In July 2006, the Financial Accounting Standards Board (FASB) issued FIN 48, Accounting for Uncertainty in Income Taxes, or FIN 48, which is effective for the Company as of the interim reporting period beginning January 1, 2007. The validity of any tax position is a matter of tax law, and generally there is no controversy about recognizing the benefit of a tax position in a company s financial statements when the degree of confidence is high that the tax position will be sustained upon examination by a taxing authority. The tax law is subject to varied interpretation, and whether a tax position will ultimately be sustained may be uncertain. Under FIN 48, the impact of an uncertain income tax position on the income tax provision must be recognized at the largest amount that is more likely than not to be sustained upon audit by the relevant taxing authority. A benefit based on an uncertain income tax position will not be recognized if it has less than a 50% likelihood of being sustained. FIN 48 also requires additional disclosures about unrecognized tax benefits associated with uncertain income tax positions and a reconciliation of the change in the unrecognized benefit. In addition, FIN 48 requires interest to be recognized on the full amount of deferred benefits for uncertain tax positions. An income tax penalty is recognized as expense when the tax position does not meet the minimum statutory threshold to avoid the imposition of a penalty. The Company continues to evaluate the impact of FIN 48 on the consolidated financial statements. At this time, the Company is evaluating the impact of FIN 48.

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

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option For Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115 (SFAS No. 159), which permits an entity to choose to measure certain financial assets and liabilities at fair value. SFAS No. 159 also revises provisions of SFAS No. 115 that apply to available-for-sale and trading securities. This statement is

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Restated) (Continued)

effective for fiscal years beginning after November 15, 2007. The Company has not yet evaluated the potential impact of this standard.

2. Goodwill

In accordance with SFAS No. 142, Goodwill and Other Intangible Assets, the Company performs an annual impairment test (or more frequently if impairment indicators arise) for goodwill and other intangibles with indefinite lives. The Company allocates goodwill to various reporting units to perform its impairment test. SFAS No. 142 requires that the implied fair value of the reporting unit be compared with its carrying amount on an annual basis to determine if there is a potential impairment. If the fair value of the reporting unit is less than its carrying value, the Company would record an impairment loss to the extent of that difference. The Company bases the fair values of its reporting units on a combination of valuation approaches, including discounted cash flows, multiples of sales and earnings before interest, taxes, depreciation, depletion and amortization and comparisons of recent transactions. In the fourth quarter of 2006, the Company conducted its annual valuation test and determined it was not required to recognize any goodwill impairment. As of December 31, 2005, the Company had no intangible assets and goodwill. As of December 31, 2006, the Company had no intangible assets.

The change in the carrying amount of goodwill for 2006 was as follows (in thousands):

	2006
Balance at January 1, 2006	$
Acquisition	26,198
Balance at December 31, 2006	$ 26,198

3. Acquisitions and Dispositions

2005 Acquisitions

The Company closed the following acquisitions in 2005:

The acquisition of additional equity interests in PetroSource, which increased the Company s ownership from 22.4% to 86.5%, resulting in the consolidation of PetroSource in the Company s financial statements;

The acquisition from an executive officer and director of the remaining 50% equity interest in the Company s compression services subsidiary, Larco, resulting in it becoming a wholly-owned subsidiary;

The acquisition from an executive officer and director of approximately 7,400 net acres of additional leasehold interest in West Texas in properties in which the Company previously held interests;

The acquisition of approximately 2,503 net acres of additional leasehold interest in property in the Piceance Basin in which the Company previously held interests;

The acquisition from a director of additional working interests in Missouri and Nevada leases in which the Company previously held interests;

The acquisition of an additional 19.5% before pay-out interest in the Company s subsidiary, Sagebrush Pipeline LLC; and

The acquisition of certain interests in several oil and natural gas properties in West Texas from Carl E. Gungoll Exploration, LLC and certain other parties. The purchase price was approximately $8.0 million, comprised of $5.4 million in cash, and 174,833 shares of common stock (valued at $2.6 million).

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Notes to Consolidated Financial Statements (Restated) (Continued)

The acquisitions were financed with approximately $21.3 million in cash and the issuance of 3,685,690 shares of common stock with an aggregate value of approximately $55.3 million. Details are set forth below for each of the acquisition transactions (in thousands):

					Consideration Paid		
Acquisition Transaction	Addition to Property, Plant & Equipment	Addition to Net Assets(1)	Elimination of Investments	Change in Minority Interest	Common Stock No. of Shares	Common Stock at $15/Share	Cash, Net of Cash Acquired
PetroSource additional interests	$ 73,744	$ (37,381)	$ (3,052)	$ 3,253	958	$ 14,372	$ 15,686
Piceance Basin additional interests	17,565				1,164	17,456	109
West Texas additional lease interests	10,000				667	10,000	
Larco remaining interest	5,054			(2,446)	500	7,500	
Gungoll lease interests	8,074				176	2,622	5,452
Various additional lease interests	268				17	268	
Sagebrush additional interests	689			(2,378)	204	3,067	
Totals	$ 115,394	$ (37,381)	$ (3,052)	$ (1,571)	3,686	$ 55,285	$ 21,247

(1) The purchase price for additional interests in PetroSource was approximately $30.1 million, comprised of $15.7 million in cash (net of $0.1 million in cash acquired), and approximately 958,000 shares of SandRidge common stock (valued at $14.4 million). The purchase price has been allocated to accounts receivable of $4.5 million, other current assets of $0.1 million, other assets of $0.4 million, accounts payable and accrued expenses of $2.6 million, long-term debt of $37.4 million, and asset retirement obligations of $2.4 million in the accompanying consolidated balance sheet as of December 31, 2005.

The Company completed its purchase accounting allocations for the 2005 acquisitions in 2006 and recorded an additional $3.8 million deferred tax liability related to the Larco stock acquisition.

2006 Acquisitions and Dispositions

The Company closed the following acquisitions and dispositions in 2006:

On March 15, 2006, the Company acquired from an executive officer and director, an additional 12.5% interest in PetroSource Energy Company, a consolidated subsidiary. The acquisition consisted of the retirement of subordinated debt of approximately $1.0 million and a $4.5 million cash payment for the ownership interest acquired for a total acquisition price of approximately $5.5 million.

On May 1, 2006, the Company purchased certain leases in developed and undeveloped properties from an oil and gas company. The purchase price was approximately $40.9 million in cash. The cash consideration was paid in July 2006.

On May 26, 2006, the Company purchased several oil and natural gas properties from an oil and gas company. The purchase price was approximately $12.9 million, comprised of $8.2 million in cash, and 251,351 shares of SandRidge Energy, Inc. common stock (valued at $4.7 million). The cash and equity consideration was paid in July 2006.

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On June 1, 2006, the Company purchased certain producing well interest from an executive officer and director. The purchase price was approximately $9.0 million in cash. The cash consideration was paid in July 2006.

On June 7, 2006, the Company acquired subordinated debt plus accrued interest of approximately $0.1 million and the remaining 1% interest in PetroSource Energy Company, a consolidated subsidiary, from an oil and gas company. The purchase price was 27,749 shares of SandRidge Energy, Inc. common stock (valued at $0.5 million). The Company now owns 100% of PetroSource Energy Company.

The preceding 2006 acquisitions were financed with approximately $63.7 million in cash and the issuance of 279,100 shares of common stock with an aggregate value of approximately $5.1 million. Details are set forth below for each of the acquisition transactions (in thousands):

				Consideration Paid		
Acquisition Transaction	**Addition to Property, Plant & Equipment**	**Change in Minority Interest**	**Retirement of Subordinated Debt(1)**	**Common Stock No. of Shares**	**Common Stock**	**Cash**
PetroSource additional interests March 15, 2006	$ 2,116	$ (2,370)	$ (1,003)		$	$ 5,489
Purchased leases May 1, 2006	40,960					40,960
Oil and natural gas properties May 26, 2006	12,850			251	4,650	8,200
Producing well interest from an executive officer and director June 1, 2006	9,000					9,000
PetroSource additional interest (remaining 1% interest) June 7, 2006	85	(393)		28	478	
Totals	$ 65,011	$ (2,763)	$ (1,003)	279	$ 5,128	$ 63,649

(1) Includes retirement of subordinated debt of $972,000 and accrued interest of $31,000.

In July 2006, the Company sold leaseholds and lease and well equipment for $16.0 million. The book basis of the assets at the time of the sale transaction was $3.7 million. The sale was accounted for as an adjustment to the full cost pool, with no gain recognized.

In August 2006, the Company sold certain assets (Stockton Plaza, Authentix Investment and certain other assets) to the Company s former President and Chief Operating Officer, N. Malone Mitchell, 3rd, for approximately $6.1 million in cash. These investments had been accounted for under the cost method and reflected as investments in the consolidated balance sheet as of December 31, 2005. The sale transaction resulted in a $0.8 million gain recognized in earnings by the Company in August 2006. The gain is included in loss (gain) on sale of assets in the consolidated statements of operations.

On November 21, 2006, the Company acquired all of the outstanding membership interests of NEG for approximately $990.4 million in cash, the assumption of $300 million in debt, the receipt of cash of $21.1 million, and the issuance of 12,842,000 shares of SandRidge Energy, Inc. common stock (valued at approximately $231.2 million). NEG owned core assets in the Val Verde and Permian Basins of West Texas, including overlapping or contiguous interests in the properties that the Company owns in the West Texas Overthrust. To finance the NEG acquisition, the Company entered into a new $750 million senior secured credit facility and an $850 million senior unsecured bridge loan facility. The Company also issued $550 million of redeemable convertible preferred stock and common units (consisting of

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Notes to Consolidated Financial Statements (Restated) (Continued)

shares of common stock and a warrant to purchase convertible preferred stock upon the surrender of the common stock) in a private placement to certain eligible purchasers.

The accompanying balance sheet at December 31, 2006 includes the allocations of the purchase price for the NEG acquisition. The allocation of the purchase price to specific assets and liabilities were based, in part, upon an appraisal of the fair value of NEG assets. The Company continues to obtain information to refine the fair value of the assets acquired and the liabilities assumed. The Company expects that a final allocation of the purchase price will be completed in fiscal year 2007.

The following table presents the NEG acquisition purchase price allocation, including professional fees and other related acquisition costs, to the net assets acquired and liabilities assumed, based on the fair values with the balance of the purchase price, $26.2 million, included in goodwill at the acquisition date (in thousands):

Cash and cash equivalents	$ 21,100
Accounts receivable	30,840
Other current assets	6,025
Property, plant and equipment	1,497,874
Goodwill	26,198
Restricted deposits	31,987
Other assets	270
Total assets acquired	1,614,294
Accounts payable and other current liabilities	46,082
Deferred income taxes	2,189
Long-term debt	281,641
Other long-term obligations	1,357
Asset retirement obligation	40,343
Net assets acquired	1,242,682
Less: Cash and cash equivalents acquired	(21,100)
Net amount paid for acquisition	$ 1,221,582

The Company has assigned all of the NEG goodwill to the Exploration and Production segment. Goodwill in the amount of $24.0 million is deductible for tax purposes.

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Restated) (Continued)

Pro Forma Information

The unaudited financial information in the table below summarizes the combined results of operations of SandRidge and NEG, on a pro forma basis, as though the companies had been combined as of January 1, 2005. The pro forma financial information is presented for informational purposes only and is not indicative of the results of operations that would have been achieved if the acquisition had taken place on January 1, 2005 or of results that may occur in the future. The pro forma adjustments include estimates and assumptions based on currently available information. The Company believes the estimates and assumptions are reasonable, and the significant effects of the transactions are properly reflected. However, actual results may differ materially from this pro forma financial information. The following table presents the actual results for the years ended December 31, 2005 and 2006 and the respective unaudited pro forma information to reflect the NEG acquisition (in thousands, except per share amounts):

	Year Ended December 31,			
	2005		2006	
	Actual	Pro Forma	Actual	Pro Forma
Revenues	$ 287,693	$ 560,235	$ 388,242	$ 565,256
Income (loss) from continuing operations	17,893	(49,594)	15,621	36,337
Net income (loss)	18,122	(49,594)	15,621	36,337
Basic and diluted earnings per share available (applicable) to common stockholders:				
Income (loss) from continuing operations	$ 0.31	$ (0.96)	$ 0.21	$ 0.40
Net income (loss) available to common stockholders	$ 0.32	$ (0.96)	$ 0.16	$ 0.04

4. Discontinued Operations

On September 30, 2005, the Company exchanged substantially all of its land and agriculture operations with its majority stockholder. The majority stockholder exchanged 1,414,849 shares of the Company s common stock for these operations. The shares were exchanged at their historical basis and the exchange was reflected as a treasury share transaction. The net book value of assets exchanged were $23.6 million. There was no gain (loss) recognized in this transaction. The land and agriculture operations are presented as discontinued operations, net of income taxes in the consolidated statements of operations.

The following table summarizes net revenue and net income (loss) from discontinued operations for the years ended December 31, 2004, 2005 and 2006 (in thousands):

	2004	2005	2006
Revenues	$ 1,968	$ 1,683	$
Operating expenses	(1,285)	(1,336)	

Income from discontinued operations		683		347	
Income tax expense		(232)		(118)	
Net income from discontinued operations	$	451	$	229	$

No assets were classified as held for sale at December 31, 2005 or 2006.

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SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Restated) (Continued)

5. Accounts Receivable

A summary of accounts receivable is as follows (in thousands):

	December 31, 2005	December 31, 2006
Oil and gas service	$ 12,809	$ 8,489
Oil and gas sales	29,113	57,458
Joint interest billing	18,109	26,553
Other		299
	60,031	92,799
Less allowance for doubtful accounts	(851)	(3,025)
Total accounts receivable, net	$ 59,180	$ 89,774

The following tables show the balance in the allowance for doubtful accounts and activity for the years ended December 31, 2004, 2005 and 2006 (in thousands).

Allowance for Doubtful Accounts	**Balance at Beginning of Period**	**Additions Charged to Costs and Expenses**	**Deductions(1)**	**Balance at End of Period**
Year ended December 31, 2004	$ 602	$ 761	$ (289)	$ 1,074
Year ended December 31, 2005	$ 1,074	$ 33	$ (256)	$ 851
Year ended December 31, 2006	$ 851	$ 2,528	$ (354)	$ 3,025

(1) Deductions represent the write-off/recovery of receivables.

6. Other Current Assets

Other current assets consist of the following (in thousands):

	December 31, 2005	December 31, 2006

Prepaid insurance	$ 2,369	$ 7,604
Prepaid drilling	407	2,207
Materials and supplies	83	6,244
Post closing receivable NEG acquisition		15,232
Other	385	207
Total other current assets	$ 3,244	$ 31,494

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7. Property, Plant and Equipment

Property, plant and equipment consists of the following (in thousands):

	December 31, 2005 (Restated)	December 31, 2006
Oil and natural gas properties:		
Proved	$ 160,789	$ 1,636,832
Unproved	33,974	282,374
Total oil and natural gas properties	194,763	1,919,206
Less accumulated depreciation and depletion	(35,029)	(60,752)
Net oil and natural gas properties capitalized costs	159,734	1,858,454
Land	852	738
Non oil and gas equipment	210,380	337,294
Buildings and structures	4,708	6,564
Construction in progress	267	
Total	216,207	344,596
Less accumulated depreciation, depletion and amortization	(38,060)	(68,332)
Net capitalized costs	178,147	276,264
Total property, plant and equipment	$ 337,881	$ 2,134,718

The amount of capitalized interest in 2006 was approximately $1.4 million and is included in the above non oil and gas equipment balance. The Company did not capitalize any interest in 2004 or 2005.

Costs Excluded

Costs associated with unproved properties related to continuing operations of $282.4 million as of December 31, 2006 are excluded from amounts subject to amortization. The majority of the evaluation activities are expected to be completed within a four-year period. In addition, the Company s internal engineers evaluate all properties on an annual basis. The average composite rates used for depreciation, depletion and amortization were $0.69 per Mcfe in 2004, $1.23 per Mcfe in 2005 and $1.68 per Mcfe in 2006.

Costs Excluded by Year Incurred (in thousands)

	Prior Years	2004	2005	2006	Excluded Costs at December 31, 2006
		Year Cost Incurred			
Property acquisition	$	$	$	$ 251,839	$ 251,839
Exploration				30,535	30,535
Development					&nbs