SANDRIDGE ENERGY INC
Form 10-K
March 07, 2008

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

Form 10-K

(Mark One)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2007

OR

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission File Number: 1-33784

SANDRIDGE ENERGY, INC.
(Exact name of registrant as specified in its charter)

Delaware	**20-8084793**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
1601 N.W. Expressway, Suite 1600, Oklahoma City, Oklahoma	**73118**
(Address of principal executive offices)	*(Zip Code)*

(405) 753-5500
(Registrant s telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $0.001 par value	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes o No þ

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No þ

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act (Check one):

Large accelerated filer o	Accelerated filer o	Non-accelerated filer þ (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Exchange Act Rule 12b-2). Yes o No þ

The initial public offering of SandRidge Energy, Inc. s common stock, par value of $0.001, commenced trading on November 6, 2007. Prior to that date, there was no public market for the registrant s common stock. At February 28, 2008 there were 142,718,362 shares of our common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE
(To The Extent Indicated Herein)

Portions of the proxy statement for the 2008 Annual Meeting of Shareholders are incorporated by reference in Part III.

SANDRIDGE ENERGY, INC.

2007 ANNUAL REPORT ON FORM 10-K

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PART I

Items 1 and 2. ***Business and Properties***

General

SandRidge Energy, Inc. is an independent natural gas and oil company headquartered in Oklahoma City, Oklahoma with our principal focus on exploration, development and production activities. We also own and operate drilling rigs and a related oil field services company operating under the name Lariat Services, Inc. ; gas gathering, marketing and processing facilities; and, through our wholly-owned subsidiary PetroSource Energy Company, CO_2 treating and transportation facilities and tertiary oil recovery operations. We were originally organized in the State of Texas in 1984 under a predecessor company name and in 2006, we reorganized as a Delaware corporation and adopted the SandRidge Energy, Inc. name.

We are focused on expanding the 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. The WTO includes the Piñon Field, the South Sabino prospect, the Big Canyon prospect and other prospects that we are currently evaluating. 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. 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, Oklahoma and the Piceance Basin of Colorado.

We have assembled an extensive natural gas and oil property base in which we have identified approximately 4,600 potential drilling locations, including approximately 2,600 in the WTO. As of December 31, 2007, our proved reserves were 1,516.2 Bcfe, of which 86% were natural gas. We had 1,654 gross (1,234 net) producing wells, substantially all of which we operate. As of December 31, 2007, we had interests in approximately 1,303,107 gross (822,287 net) natural gas and oil leased acres. We had 30 rigs drilling in the WTO, six rigs drilling in East Texas, two rigs drilling in Oklahoma, and two rigs drilling in other areas as of December 31, 2007.

We also operate businesses that are complementary to our primary exploration, development and production activities, which provides us with operational flexibility and an advantageous cost structure. We own a fleet of 32 drilling rigs, three of which are currently being retrofitted. In addition, we are a 50% partner in a limited partnership that owns an additional twelve rigs, eleven of which are currently operational. 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.

In November 2007, we completed the initial public offering of our common stock and received net proceeds of $794.7 million. We used the proceeds to repay indebtedness outstanding under our senior credit facility, repay a note related to a recent acquisition and fund a portion of our 2007 and 2008 capital expenditure programs.

Our capital expenditures and acquisitions for 2007 of approximately $1,397.4 million included $1,150.6 million for exploration and development (including land and seismic acquisitions and our tertiary recovery operations), $123.2 million for drilling and oil field services, $73.8 million for our midstream operations and $49.8 million for other capital expenditures. Approximately $871.2 million of our 2007 capital expenditures was spent on our Piñon

Field development and our exploratory projects in the WTO (including land and seismic acquisitions). We drilled approximately 316 gross (274.7 net) wells in 2007, including approximately 190 gross (177.8 net) wells in the WTO.

On November 21, 2006, we acquired all of the outstanding membership interests in NEG Oil & Gas LLC (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 dramatically increased our exploration and production segment operations. The NEG acquisition, coupled with numerous acquisitions of additional working interests completed during 2007, 2006 and late 2005, have significantly increased our holdings in the WTO.

Our principal executive offices are located at 1601 N.W. Expressway, Suite 1600, Oklahoma City, Oklahoma 73118 and our telephone number is (405) 753-5500. We make available free of charge on our website at *www.sandridgeenergy.com* our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission. Any materials that we have filed with the SEC may be read and copied at the SEC s Public Reference Room at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an internet site that contains reports, proxy and information statements, and other information regarding us. The SEC s website address is *www.sec.gov*.

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References to SandRidge , us , we , Company and our in this report refer to SandRidge Energy, Inc. together with subsidiaries. PetroSource refers to our wholly-owned subsidiary, PetroSource Energy Company and Lariat refers to our wholly-owned subsidiary, Lariat Services, Inc.

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 Drilling and Development of Existing Acreage. We expect to generate long-term reserve and production growth by exploring and drilling and developing our large acreage position. Our primary exploration and development focus will be in the WTO, where we have identified approximately 2,600 potential drilling locations and had 30 rigs operating as of December 31, 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 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 effectively develop our own acreage while maintaining the flexibility of a third-party contract drilling business. By controlling our fleet of drilling rigs and gathering and treating assets, we believe we will be able to better control overall costs and maintain a high degree of operational flexibility.

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

Competitive Strengths

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

Large Asset Base with Substantial Drilling Inventory. Our producing properties are characterized by long-lived predominantly natural gas reserves with established production profiles. Our estimated proved reserves of 1,516.2 Bcfe as of December 31, 2007 had a proved reserves to production ratio of approximately 17.7 years. Our core area of operations in the WTO has expanded to 600,546 gross (508,745 net) acres as of December 31, 2007. We have identified approximately 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 Energy Corporation, purchased a significant interest in us and became our Chairman and Chief Executive Officer. Mr. Ward leads an experienced management team of 11 executive officers and 38 senior executives. Our management team averages over 24 years of experience working in or servicing the natural gas and oil industry. Our management team, board of directors and employees owned 37.2% of our capital stock as of December 31, 2007, which we believe aligns their objectives with those of our stockholders.

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High Degree of Operational Control. We operate over 99.2% of our production in the WTO, East Texas and the Gulf Coast area, which permits us to manage our operating costs and better control capital expenditures and the timing of development and exploitation activities.

Large Modern Fleet of Drilling Rigs. We own a fleet of 32 drilling rigs, three of which are currently being retrofitted. In addition, we are a 50% partner in a limited partnership that owns an additional twelve rigs, eleven of which are operational. By controlling a large, modern and efficient drilling fleet, we can develop our existing reserves and explore for new reserves on a more economical 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 December 31, 2007 unless otherwise noted:

	Estimated Net Proved Reserves (Bcfe)	PV-10 (in millions)(1)	Daily Production (Mmcfe/d)(2)	Proved Reserves/ Production (Years)	Gross Acreage	Net Acreage	Number of Identified Potential Drilling Locations
Area							
WTO	922.2	1,785.5	115.7	21.8	600,546	508,745	2,594
East Texas	202.5	331.1	32.7	17.0	53,388	32,739	540
Gulf Coast	97.8	388.3	42.5	6.3	50,768	33,317	42
Other:							
Gulf of Mexico	60.1	240.3	18.3	9.0	73,614	36,770	66
Other West Texas	38.0	192.6	12.1	8.6	31,847	22,941	77
Tertiary recovery- West Texas (PetroSource)	119.7	468.3	0.8	410.0	9,064	8,195	67
Piceance Basin	9.0	8.9	0.6	41.0	40,334	15,686	828
Other, including Oklahoma	66.9	135.5	11.8	15.5	443,546	163,894	380
Total	1,516.2	3,550.5	234.5	17.7	1,303,107	822,287	4,594

(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, 2007, see Proved Reserves. Our Standardized Measure was $2,718.5 million at December 31, 2007.

(2) Average daily net production for the month of December 2007 was 235 Mmcfe/d.

West Texas Overthrust (WTO)

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

The primary reservoir rocks in the WTO range in depth from 2,000 to 11,000 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. 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 a three-year, multi-phase seismic program to acquire 1,400 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 exploratory drilling risk and improving completion efficiency. The first two phases of the seismic program covered 389 square miles and were completed during 2007.

We have acquired leasehold acreage in the WTO, tripling our position since January 2006. As of December 31, 2007 we owned 600,546 gross (508,745 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 61% of our proved reserve base as of December 31, 2007 and approximately 76% of our 2007 exploration and development expenditures (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 December 31, 2007, our estimated proved natural gas and oil reserves in the Piñon Field were 922.2 Bcfe, 55% of which were proved undeveloped reserves. This field has produced more than 266.2 Bcfe through December 31, 2007 and currently produces in excess of 115 net Mmcfe per day.

Our interests in the Piñon Field include 471 producing wells as of December 31, 2007. We had a 93% average working interest in the producing area of Piñon Field and were running 30 drilling rigs in the Piñon Field as of December 31, 2007. We drilled 190 wells in the field during 2007. As of December 31, 2007, we have identified approximately 2,600 potential well locations in the Piñon Field, including approximately 400 proved undeveloped drilling locations.

West Texas Overthrust Prospects. Through our regional exploratory efforts, to date we have identified several exploratory prospect areas in the WTO:

> *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. Results from our first phase of 3-D seismic in this area in 2007 are encouraging and we plan to drill up to seven wells in the South Sabino Prospect in 2008.
>
> *Big Canyon Prospect Area.* Located approximately 25 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. Our 3-D seismic survey over the Big Canyon prospect area was acquired in late 2007. Exploratory wells are planned in 2008 to further evaluate both the Tesnus and the Caballos in a location structurally updip to the Big Canyon Ranch 106-1 well.
>
> *Other Prospect Areas.* We have identified several other potential prospect areas in the WTO that we are currently evaluating.

West Texas Overthrust Development. The following table provides information concerning development opportunities 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 2008 Drilling Locations	2008 Capital Expenditures Budget (In millions)(2)	2007 Year End Rigs Working
509.9	731.6	397	2,594	267	622	30

(1) As of December 31, 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 53,388 gross (32,739 net) acres in East Texas as of December 31, 2007. At December 31, 2007, our estimated net proved reserves in East Texas were 202.5 Bcfe, with net production of approximately 32.7 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 40 acres per well, with some areas down spaced to as little as 20 acres per well. Recently, operators have begun drilling horizontal wells and we are monitoring their success. We drilled 48 wells (42.0 net wells) in the Cotton Valley Trend in 2007. We currently have 6 rigs running in this region and expect to drill an additional 71 wells during 2008.

Gulf Coast

We own natural gas and oil interests in 50,768 gross (33,317 net) acres in the Gulf Coast area as of December 31, 2007, which encompasses the large coastal plain from the southernmost tip of Texas through the southern portion of Louisiana. As of December 31, 2007, our estimated net proved reserves in the Gulf Coast area were 97.8 Bcfe, with net production of approximately 42.5 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. We drilled three wells in the Gulf Coast in 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 December 31, 2007, our estimated net proved reserves were 60.1 Bcfe, with net production of approximately 18.3 Mmcfe per day for the month of December 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 this area we generally own non-operating interests in blocks operated by 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.

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 December 31, 2007, we own 31,847 gross (22,941 net) acres in these prospects. As of December 31, 2007, our estimated net proved reserves were 38.0 Bcfe. We have identified 77 potential drilling locations in these fields, including 63 proved undeveloped locations, and intend to drill approximately 21 development wells in 2008.

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 December 31, 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 2008 and intend to manage our investment in this area to maximize returns without significantly increasing future capital expenditures.

Other. We own interests in properties in the Arkoma and Anadarko Basins and other areas. As of December 31, 2007, we held interests in 443,546 gross (163,894 net) leasehold and option acres in these areas. During 2007, our acreage in Oklahoma grew to 371,006 gross (121,387 net) acres. As we continue to drill and expand our acreage positions, our Oklahoma prospects may become increasingly important to our Company.

Tertiary Oil Recovery

Wellman Unit. The Wellman Unit is part of our tertiary oil recovery operations. The Wellman Field, located in Terry County, Texas 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 83.7 Mmboe to date. We recently re-initiated injection of CO_2, and our injection rate averaged 10.9 Mmcf per day in 2007 and we expect to reach an average 30.9 Mmcf per day over the next 10 years. As of December 31, 2007, net proved reserves attributable to the Wellman Unit were 9.3 Mmboe. We also own a CO_2 recycling plant at this unit with a capacity of 28 Mmcf per day. The plant includes 6,000 horsepower of CO_2 compression and 4,850 horsepower of processing compression, which is sufficient to handle the recycling of the CO_2 that will be produced in association with the production of these reserves.

George Allen Unit. The George Allen Unit, located in Gaines County, Texas covers 800 gross acres in the George Allen Field and produces from the San Andres formation from an average depth of 4,950 feet. We have also leased an additional 320 acres adjacent to the unit to the south. 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 1.6 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 implementing a nine pattern pilot program. CO_2 injection began in December 2007 at 2.0 Mmcf per day. Injection is expected to increase to 15 Mmcf per day by mid-year 2008. As of December 31, 2007, net proved reserves attributable to the George Allen Field were 8.0 Mmboe. As of December 31, 2007, the CO_2 injection rate was 2.0 Mmcf per day.

South Mallet Unit. The South Mallet Unit, located in Hockley County, Texas covers 3,540 gross acres in the Slaughter/Levelland Field complex and produces from the San Andres formation from an average depth of 5,000 feet. These fields are some of the largest in West Texas and currently have ten active CO_2 floods and four more at various stages of readiness. The South Mallet Unit has produced 27.8 Mmboe to date. We are currently evaluating the project for CO_2 development with plans to begin injection of CO_2 in 2009. We expect to reach an injection rate of approximately 18 Mmcf per day by the beginning of 2010. As of December 31, 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, 2007, 2006 and 2005. The PV-10 and Standardized Measure shown in the table are not intended to represent the current market value of our estimated natural gas and oil reserves. At December 31, 2007, approximately 56% of our proved reserves were proved undeveloped reserves. Based on our current drilling schedule, we estimate that 88% 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 89% of our total proved reserves as of December 31, 2007, approximately 92% of our total proved reserves as of

December 31, 2006 and 1.5% of our total proved reserves as of December 31, 2005. DeGolyer and MacNaughton prepared the reports of proved reserves for PetroSource (our tertiary oil reserves located in West Texas), which constitute approximately 8% of our total proved reserves as of December 31, 2007, approximately 7% of our total proved reserves as of December 31, 2006 and approximately 98% of our total proved reserves as of December 31, 2005. The remaining 3%, 1% and 0.5% of our proved reserves as of December 31, 2007, 2006 and 2005 were based on internally prepared estimates.

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	December 31,		
	2007	2006	2005
Estimated Proved Reserves(1)			
Natural gas (Bcf)(2)	1,297.0	850.7	237.4
Oil (MmBbls)	36.5	25.2	10.4
Total (Bcfe)	1,516.2	1001.8	300.0
PV-10 (in millions)(3)	$ 3,550.5	$ 1,734.3	$ 733.3
Standardized Measure of Discounted Net Cash Flows (in millions)(4)	$ 2,718.5	$ 1,440.2	$ 499.2

(1) Our estimated proved reserves and the future net revenues, PV-10, and Standardized Measure of Discounted Net Cash Flows were determined using year end prices for natural gas and oil as of December 31, 2007, 2006 and 2005. The calculated weighted average prices were $6.46 per Mcf of natural gas and $87.47 per barrel of oil at December 31, 2007, $5.32 per Mcf of natural gas and $54.62 per barrel of oil at December 31, 2006 and $8.40 per Mcf of natural gas and $54.02 per barrel of oil at December 31, 2005.

(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 on future net revenues. Neither PV-10 nor Standardized Measure represents 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,		
	2007	2006 (In millions)	2005
Standardized Measure of Discounted Net Cash Flows	$ 2,718.5	$ 1440.2	$ 499.2
Present value of future income tax discounted at 10%	832.0	294.1	234.1
PV-10	$ 3,550.5	$ 1,734.3	$ 733.3

(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 are used to calculate PV-10. Standardized Measure differs from PV-10 because Standardized Measure includes the effect of future income taxes.

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.

Production and Price History

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

	Year Ended December 31,		
	2007	**2006**	**2005**
Production Data:			
Natural gas (Mmcf)	51,958	13,410	6,873
Oil (MBbls)	2,042	322	72
Combined equivalent volumes (Mmcfe)	64,211	15,342	7,305
Average daily combined equivalent volumes (Mmcfe/d)	175.9	42.0	20.0

	Year Ended December 31,		
	2007	**2006**	**2005**
Average Prices(1):			
Natural gas (per Mcf)	$ 6.51	$ 6.19	$ 6.54
Oil (per Bbl)	$ 68.12	$ 56.61	$ 48.19
Combined equivalent (per Mcfe)	$ 7.45	$ 6.60	$ 6.63

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

	Year Ended December 31,		
	2007	**2006**	**2005**
Expenses per Mcfe:			
Lease operating expenses:			
Transportation	$ 0.12	$ 0.22	$ 0.16
Processing and gathering(1)	0.28	0.37	0.42
Other lease operating expenses	1.25	1.70	1.64
Total lease operating expenses	$ 1.65	$ 2.29	$ 2.22

Production taxes	$ 0.30	$ 0.30	$ 0.43

(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 the number of productive wells in which we owned a working interest at December 31, 2007. Productive wells consist of producing wells and wells capable of producing, including natural gas wells awaiting pipeline connections

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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	471	435
East Texas	177	163
Gulf Coast	214	133
Other:		
Gulf of Mexico	67	43
Other West Texas	264	251
Tertiary recovery West Texas (PetroSource)	46	43
Piceance Basin	52	20
Other, including Oklahoma	363	146
Total	1,654	1,234

Developed and Undeveloped Acreage

The following table sets forth information at December 31, 2007:

	Developed Acreage(1)		Undeveloped Acreage(2)	
Area	Gross(3)	Net(4)	Gross(3)	Net(4)
WTO	13,157	10,824	587,389	497,921
East Texas	28,084	25,891	25,304	6,848
Gulf Coast	39,438	24,678	11,330	8,639
Other:				
Gulf of Mexico	73,614	36,770		
Other West Texas	24,272	16,030	7,575	6,911
Tertiary recovery West Texas (PetroSource)	9,064	8,195		
Piceance Basin	1,800	451	38,534	15,235
Other, including Oklahoma	86,498	43,255	357,048	120,639
Total	275,927	166,094	1,027,180	656,193

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

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

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

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

Many of the leases comprising the acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production. We generally have been able to obtain extensions of the primary terms of our federal leases when we have been unable to obtain drilling permits due to a pending Environmental Assessment, Environmental Impact Statement or related

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legal challenge. The following table sets forth as of December 31, 2007 the expiration periods of the gross and net acres that are subject to leases in the acreage summarized in the above table.

Twelve Months Ending	Acres Expiring Gross	Acres Expiring Net
December 31, 2008	46,635	36,198
December 31, 2009	135,669	121,134
December 31, 2010	356,993	162,761
December 31, 2011 and later	390,181	279,038
Other(1)	373,629	223,156
Total	1,303,107	822,287

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

Drilling Activity

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. Gross refers to the total wells in which we had a working interest and net refers to gross wells multiplied by our working interest.

	2007				2006				2005			
	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent
Development:												
Productive	281	99.3%	244.4	99.5%	82	94%	50.8	95%	31	100%	13.0	100%
Dry	2	0.7%	1.3	0.5%	5	6%	2.5	5%				
Total	283	100%	245.7	100%	87	100%	53.3	100%	31	100%	13.0	100%
Exploratory:												
Productive	27	82%	24.3	84%	19	76%	13.0	72%	2	22%	0.8	22%
Dry	6	18%	4.7	16%	6	24%	5.0	28%	7	78%	2.9	78%
Total	33	100%	29.0	100%	25	100%	18.0	100%	9	100%	3.7	100%
Total:												
Productive	308	98%	268.7	98%	101	90%	63.8	89%	33	83%	13.8	83%
Dry	8	2%	6.0	2%	11	10%	7.5	11%	7	17%	2.9	17%

316	100%	274.7	100%	112	100%	71.3	100%	40	100%	16.7	100%

At December 31, 2007, we had 40 wells in process.

Drilling Rigs

The following table sets forth information with respect to the drilling on our acreage as of December 31, 2007.

Area	**Owned(1)**	**Third-Party**
WTO	28	2
East Texas		6
Gulf Coast		1
Other, including Oklahoma	1	2
Total	29	11

(1) Includes rigs owned by Lariat, our wholly owned subsidiary, and by Larclay, a limited partnership in which we have a 50% interest.

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, 2007, we sold natural gas to 24 different purchasers.

The top five natural gas purchasers of our WTO production for the year ended December 31, 2007 and each company s approximate percentage of total sales during that period are listed below:

Gas Purchasers	**%**
Magnus Energy Marketing, Ltd.	25.0%
ANP Funding I, LLC	21.4%
Atmos Energy Corporation	12.9%
City of Austin, Texas	10.9%
El Paso Industrial Energy, LP	10.5%

In light of access to numerous other purchasers through existing pipeline interconnections, we do not believe the loss of any of our major gas purchasers would have a material effect on our business.

See Note 21 in the consolidated financial statements included in this report regarding major customers.

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. Our natural gas and oil properties are subject to customary royalty and other interests, liens for current taxes and other burdens which we believe do not materially interfere with the use of or affect our carrying value of the properties.

Drilling and Oil Field Services

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 have a 50% interest in a limited partnership, Larclay, that owns and operates drilling rigs. We believe that our ownership of drilling rigs and our related oil field services will continue to be a catalyst of our growth. As of December 31, 2007, 22 of our rigs and seven Larclay rigs were working on properties operated by us, and we operated 43 rigs, including eleven of the twelve rigs owned by Larclay. Our rig fleet is designed to drill in our specific areas of operation and have an average horsepower of over 800 and an average depth capacity of greater than 10,500 feet.

In 2005, we ordered 22 rigs from Chinese manufacturers for an aggregate purchase price of $126.4 million, which included 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. We anticipate the retrofit will be completed in the second quarter of 2008.

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

	Year Ended December 31, 2007	2006	2005
Number of operational rigs owned at end of period	25	25	19
Average number of operational rigs owned during the period	26.0	21.9	14.3
Average number of rigs utilized	23.8	21.9	14.3
Average drilling revenue per rig per day(1)(2)	$ 17,177	$ 17,034	$ 11,503

(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.

The table below identifies certain information concerning our drilling rigs as of December 31, 2007:

	Owned	Operational	Idle	Operating for SandRidge	Operating for Third Parties
Lariat	32(1)	25	0	22	3
Larclay	12(2)	11	1	7	3
Total	44	36	1	29	6

(1) Includes three rigs that were being retrofitted and four rigs that are non-operational.

(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 exploration and production operation. These services include providing pulling units, coiled-tubing units, trucking, location and road construction roustabout services and rental tools to ourselves and to third parties. Less than 28% of our oil field services in 2007 were performed for third parties. We also provide underbalanced drilling systems for our own wells. Our capital expenditures for 2007 related to our oil field services were $123.2 million and we have budgeted approximately $50 million in capital expenditures in 2008 for oil field services.

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 and approximately one-third with the other operators in West Texas. For the year ended December 31, 2007, we generated revenues of $38.1 million for drilling services performed for third parties, with Mariner Energy, Inc. accounting for $19.0 million of those revenues.

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Midstream Gas Services

We provide gathering, compression, processing and treating services of natural gas in the TransPecos region of West Texas and the Piceance Basin in Colorado. 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 December 31, 2007:

Gas Plants		Plant Capacity (Mmcf/d)	Average Utilization(1)	Third-Party Usage
Pike s Peak(2)	West Texas	70	90%	1%
Grey Ranch(3)	West Texas	92	89%	31%
Sagebrush(4)	Piceance Basin	50	24%	21%

(1) Average utilization for the year ended December 31, 2007.

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

(3) A project to expand the plant to 92 Mmcf/per day was completed during the fourth quarter of 2007. The plant capacity is expected to be further increased to 170 Mmcf/per day by the third quarter of 2008.

(4) Sagebrush commenced processing operations on May 1, 2007. Current throughput is 22 Mmcf per day, increasing utilization to 44%.

PetroSource Facilities (West Texas)	CO_2 Compression Capacity (Mmcf/d)	Average Utilization(1)
Pike s Peak	38	63%
Mitchell	26	41%
Grey Ranch	40	59%
Terrell	38	66%

(1) Average utilization for year ended December 31, 2007.

West Texas

In Pecos County, we operate and own the Pike s Peak gas treating plant, which has the capacity to treat 70 Mmcf per day of gas for the removal of CO_2 from natural gas produced in the Piñon Field and nearby areas. We also own the Grey Ranch CO_2 treatment plant located in Pecos County and have a 50% interest in the partnership that leases the plant from us under a lease expiring in 2010. Our 50% partner, Southern Union, operates the plant. 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 averages 65%

CO_2.

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 access for up to 60 Mmcf per day of treating capacity at Anadarko Petroleum Corporation s Mitchell Plant under a long term fixed fee arrangement.

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

The majority of the produced natural gas gathered by our midstream assets in West Texas requires compression from the wellhead to the final sales meter. As of December 31, 2007, we currently own and operate approximately 45,000 horsepower of gas compression and anticipate installing an additional 40,000 horsepower in 2008.

Other Areas

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

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

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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. During 2007, we spent approximately $73.8 million in capital expenditures to install pipeline and compression infrastructure to accommodate our growth in production and for increased treating capacity for high CO_2 gas, adding approximately 75 Mmcf per day in additional treating capacity. We anticipate adding approximately 80 Mmcf per day in additional treating capacity in 2008. We have budgeted approximately $107 million in 2008 capital expenditures for our midstream and other segments.

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 purchase and sell residue gas from the Sagebrush plant into Questar Corporation 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 FERC* 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. We currently have 75,000 MmBtu per day of firm transportation service subscribed on the Oasis Pipeline for a portion of our Piñon Field production for 2008.

Other Operations

Our CO_2 gathering, merchant sales and tertiary oil recovery operations are conducted through PetroSource. PetroSource owns 231 miles of CO_2 pipelines in West Texas with approximately 88,000 horsepower of owned and leased CO_2 compression available with approximately 54,000 horsepower currently operational. In addition, PetroSource has exclusive long-term supply contracts to gather CO_2 from natural gas treatment plants in West Texas and is the sole gatherer of CO_2 from the four natural gas treatment plants located in the Delaware and Val Verde Basins of West Texas. Our CO_2 supply is primarily used in our and third parties tertiary oil recovery operations. We have assembled an experienced CO_2 management team, including engineers and geologists with extensive experience in CO_2 flooding with industry leaders.

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

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

PetroSource currently has approximately 95 Mmcf per day of CO_2 in available supply. We currently deliver the majority of this supply to Occidental Permian Ltd. and Pure Resources L.P. In December 2007, we captured and sold 92 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 an average of 65 to 75 Mmcf of CO_2 per day over the next five years. We intend to increase our supply

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of CO_2 in order to provide sufficient capacity for our tertiary oil recovery operations. 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 CO_2 needs, as well as the expansion of our merchant sales business. Currently, two additional compressors are being refurbished at the Grey Ranch and Mitchell Plant. These units will add over 11,000 horsepower and over 30 Mmcf per day of capacity.

Future regulation of greenhouse gas emissions may provide the Company an opportunity to create economic benefits in the form of Emissions Reduction Credits (ERCs), but such regulation may also impose burdens on the conduct and cost of our operations. Recently, a number of states and regions 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. These legislative and regulatory efforts may result in legal requirements that create a more active and more valuable market in which to trade ERCs, although the timing and scope of future legal requirements governing greenhouse gases remain uncertain. We currently capture approximately 1.5 million metric tons of CO_2 per year. We may benefit from such capture to the extent it results in ERCs that can be traded or can be used by us to meet future compliance obligations that may otherwise be costly to satisfy. ERCs of just over 170,000 tonnes were sold on the voluntary market during 2007.

Competition

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

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

We believe the type, age and condition of our drilling rigs, the quality of our crew and the responsiveness of our management generally enable us to compete effectively. However, to the extent we drill for third parties, we encounter substantial competition from other drilling contractors. Our primary market area is highly competitive. The drilling contracts we compete for are sometimes awarded on the basis of competitive bids.

We believe pricing and rig availability are the primary factors our potential customers consider in determining which drilling contractor to select. While we must be competitive in our pricing, our competitive strategy generally emphasizes the quality of our equipment, the experience of our rig crews and our willingness to drill on a turnkey basis, to differentiate us from our competitors. This strategy is less effective when demand for drilling services is weak or there is an oversupply of rigs, as these conditions usually result in increased price competition, which makes it more difficult for us to compete on the basis of factors other than price. Many of our competitors have greater financial, technical and other resources than we do. Their greater capabilities in these areas may enable them to better withstand industry downturns and better retain skilled rig personnel.

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

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

Environmental Matters and Regulation

General

We are subject to extensive and complex federal, state and local laws and regulations governing the protection of the environment and of the health and safety of our employees. 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;
- require safety-related procedures and personal protective equipment to be used during operations;
- restrict the types, quantities and concentrations 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; 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 potentially criminal penalties. The effects of these laws and regulations, as well as other laws or regulations that may be adopted in the future, could have a material adverse impact on our business, financial condition and results of operations. Below is a discussion of the environmental laws and regulations that could have a material impact on the oil and gas industry.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, also known as the Superfund law, and analogous state laws impose joint and several liability, without regard to fault or legality of conduct, on specific classes of persons for the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to strict joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of related environmental and 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 at and could migrate from some of our properties and may warrant or require investigation or remediation or other response action. 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 or to which hazardous substances may have been released or deposited.

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Waste Handling

The Resource Conservation and Recovery Act, or RCRA, and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the U.S. Environmental Protection Agency, or EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of crude oil or natural gas are currently excluded from regulation as RCRA hazardous wastes but instead are regulated under RCRA s non-hazardous waste provisions. However, it is possible that certain natural gas and oil exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change would likely increase our operating expenses, which could have a material adverse effect on our business, financial condition or results of operations as well as on the industry in general.

Air Emissions

The Federal Clean Air Act and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. These regulatory programs may require us to obtain permits before commencing construction on a new source of air emissions, and they may require us to reduce emissions or to install expensive emission control technologies at existing facilities and new facilities. As a result, we may be required to incur increased capital and operating costs at existing and new facilities. For instance, the Grey Ranch natural gas treatment plant operates under a permit granted by the Texas Commission on Environmental Quality, or TCEQ that currently allows us to vent CO_2 emissions. Effective March 2009, we will be required to install control devices that limit the quantity of organic compounds vented by the plant. We are in the process of refurbishing existing compressors at an estimated cost of $4.0 million, which will enable us to capture the CO_2 for ultimate delivery to the marketplace. Additional expenses and capital costs may be required for us to maintain or achieve compliance with current and future laws governing air emissions.

We are subject to air quality compliance reviews by federal and state agencies, and the failure to meet applicable requirements may result in enforcement action, including fines and penalties. In February 2008, we received a notice of alleged violations from TCEQ for certain monitoring and recordkeeping deficiencies and emissions in excess of allowable limits at our Pike s Peak processing plant in 2007. We are preparing a response regarding corrective action taken with regard to the alleged violations.

Water Discharges

The Federal Water Pollution Control Act, or the Clean Water Act, and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances into waters of the United States, including wetlands, as well as state waters. These laws prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and other substances related to the oil and natural gas industry into onshore, coastal and offshore waters without appropriate permits. Some of the pollutant limitations have become more restrictive over the years, and additional restrictions and limitations including technology requirements and receiving water limits, 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 potentially 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 that implement OPA impose a variety of regulations on responsible parties related to the prevention of oil spills and liability for clean up and natural resource damages resulting from such spills. For example, some of our facilities in the Gulf Coast region 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 or otherwise requiring federal approval 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 may

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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 is 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. The NEPA process has the potential to delay or even prohibit our development of natural gas and oil projects in covered areas.

Future 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 restrict or regulate emissions of greenhouse gases. At least 17 states, as well as other regions, have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emissions inventories and regional greenhouse gas cap-and-trade programs. Also, as a result of the U.S. Supreme Court s decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA may be required to regulate greenhouse gas emissions from mobile sources, *e.g.*, cars and trucks, even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The court s holding in *Massachusetts, et al. v. EPA,* that greenhouse gases fall under the federal Clean Air Act s definition of air pollutant , may lead to future regulation of greenhouse gas emissions from stationary sources under certain Clean Air Act programs. 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-related 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, may have an adverse effect on demand for our services or products and may result in compliance obligations with respect to the release, capture and use of carbon dioxide that could have an adverse effect on our operations.

Anti-Terrorism Measures

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

Other Regulation of the Natural Gas and Oil Industry

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

Drilling and Production

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

- the location of wells;
- the method of drilling and casing wells;
- the rates of production or allowables ;
- the surface use and restoration of properties upon which wells are drilled;

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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. Minerals Management Service of the U.S. Department of the Interior, or 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 currently pursued by FERC and Congress will continue indefinitely into the future nor can we determine what effect, 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, nondiscriminatory 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 in state 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 December 31, 2007, we had 2,219 full-time employees and 8 part-time employees, including more than 150 geologists, geophysicists, petroleum engineers, technicians, land and regulatory professionals. Of our 2,227 employees, 335 are located at our headquarters in Oklahoma City, Oklahoma, eight in Amarillo, Texas and the remaining 1,884 employees are working in our various field offices and at our drilling sites.

Offices

As of December 31, 2007 we lease 80,861 square feet of office space in Oklahoma City, Oklahoma at 1601 N.W. Expressway, where our principal offices are located. The term of the lease expires on August 31, 2009. In July 2007, we purchased property to serve as our future corporate headquarters. The 3.51-acre site contains four buildings and is located in downtown Oklahoma City, Oklahoma.

We also lease or sublease 28,887 square feet of office space in Amarillo, Texas at 701 S. Taylor Street, where our principal offices were previously located. The leases expire in April 2009. We lease 6,725 square feet of office space at 16801 Greenspoint Park Drive in Houston, Texas under a lease expiring in January 2014. PetroSource currently leases approximately 7,848 square feet in Midland, Texas under a lease expiring in December 2008. We own two buildings in Fort Stockton, Texas that combined total 9,292 square feet. Adjacent to these buildings, we own approximately 31,620 square feet of office and shop space. We also own an approximate 10,000 square foot office building in Midland, Texas and own 4,358 square feet of office space and 6,240 square feet of shop space in Odessa, Texas. In addition, we lease a field office located in Longview and Odessa, Texas, Yukon, Oklahoma, Shreveport, Louisiana and Rifle, Colorado.

Glossary of Natural Gas and Oil Terms

The following is a description of the meanings of some of the natural gas and oil industry terms used in this Annual Report on Form 10-K.

2-D seismic or 3-D seismic. Geophysical data that depict the subsurface strata in two dimensions or three dimensions, respectively. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D seismic.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to crude oil or other liquid hydrocarbons.

Bcf. Billion cubic feet of natural gas.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

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

Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

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

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

CO_2. Carbon Dioxide.

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

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

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

Environmental Assessment (EA). A study to determine whether a federal action significantly affects the environment, which federal agencies may be required by the National Environmental Policy Act or similar state statutes to undertake prior to the commencement of activities that would constitute federal actions, such as natural gas and oil exploration and production activities on federal lands.

Environmental Impact Statement. A more detailed study of the environmental effects of a federal undertaking and its alternatives than an EA, which may be required by the National Environmental Policy Act or similar state statutes, either after the EA has been prepared and determined that the environmental consequences of a proposed federal undertaking, such as natural gas and oil exploration and production activities on federal lands, may be significant, or without the initial preparation of an EA if a federal agency anticipates that a proposed federal undertaking may significantly impact the environment.

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

Field. An area consisting of either a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

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Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

High CO_2 gas. Natural gas that contains more than 10% CO_2 by volume.

Imbricate stacking. A geological formation characterized by multiple layers lying lapped over each other.

MBbls. Thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. Thousand cubic feet of natural gas.

Mcf/d. Mcf per day.

Mcfe. Thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MmBbls. Million barrels of crude oil or other liquid hydrocarbons.

Mmboe. Million barrels of oil equivalent.

MBtu. Thousand British Thermal Units.

MmBtu. Million British Thermal Units.

Mmcf. Million cubic feet of natural gas.

Mmcf/d. Mmcf per day.

Mmcfe. Million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Mmcfe/d. Mmcfe per day.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells, as the case may be.

Plugging and abandonment. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.

Present value of future net revenues (PV-10). The present value of estimated future revenues to be generated from the production of proved reserves, before income taxes, calculated in accordance with SEC guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation and without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization. PV-10 is calculated using an annual discount rate of 10%.

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

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed reserves. Has the meaning given to such term in Rule 4-10(a)(3) of Regulation S-X, which defines proved developed reserves as:

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved reserves. Has the meaning given to such term in Rule 4-10(a)(2) of Regulation S-X, which defines proved reserves as:

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

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

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

(iii) Estimates of proved reserves do not include the following: (A) Oil that may become available from known reservoirs but is classified separately as indicated additional reserves; (B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved undeveloped reserves. Has the meaning given to such term in Rule 4-10(a)(4) of Regulation S-X, which defines proved undeveloped reserves as:

Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Pulling Units. Pulling units are used in connection with completions and workover operations.

PV-10. See Present value of future net revenues.

Rental Tools. A variety of rental tools and equipment, ranging from trash trailers to blow out preventors to sand separators, for use in the oil field.

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

Roustabout Services. The provision of manpower to assist in conducting oil field operations.

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

Stratigraphic play. An oil or natural gas formation contained within an area created by permeability and porosity changes characteristic of the alternating rock layer that result from the sedimentation process.

Trucking. The provision of trucks to move our drilling rigs from one well location to another and to deliver water and equipment to the field.

Underbalanced drilling. The procedure used to drill oil and gas wells where the pressure in the wellbore is kept lower than the fluid pressure in the formation being drilled.

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

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.

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Item 1A. *Risk Factors*

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 report. See Business and Properties 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 report. 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 December 31, 2007, only 771 of our 4,594 identified potential future well locations were attributed 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 Form 10-K. A prospect is a property on which we have identified what our geoscientists believe, based on available seismic and geological information, to be indications of natural gas or oil. Our prospects and drilling locations are in various stages of evaluation, ranging from a prospect that is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation.

The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. Even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from the well or abandonment of the well. During 2007, we participated in drilling a total of 316 gross wells, of which eight have been identified as dry holes. 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 55.3% of the estimated proved reserves that we own or have under lease in the WTO as of December 31, 2007 are proved undeveloped reserves and 56.1% 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 December 31, 2007, approximately 60.8% of our proved reserves and approximately 42.1% 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 CO2 content, which can negatively affect our economics.

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

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

Since the treatment expenses are incurred on an Mcf basis, we will incur a higher effective treating cost per MmBtu of natural gas sold for natural gas with a higher CO_2 content. As a result, high CO_2 gas wells must produce at much higher rates than low CO_2 gas wells to be economic, especially in a low natural gas price environment.

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. We have no control over many 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 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. The effect of any material decrease in the volume of natural gas handled by our midstream assets would be to reduce our revenues, operating income and cash flows.

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

A significant aspect of our exploration and development plan involves seismic data. Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are present in those structures. Other geologists and petroleum professionals, when studying the same seismic data, may have significantly different interpretations than our professionals.

In addition, the use of 2-D and 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses due to such expenditures. As a result, our drilling activities may not be geologically successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area may not improve.

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

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

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

- unusual or unexpected geological formations and miscalculations;
- pressures;
- fires;
- blowouts;
- loss of drilling fluid circulation;
- title problems;
- facility or equipment malfunctions;
- unexpected operational events;
- shortages of skilled personnel;
- shortages or delivery delays of equipment and services;

compliance with environmental and other regulatory requirements; and

adverse weather conditions.

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

Insurance against all operational risks is not available to us. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. We do not carry environmental insurance, for example. We could incur losses 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.

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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 on sour gas treating 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, debt 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 December 31, 2007, our total indebtedness was $1.1 billion, which represented approximately 38% 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 us. For example, it could:

- make us more vulnerable to adverse changes in general economic, industry and competitive conditions and adverse changes in government regulation;
- require us to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness, thereby reducing the availability of our cash flows to fund working capital, capital expenditures, acquisitions and other general corporate purposes;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- place us at a competitive disadvantage compared to our competitors that are less leveraged and, therefore, may be able to take advantage of opportunities that our leverage prevents us from pursuing; and
- limit our ability to borrow additional amounts for working capital, capital expenditures, acquisitions, debt service requirements, execution of our business strategy or other purposes.

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

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

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

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

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

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

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

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

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

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

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

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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 and Properties 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 and regions 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.

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. Management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with generally accepted accounting principles. A material weakness is a deficiency, or a combination of deficiencies, in our internal control over financial reporting that results in a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis. Effective internal controls are necessary for us to provide reliable financial reports and effectively prevent fraud. If we cannot provide reliable financial reports or prevent fraud,

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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.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

Information regarding our properties is included in Item 1 and in Note 6 of the notes to our consolidated financial statements included in Item 8 of this report.

Item 3. ***Legal Proceedings***

The Company is a defendant in lawsuits from time to time in the normal course of business. In management s opinion, the Company is not currently involved in any legal proceedings which, individually or in the aggregate, could have a material effect on the financial condition, operations and/or cash flows of the Company.

Item 4. ***Submission of Matters to a Vote of Security Holders***

Not applicable.

PART II

Item 5. ***Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

Price Range of Common Stock

Following our initial public offering, our common stock commenced trading on the New York Stock Exchange under the symbol SD on November 6, 2007. Prior to November 6, 2007, there was no active market for our common stock. For the period November 6, 2007 to December 31, 2007, the high and low sales prices per share of our common stock as reported by the New York Stock Exchange were $36.11 per share and $29.53 per share, respectively.

At February 29, 2007, there were 503 holders of record of our common stock and approximately 10,532 beneficial owners.

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. The terms of our revolving credit facility and senior term loans restrict our ability to pay dividends to holders of common stock. The certificate of designation for our convertible preferred stock also 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. This transaction did not involve any underwriter or a public offering, and we believe this transaction was exempt from registration requirements pursuant to Section 4(2) of the Securities Act and Regulation D promulgated thereunder.

Recent Sales of Unregistered Securities

On March 20, 2007, we sold approximately 17.8 million shares of our common stock for net proceeds of $318.7 million, after deducting offering expenses of approximately $1.4 million. The stock was sold in private sales as follows: 11.1 million shares to affiliates of Ares Management LLC (Ares), a private institutional investment firm, for $200 million, and 2.8 million shares to an affiliate of Tom L. Ward, the Company s Chairman, Chief Executive Officer and largest stockholder for $50 million. In addition to the 13.9 million shares sold to Ares and the affiliate of Mr. Ward, holders of the Company s outstanding Series A Convertible Preferred Shares and Common Units exercised preemptive rights resulting in the sale of an additional 3.9 million shares for $70 million. An affiliate of Mr. Ward exercised the right to acquire 0.6 million of the preemptive shares for $11.4 million, bringing the total shares purchased by Mr. Ward s affiliates to 3.4 million shares at a purchase price of $61.4 million. All shares were sold at $18 per share.

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Use of Proceeds from Sales of Registered Securities

On November 9, 2007, we completed the initial public offering of our common stock. We sold 32,379,500 shares at a price of $26 per share. We received net proceeds of approximately $794.7 million after deducting underwriting discounts and offering expenses of approximately $47.1 million. We used the net proceeds to repay the outstanding indebtedness under our senior credit facility ($515.9 million), to repay a note related to a recent acquisition ($49.1 million), and to fund the remainder of our 2007 capital expenditure program and a portion of our 2008 capital expenditure program ($229.7 million).

Issuer Purchases of Equity Securities

As part of our restricted stock plan, we make required tax payments on behalf of employees as their stock awards vest and then withhold a number of vested shares having a value on the date of vesting equal to the tax obligation. The shares withheld were recorded as treasury shares. During the period November 5, 2007 to December 31, 2007, we purchased the following shares:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
November 5-30	1,098	$ 31.88	N/A	N/A
December 1-31			N/A	N/A

Item 6. *Selected Financial Data*

The following table sets forth, as of the dates and for the periods indicated, our selected financial information. Our financial information is derived from our audited consolidated financial statements for such periods. The financial data includes the results of the acquisition of NEG effective November 21, 2006. The information should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and our consolidated financial statements and notes thereto contained in this document. The following information is not necessarily indicative of our future results.

	Years Ended December 31,				
	2007	2006	2005	2004	2003
	(In thousands, except per share data)				
Statement of Operations Data:					
Revenues	$ 677,452	$ 388,242	$ 287,693	$ 175,995	$ 155,337
Expenses:					
Production	106,192	35,149	16,195	10,230	7,980

Production taxes	19,557	4,654	3,158	2,497	2,099
Drilling and services	44,211	98,436	52,122	26,442	13,847
Midstream marketing	94,253	115,076	141,372	96,180	94,620
Depreciation, depletion and amortization natural gas and crude oil	173,568	26,321	9,313	4,909	3,298
Depreciation, depletion and amortization other	53,541	29,305	14,893	7,765	5,284
General and administrative	61,780	55,634	11,908	6,554	3,705
Loss (gain) on derivative contracts	(60,732)	(12,291)	4,132	878	3,450
Loss (gain) on sale of assets	(1,777)	(1,023)	547	(210)	(1,284)
Total operating expenses	490,593	351,261	253,640	155,245	132,999
Income from operations	186,859	36,981	34,053	20,750	22,338

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	Years Ended December 31,				
	2007	2006	2005	2004	2003
	(In thousands, except per share data)				
Other income (expense):					
Interest income	5,423	1,109	206	56	103
Interest expense	(117,185)	(16,904)	(5,277)	(1,678)	(1,208)
Minority interest	276	(296)	(737)	(262)	(96)
Income (loss) from equity investments	4,372	967	(384)	(36)	1,056
Total other income (expense)	(107,114)	(15,124)	(6,192)	(1,920)	(145)
Income before income taxes	79,745	21,857	27,861	18,830	22,193
Income tax expense	29,524	6,236	9,968	6,433	7,585
Income from continuing operations	50,221	15,621	17,893	12,397	14,608
Income (loss) from discontinued operations, net of tax			229	451	(85)
Cumulative effect of accounting change					(1,636)
Extraordinary gain				12,544	
Net income	50,221	15,621	18,122	25,392	12,887
Preferred stock dividends and accretion	39,888	3,967			
Income (loss) available (applicable) to common stockholders	$ 10,333	$ 11,654	$ 18,122	$ 25,392	$ 12,887

	Historical				
	Years Ended December 31,				
	2007	2006	2005	2004(2)	2003(1)
	(In thousands, except per share data)				
Earnings Per Share Information:					
Basic and Diluted					
Income from continuing operations	$ 0.46	$ 0.21	$ 0.31	$ 0.22	$ 0.26
Income (loss) from discontinued operations, net of income tax			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	(0.37)	(0.05)			
Income per share available to common stockholders	$ 0.09	$ 0.16	$ 0.32	$ 0.45	$ 0.23

Weighted average number of common shares outstanding(3):					
Basic	108,828	73,727	56,559	56,312	56,312
Diluted	110,041	74,664	56,737	56,312	56,312

(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.

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	As of December 31,				
	2007	2006	2005	2004	2003
			(In thousands)		
Balance Sheet Data:					
Cash and cash equivalents	$ 63,135	$ 38,948	$ 45,731	$ 12,973	$ 176
Property, plant and equipment, net	$ 3,337,410	$ 2,134,718	$ 337,881	$ 114,818	$ 70,289
Total assets	$ 3,630,566	$ 2,388,384	$ 458,683	$ 197,017	$ 127,744
Long-term debt	$ 1,067,649	$ 1,066,831	$ 43,133	$ 59,340	$ 24,740
Redeemable convertible preferred stock	$ 450,715	$ 439,643	$	$	$
Total stockholders equity	$ 1,766,891	$ 649,818	$ 289,002	$ 59,330	$ 33,940
Total liabilities and stockholders equity	$ 3,630,566	$ 2,388,384	$ 458,683	$ 197,017	$ 127,744

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

Introduction

The following discussion and analysis is intended to help the reader understand our business, financial condition, results of operations, liquidity and capital resources. This discussion and analysis is provided as a supplement to, and should be read in conjunction with, the other sections of this Annual Report on Form 10-K, including: Items 1 and 2. Business and Properties, Item 6. Selected Financial Data, and Item 8. Financial Statements and Supplementary Data. 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 Annual Report on Form 10-K, particularly in Item 1A - Risk Factors and Cautionary Statement Concerning Forward-Looking Statements below, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

Overview of Our Company

We are a rapidly expanding independent natural gas and oil company concentrating on exploration, development and production activities. We are focused on continuing the exploration and exploitation of our significant holdings in the West Texas Overthrust, which we refer to as the WTO, a natural gas prone geological region where we have operated since 1986 that includes the Piñon Field the South Sabino the Big Canyon Prospect and other prospects that we are currently evaluating. 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. The NEG acquisition, coupled with numerous acquisitions of additional working interests completed during 2007, 2006 and late 2005, have significantly increased our holdings in the WTO. We also operate significant interests in the Cotton Valley Trend in East Texas, the Gulf Coast area, the Gulf of Mexico, Oklahoma and the Piceance Basin of Colorado.

During November 2007, we completed the initial public offering of our common stock. We used the proceeds from this offering to repay indebtedness outstanding under our senior credit facility as well as a note payable related to a recent acquisition, to fund the remainder of our 2007 capital expenditure program and a portion of our 2008 capital expenditure program. See further discussion of these transactions in Note 18 to the consolidated financial statements contained in this Form 10-K.

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Segment Overview

We operate in four related business segments: exploration and production, drilling and oil field services, midstream gas services and other. Management evaluates the performance of our business segments based on operating income, which 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,		
	2007	2006	2005
	(In thousands)		
Segment revenue:			
Exploration and production	$ 478,747	$ 106,413	$ 54,051
Drilling and oil field services	73,202	138,657	80,151
Midstream gas services	107,578	122,892	147,499
Other	17,925	20,280	5,992
Total revenues	677,452	388,242	287,693
Segment operating income:			
Exploration and production	198,913	17,069	14,886
Drilling and oil field services	10,473	32,946	18,295
Midstream gas services	6,783	3,528	4,096
Other	(29,310)	(16,562)	(3,224)
Total operating income	186,859	36,981	34,053
Interest income	5,423	1,109	206
Interest expense	(117,185)	(16,904)	(5,277)
Other income (expense)	4,648	671	(1,121)
Income before income taxes	$ 79,745	$ 21,857	$ 27,861
Production data:			
Natural gas (Mmcf)	51,958	13,410	6,873
Oil (MBbls)	2,042	322	72
Combined equivalent volumes (Mmcfe)	64,211	15,342	7,305
Average daily combined equivalent volumes (Mmcfe/d)	175.9	42.0	20.0
Average prices- as reported(1):			
Natural gas (per Mcf)	$ 6.51	$ 6.19	$ 6.54
Oil (per Bbl)	$ 68.12	$ 56.61	$ 48.19
Combined equivalent (per Mcfe)	$ 7.45	$ 6.60	$ 6.63
Average prices- including impact of derivative contract settlements:			
Natural gas (per Mcf)	$ 7.18	$ 7.25	$ 6.54
Oil (per Bbl)	$ 68.10	$ 56.61	$ 48.19
Combined equivalent (per Mcfe)	$ 7.98	$ 7.52	$ 6.63
Drilling and oil field services:			
Number of operational drilling rigs owned at end of period	25	25	19
Average number of operational drilling rigs owned during the period	26.0	21.9	14.3

Average drilling revenue per rig per day(2)	$ 17,177	$ 17,034	$ 11,503

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

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

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.

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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 in November 2006 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 93%, there are greater intercompany eliminations that affect the consolidated financial results of our drilling and oil field service and midstream gas services segments.

Exploration and production segment revenues increased to $478.7 million in the year ended December 31, 2007 from $106.4 million in 2006, an increase of 350%, as a result of a 320% increase in production volumes and a 13% increase in the average price we received for the natural gas and oil we produced. During 2007, we increased natural gas production by 38.5 Bcf to 52.0 Bcf and increased crude oil production by 1,720 MBbls to 2,042 MBbls. The total combined 48.9 Bcfe increase in production was due primarily to acquisitions and successful drilling in the WTO.

The average price we received for our natural gas production for the year ended December 31, 2007 increased 5%, or $0.32 per Mcf, to $6.51 per Mcf from $6.19 per Mcf in 2006. The average price received for our crude oil production increased to $68.12 from $56.61 per Bbl in 2006. Including the impact of derivative contract settlements, the effective price received for natural gas for the year ended December 31, 2007 was $7.18 per Mcf as compared to $7.25 per Mcf during the comparable period in 2006. Our oil derivative contract settlements decreased our effective price received for oil by $0.02 per Bbl to $68.10 per Bbl for the year ended December 31, 2007. Our derivative contracts had no impact on effective oil prices during the year ended December 31, 2006.

For the year ended December 31, 2007, we had $198.9 million in operating income in our exploration and production segment, compared to $17.1 million in operating income in 2006. The $372.4 million increase in exploration and production segment revenues was partially offset by a $71.0 million increase in production expenses and a $147.2 million increase in depreciation, depletion and amortization, or DD&A. 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 year ended December 31, 2007, the exploration and production segment reported a $60.7 million net gain on our derivative positions ($34.5 million realized gains and $26.2 million unrealized gains) compared to a $12.3 million net gain ($14.2 million realized gains and $1.9 million unrealized 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 of Waha Hub. Unrealized gains or losses on derivative contracts represent the change in fair value of open derivative positions during the period. The change in fair value is principally measured based on period end prices as compared to the contract price. 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. 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 an 8,037 Mmcfe, or 110% increase. Approximately 4,902 Mmcfe, or 61%, of the increase was attributable to 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 per Mcfe in 2005.

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 (including a $1.9 million unrealized loss) in 2006 as compared to a $4.1 million derivative loss (including a $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 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 the 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.

As of December 31, 2007, we had 1,516.2 Bcfe of estimated net proved reserves with a PV-10 of $3,550.5 million, while at December 31, 2006 we had 1,001.8 Bcfe of estimated net proved reserves with a PV-10 of $1,734.3 million. Our Standardized Measure of Discounted Future Net Cash Flows was $2,718.5 million at December 31, 2007 as compared to $1,440.2 million at December 31, 2006 and $499.2 million at December 31, 2005. For a discussion of PV-10 and a reconciliation to Standardized Measure of Discounted Net Cash Flows, see Items 1 and 2. Business and Properties. The increase in 2007 was primarily attributable to revisions of our previous estimates due to performance and results of our drilling activity. The increase in 2006 was primarily related to the addition of the NEG reserves which was partially offset by a decrease in the price of natural gas to $5.32 per Mcf at December 31, 2006 from $8.40 per Mcf at December 31, 2005.

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. Approximately 97% of our year-end reserve estimates are prepared 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 2007. 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, 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 and Clayton Williams Energy, Inc. (CWEI) formed a limited partnership, Larclay, which acquired twelve sets of rig components and other related equipment to assemble into completed land drilling rigs. The drilling rigs were to be used for drilling on CWEI s prospects, our prospects or 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 securing financing and the purchase of the rigs. The partnership financed 100% of the acquisition cost of the rigs utilizing a guarantee by CWEI. We operate the rigs owned by the partnership. The partnership and CWEI are responsible for all costs related to the initial construction and equipping of the drilling rigs. In the event of an operating shortfall within the partnership, we, along with CWEI are responsible to fund the shortfall through loans to the partnership. We and CWEI each have a 50% interest in Larclay. We account for Larclay 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 or turnkey contract basis. Substantially all of our drilling contract revenues are derived from daywork drilling contracts. However, we generally assess the complexity and risk of operations, the on-site drilling conditions, the type of equipment to be used, the anticipated duration of the work to be performed and the prevailing market rates in determining the contract terms we offer.

Daywork Contracts. Under a daywork drilling contract, we provide a drilling rig with required personnel to our customer who supervises the drilling of the well. We are paid based on a negotiated fixed rate per day while the rig is used. Daywork drilling contracts specify the equipment to be used, the size of the hole and the depth of the well. Under a daywork drilling contract, the customer bears a large portion of the out-of-pocket drilling costs, and we generally bear no part of the usual risks associated with drilling, such as time delays and unanticipated costs. As of December 31, 2007, 24 of our rigs were operating under daywork contracts and 22 of these were working for our account. As of December 31, 2007, the 10 operating rigs owned by Larclay were operating under daywork contracts and seven of these were working for our account. The remaining three operating Larclay rigs were working for CWEI as of December 31, 2007.

Turnkey Contracts. Under a typical turnkey contract, a customer will pay us to drill a well to a specified depth and under specified conditions for a fixed price, regardless of the time required or the problems encountered in drilling the well. We provide most of the equipment and drilling supplies required to drill the well. We subcontract for related services such as the provision of casing crews, cementing and well logging. Generally we do not receive progress payments and are paid only after the well is drilled. We routinely enter into turnkey contracts in areas where our experience and expertise permit us to drill wells more profitably than under a daywork contract. As of December 31, 2007, one of our rigs was operating under a turnkey contract.

Drilling and oil field services segment revenue decreased to $73.2 million for the year ended December 31, 2007 from $138.7 million for the year ended December 31, 2006. Operating income decreased to $10.5 million during 2007 from $32.9 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 is 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 93% in the wells we operate in the WTO, and the third-party interest has declined to less than 20%. During the year ended December 31, 2007, approximately 72% of drilling and oil field service segment revenue was generated by work performed on our own account and eliminated in consolidation as compared to approximately 34% for the comparable period in 2006. The number of drilling rigs we owned increased 19% to an average of 26 rigs during 2007 from an average of 21.9 rigs in 2006. The average daily rate we received per rig of $17,177, excluding revenues for related rental equipment and before intercompany eliminations was essentially unchanged from 2006. Our rig utilization rate was 90%, representing 1,095 stacked rig days in 2007. The decline in operating income was principally attributable to the increase in the number and working interest ownership in wells drilled for our own account.

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

We believe our ownership of drilling rigs and related oil field services will continue to be a major catalyst of our growth. As of December 31, 2007, our drilling fleet consisted of 44 rigs, including the twelve rigs owned by Larclay. As of December 31, 2007, 29 of our rigs are working on properties that we operate; six of our rigs are drilling on a contract basis for third parties; three are being retrofitted and six are idle or being repaired.

In 2005 we placed an order for 22 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.

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 include 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 year ended December 31, 2007 was $107.6 million compared to $122.9 million in 2006. The 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.

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Prior to the NEG acquisition, transportation, treating and processing of gas for NEG was recorded as midstream gas services revenue. Operating income increased $3.3 million in 2007 to $6.8 million due to lower gas prices paid and an increase in marketing and transportation for our own account. 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.

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 our wholly-owned subsidiary, 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. 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.

We believe our tertiary oil recovery operations will provide significant long-term production growth potential at reasonable rates of return. Generally, 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. As a result, we do not anticipate that PetroSource will be profitable for the next several years.

Results of Operations

Year Ended December 31, 2007 Compared to the Year Ended December 31, 2006

Impact of the NEG Acquisition. The results of operations for the year ended December 31, 2006 include the results of NEG from November 21, 2006. The results of operations for the year ended December 31, 2007 include the NEG acquisition for the full year. While NEG was principally an exploration and production company, the acquisition affected several of our revenue and expense categories. Revenues and expenses related to our natural gas and crude oil operations increased due to increased production from the acquired NEG properties. Revenues and expenses relating to our drilling and services and midstream and marketing operations decreased due to increased intercompany eliminations as more services were provided on company-owned properties. General and administrative expenses increase due to the addition of new staff. Interest expense increased due to the additional borrowings incurred in conjunction with the NEG acquisition.

Revenue. Total revenue increased 75% to $677.5 million for the year ended December 31, 2007 from $388.2 million in 2006. This increase was due to a $376.4 million increase in natural gas and oil sales and was partially offset by lower revenues in our other segments.

	Year Ended December 31,			
	2007	2006	$ Change	% Change
		(In thousands)		

Revenue:				
Natural gas and crude oil	$ 477,612	$ 101,252	$ 376,360	371.7%
Drilling and services	73,197	139,049	(65,852)	(47.4)%
Midstream and marketing	107,765	122,896	(15,131)	(12.3)%
Other	18,878	25,045	(6,167)	(24.6)%
Total revenues	$ 677,452	$ 388,242	$ 289,210	74.5%

Total natural gas and crude oil revenues increased $376.4 million to $477.6 million for the year ended December 31, 2007, compared to $101.3 million in 2006, primarily as a result of an increase in natural gas and crude oil production volumes. Total natural gas production increased 287% to 51,958 Mmcf in 2007 compared to 13,410 Mmcf in 2006, while crude oil production increased 534% to 2,042 MBbls in 2007 from 322 MBbls in 2006. The increase was due to the NEG acquisition and our successful drilling in the WTO. The average price received for our natural gas and crude oil production increased 13% in 2007 to $7.45 per Mcfe compared to $6.60 per Mcfe in 2006, excluding the impact of derivative contracts.

Drilling and services revenue decreased 47% to $73.2 million in 2007 compared to $139.0 million 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 26.0 (average for the year ended December 31, 2007) in 2007 compared to 21.9 in 2006, an increase of 19%, and the average daily revenue per rig, after considering the effect of the elimination of intercompany usage, was essentially unchanged at $17,177 per day.

Midstream and marketing revenue decreased $15.1 million, or 12%, with revenues of $107.8 million for the year ended December 31, 2007, as compared to $122.9 million in 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 $18.9 million during 2007 from $25.0 million in 2006. The decrease was primarily due to the sale of various non-energy related assets to our former President and Chief Operating Officer. Revenues related to these assets are included in the 2006 period prior to their sale in August 2006. This decrease was slightly offset by an increase in revenues generated by our CO_2 operations.

Operating Costs and Expenses. Total operating costs and expenses increased to $490.6 million during 2007, compared to $351.3 million in 2006, primarily due to increases in our production-related costs as well as an increase in corporate staff. These increases were partially offset by decreases in costs attributable to our drilling and services and midstream and marketing operations as well as increased gains on derivative instruments.

	Year Ended December 31,			
	2007	2006	$ Change	% Change
	(In thousands)			
Operating costs and expenses:				
Production	$ 106,192	$ 35,149	$ 71,043	202.1%
Production taxes	19,557	4,654	14,903	320.2%
Drilling and services	44,211	98,436	(54,225)	(55.1)%
Midstream and marketing	94,253	115,076	(20,823)	(18.1)%
Depreciation, depletion, and amortization natural gas and crude oil	173,568	26,321	147,247	559.4%
Depreciation, depletion and amortization other	53,541	29,305	24,236	82.7%
General and administrative	61,780	55,634	6,146	11.0%
Gain on derivative instruments	(60,732)	(12,291)	(48,441)	(394.1)%
Gain on sale of assets	(1,777)	(1,023)	(754)	(73.7)%
Total operating costs and expenses	$ 490,593	$ 351,261	$ 139,332	39.7%

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 $71.0 million due to increased production from our 2007 drilling activity and the addition of the NEG properties. 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 $14.9 million, or 320%, to $19.6 million primarily due to increased gas production as a result of our 2007 drilling activity and the addition of the NEG properties in 2006.

Drilling and services and midstream and marketing expenses decreased 55% and 18% respectively, during 2007 as compared to 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 $173.6 million during 2007 from $26.3 million in 2006. Our DD&A per Mcfe increased $0.98 to $2.70 from $1.72 in 2006. The increase is primarily attributable to our 2007 capital expenditures and the NEG acquisition, which increased our depreciable properties by the purchase price plus future development costs and increased production. Our production increased 320% to 64.2 Bcfe from 15.3 Bcfe in 2006.

DD&A for our other assets consists primarily of depreciation of our drilling rigs, natural gas plants and other equipment. The $24.2 million increase in DD&A other was due primarily to our increased investments in rigs, other oilfield services equipment and midstream assets. During 2006 and 2007, capital expenditures for drilling rigs, other oilfield services equipment and midstream assets were $293 million on a combined basis. 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 11% to $61.8 million during 2007 from $55.6 million in 2006. The increase was principally attributable to a $17.3 million increase in corporate salaries and wages which was due to a significant increase in corporate and support staff. As of December 31, 2007 we had 2,227 employees as compared to 1,443 at December 31, 2006. The increase in corporate salaries and wages was partially offset by $4.6 million in capitalized general and administrative expenses, a $5.5 million decrease due to a legal settlement recorded in 2006 and a $1.6 million decrease in stock compensation expense. In accordance with the full-cost method of accounting, we capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. During 2006 we settled a legal dispute resulting in an additional loss on the settlement of $5.5 million. As part of a severance package for certain executive officers, the Board of Directors approved the acceleration of vesting of certain stock awards resulting in increased compensation expense recognized during 2006.

For the year ended December 31, 2007, we recorded a gain of $60.7 million ($26.2 million unrealized gain and $34.5 million realized gain) on our derivatives instruments compared to a $12.3 million gain ($1.9 million unrealized loss and $14.2 million realized gain) in 2006. During 2007, we selectively entered into natural gas swaps and basis swaps by capitalizing on what we perceived as spikes in the price of natural gas or favorable basis differences between the NYMEX price and natural gas prices at our principal West Texas pricing point of Waha Hub. Unrealized gains or losses on derivatives contracts represent the change in fair value of open derivatives positions during the period. The change in fair value is principally measured based on period end prices as compared to the contract price. The unrealized gain recorded during 2007 was attributable to a decrease in average natural gas prices at December 31, 2007 as compared to the average natural gas prices at the various contract dates.

Other Income (Expense). Total other expense increased to $107.1 million for the year ended December 31, 2007 from $15.1 million in 2006. The increase is reflected in the table below.

	Year Ended December 31,			
	2007	**2006**	**$ Change**	**% Change**
		(In thousands)		
Other income (expense):				
Interest income	$ 5,423	$ 1,109	$ 4,314	389.0%
Interest expense	(117,185)	(16,904)	(100,281)	593.2%
Minority interest	276	(296)	572	193.2%
Income from equity investments	4,372	967	3,405	352.1%
Total other expense	(107,114)	(15,124)	(91,990)	(608.2)%
Income before income taxes	79,745	21,857	57,888	264.8%
Income tax expense	29,524	6,236	23,288	373.4%
Net income	$ 50,221	$ 15,621	$ 34,600	221.5%

Interest income increased to $5.4 million in 2007 from $1.1 million in 2006. This increase was due to interest income from investment of excess cash after the repayment of debt.

Interest expense increased to $117.2 million during 2007, from $16.9 million 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 had 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 term loan and sold 17.8 million shares of common stock in a private placement. A portion of the proceeds from the senior unsecured term loan was used to repay the bridge loan. Please read Liquidity and Capital Resources.

The minority interest is derived from Cholla Pipeline, LP, Sagebrush Pipeline, LLC and Integra. We acquired the remaining minority interest in Integra in the fourth quarter of 2007.

During the year ended December 31, 2007 we reported income from equity investments of $4.4 million as compared to $1.0 million in 2006. Approximately $1.9 million of the increase was attributable to income from our interest in the Grey Ranch processing plant which has experienced increased profitability due to higher levels of utilization in 2007 as compared to 2006. Approximately $1.5 million of the increase was attributable to income from Larclay as all of Larclay s rigs have now been delivered and all but one rig are operational.

We reported an income tax expense of $29.5 million for the year ended December 31, 2007 as compared to an expense of $6.2 million in 2006. The current period income tax expense represents an effective income tax rate of 37.0% as compared to 28.5% in 2006. The lower effective income tax rate in 2006 was attributable to favorable percentage depletion deductions during that period.

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

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,			
	2006	2005	$ Change	% Change
	(In thousands)			
Revenue:				
Natural gas and crude oil	$ 101,252	$ 49,987	$ 51,265	102.6%
Drilling and services	139,049	80,343	58,706	73.1%
Midstream and marketing	122,896	147,133	(24,237)	(16.5)%
Other	25,045	10,230	14,815	144.8%
Total revenues	$ 388,242	$ 287,693	$ 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 a shopping center that was sold in 2006.

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.

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	Year Ended December 31, 2006	2005	$ Change	% Change
		(In thousands)		
Operating costs and expenses:				
Production	$ 35,149	$ 16,195	$ 18,954	117.0%
Production taxes	4,654	3,158	1,496	47.4%
Drilling and services	98,436	52,122	46,314	88.9%
Midstream and marketing	115,076	141,372	(26,296)	(18.6)%
Depreciation, depletion and amortization-natural gas and oil	26,321	9,313	17,008	182.6%
Depreciation, depletion and amortization-other	29,305	14,893	14,412	96.8%
General and administrative	55,634	11,908	43,726	367.2%
Loss (gain) on derivative instruments	(12,291)	4,132	(16,423)	(397.5)%
Loss (gain) on sale of assets	(1,023)	547	(1,570)	(287.0)%
Total operating costs and expenses	$ 351,261	$ 253,640	$ 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 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 natural gas that we market and a decrease in natural 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 37% increase in DD&A per unit of production. The average DD&A per Mcfe was $1.68 for the year ended December 31, 2006 as compared to $1.23 in 2005. The increase in the DD&A rate was attributable to the NEG acquisition which added significantly higher reserves at a higher cost per Mcfe.

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

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

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 enter into collars and fixed-price swaps to mitigate the effect of price fluctuations of natural gas and oil. We use 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. Offsetting the 2006 net realized gain on the settlement or early termination of our derivative

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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 detailed in the table below.

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

Liquidity and Capital Resources

Summary

Our operating cash flow is influenced mainly by the prices 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.

On November 9, 2007, we completed the initial public offering of our common stock. The Company sold 32,379,500 shares of SandRidge common stock, including 4,170,000 shares sold directly to an entity controlled by Tom L. Ward. The shares were sold at a price of $26 per share. After deducting underwriting discounts of approximately $44.0 million and offering expenses of $3.1 million, the Company received net proceeds of approximately $794.7 million. The net proceeds were utilized as follows (in millions):

Repayment of outstanding balance and accrued interest on senior credit facility	$ 515.9
Repayment of note payable and accrued interest incurred in connection with recent acquisition	49.1
Excess cash to fund capital expenditures	229.7
Total	$ 794.7

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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 December 31, 2007, our cash and cash equivalents were $63.1 million, and we had approximately $677.3 million available under our senior credit facility. The cash balance at December 31, 2007 was the result of the remaining proceeds from our initial public offering described above. As of December 31, 2007, we had no amounts outstanding under our senior credit facility, and $1.1 billion in total debt outstanding.

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 and availability under our senior credit facility will be sufficient to meet our capital expenditure budget for the next twelve months.

Our capital expenditures by segment were:

	Year Ended December 31,		
	2007	**2006**	**2005**
		(In thousands)	
Capital Expenditures:			
Exploration and production	$ 1,046,552	$ 170,872	$ 61,227
Drilling and oil field services	123,232	89,810	43,730
Midstream gas services	63,828	16,975	25,904
Other	47,236	28,884	3,735
Capital expenditures, excluding acquisitions	1,280,848	306,541	134,596
Acquisitions	116,650	1,054,075	21,247
Total	$ 1,397,498	$ 1,360,616	$ 155,843

We estimate that our total capital expenditures for 2008, excluding acquisitions, will be approximately $1.25 billion. Our planned 2008 capital expenditures are consistent with 2007 levels. As in 2007, our 2008 capital expenditures for our exploration and production segment will be focused on growing and developing our reserves and production on our existing acreage and acquiring additional acreage, primarily in the WTO. Of our total $1.25 billion capital expenditure budget, approximately $1.1 billion is budgeted for exploration and production activities. Included in our 2008 exploration and production capital expenditure budget is $622 million for drilling in the WTO, including the Piñon field, $285 million for drilling in areas other than the WTO, $33 million for PetroSource and $194 million for land and seismic. Based on encouraging initial results from our 3-D seismic acquisition program that we commenced in 2007, we have budgeted $151 million of our 2008 WTO capital expenditures to explore for new fields within the WTO. We plan to drill approximately 440 gross wells in 2008.

During 2008 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 three of these rigs, which we expect to join our fleet during the first half of 2008. We are also continuing to upgrade and modernize our rig fleet. Approximately $52 million of our 2008 capital expenditure budget will be spent on our drilling and oil field services segment.

We anticipate spending approximately $107 million in capital expenditures in our midstream gas services and other segments as we aggressively expand our network of gas gathering lines and plant and compression capacity.

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.

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Cash Flows from Continuing Operations

Our cash flows from continuing operations are as follows:

	Year Ended December 31,		
	2007	2006	2005
		(In thousands)	
Cash Flows from Operations:			
Cash flows provided by operating activities	$ 357,452	$ 67,349	$ 63,297
Cash flows used in investing activities	(1,385,581)	(1,340,567)	(155,826)
Cash flows provided by financing activities	1,052,316	1,266,435	126,413
Net increase (decrease) in cash and cash equivalents	$ 24,187	$ (6,783)	$ 33,884

Operating Activities. Net cash provided by operating activities for the years ended December 31, 2007 and 2006 were $357.5 million and $67.3 million, respectively. The increase in cash provided by operating activities from 2006 to 2007 was primarily due to our $34.6 million increase in net income as a result of our 320% increase in production volumes as a result of the NEG and various other acquisitions as well as our drilling success. Also, contributing to this increase was $34.5 million in realized gains on our derivative contracts. These increases were partially offset by increases in general and administrative costs such as salaries and wages.

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

Investing Activities. Cash flows used in investing activities increased to $1,385.6 million during 2007 from $1,340.6 million in 2006. During 2006, we acquired NEG for $990.4 million, net of cash received and $231.2 million in common stock. Capital expenditures for property plant and equipment during 2007 were $1,280.8 million as compared to $306.5 million in 2006 as we continued to ramp up our capital expenditure program. During 2007 our capital expenditures were $1,046.6 million in our exploration and production segment, $123.2 million for drilling and oil field services, $63.8 million for midstream gas services and $47.2 million for other capital expenditures.

Cash flows used in investing activities increased to $1,340.6 million for the year ended December 31, 2006 from $155.8 million in 2005. 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, 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, 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.

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. During 2007 we raised $1.1 billion in equity issuances and had net cash repayments of $0.7 million of debt. Our equity issuances included the November 2007 initial public offering of our common stock yielding net proceeds of $794.7 million and a March 2007 private placement of our common stock which provided net proceeds of approximately $318.7 million. Proceeds from borrowings were $1,331.5 million during 2007 and we repaid approximately $1,332.2 million leaving net cash repayments during 2007 of approximately $0.7 million. We used the net proceeds from our term loan and the common stock issuances to repay our senior bridge facility and all of the outstanding borrowings under our senior credit facility. Our financing activities provided $1,052.3 million in cash during 2007 compared to $1,266.4 million in 2006.

During the year ended December 31, 2006, we incurred net borrowings of $743.0 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. Most of our borrowings in 2005 funded the acquisition of 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 common stock, which was primarily used to reduce outstanding borrowings and to increase our interest in PetroSource.

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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. The senior credit facility matures on November 21, 2011.

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

The senior credit facility contains various covenants that limit our and certain of our subsidiaries ability to grant certain liens; make certain loans and investments; make distributions; redeem stock; redeem or prepay debt; merge or consolidate with or into a third-party; or engage in certain asset dispositions, including a sale of all or substantially all of our assets. Additionally, the senior credit facility limits our and certain of our subsidiaries ability to incur additional indebtedness.

The senior credit facility also contains financial covenants, including maintenance of agreed upon levels for (i) the ratio of 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) the 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 four completed fiscal quarters and (iii) the current ratio, which must be at least 1.0:1.0. As of December 31, 2007, we were in compliance with these financial covenants.

The obligations under the senior credit facility are secured by first priority liens on all shares of capital stock of each of our present and future subsidiaries; all intercompany debt of us and our subsidiaries; and substantially all of our assets and the assets of our guarantor subsidiaries, including proved natural gas and oil reserves representing at least 80% of the present discounted value (as defined in the senior credit facility) of our proved 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 are 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 requires approval by the facility lenders. The borrowing base is subject to review semi-annually; however, the lenders reserve the right to have one additional redetermination of the borrowing base per calendar year. Unscheduled redeterminations may be made at our request, but are limited to one request per year.

The borrowing base is determined based on proved developed producing reserves, proved developed non-producing reserves and proved undeveloped reserves and was $700 million as of December 31, 2007. We repaid all outstanding borrowings under this facility on November 9, 2007, and as of December 31, 2007, there were $22.7 million in letters of credit and no principal amounts outstanding under the senior credit facility. Subsequent to December 31, 2007, we began drawing on our senior credit facility to partially fund our 2008 capital expenditure program. As of February 22, 2008 the outstanding balance under our senior credit facility was $155 million, and including outstanding letters of credit of $22.7 million, the available balance under our senior credit facility was $522.3 million.

At our election, interest under the senior credit facility is determined by reference to (i) 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 is 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 is paid at the end of each three-month period. The average interest rate paid on amounts outstanding under our senior credit facility for the year ended December 31, 2007 was 7.34%.

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

We issued $350 million at a variable rate with interest payable quarterly and principal due on April 1, 2014 (the Variable Rate Term Loans). The Variable Rate Term Loans bear interest, at our option, at LIBOR plus 3.625% or the higher of (i) the federal funds rate, as defined, plus 3.125% or (ii) a bank s prime rate plus 2.625%. After April 1, 2009 the Variable Rate Term Loans may be prepaid in whole or in part with a prepayment penalty. The average interest rates paid on amounts outstanding under our variable rate term loans during 2007 was 8.94%. In January 2008, we entered into a $350 million notional amount interest rate swap agreement with a financial institution that effectively fixed our interest rate on the Variable Rate Term Loans at 6.2625% for the period from April 1, 2008 through April 1, 2011.

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

After March 22, 2008, but not later than April 30, 2008, we are required to offer to exchange the senior term loans for senior unsecured notes with registration rights. The senior unsecured notes will have substantially similar terms and conditions as the senior term loans. If the exchange does not occur by May 31, 2008, the interest rate on the senior term loans will increase by 0.25% every 90 days up to a maximum of 0.50%. Debt covenants under the senior term loans include financial covenants similar to those of the senior credit facility and include limitations on the incurrence of indebtedness, payment of dividends, asset sales, certain asset purchases, transactions with related parties, and consolidation or merger agreements. We incurred $26.1 million of debt issuance costs in connection with the senior term loans. These costs are included in other assets and amortized over the term of the senior term loans.

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 December 31, 2007, the aggregate outstanding balance of these notes was $47.8 million, with annual fixed interest rates ranging from 7.64% to 8.87%. The notes have a final maturity date of December 1, 2011, require 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.

On November 15, 2007, we entered into a $20 million note payable which is fully secured by one of the buildings and a parking garage located on our property in downtown Oklahoma City, Oklahoma which we purchased in July 2007. The mortgage bears interest at 6.08% per annum, and matures November 15, 2022. Payments of principal and interest in the amount of approximately $0.5 million are due on a quarterly basis through the maturity date.

We have financed the purchase of other equipment used in our business. At December 31, 2006, the aggregate outstanding balance of these financings was $4.5 million. We repaid such borrowings during 2007 with borrowings under our senior credit facility.

In 2007 we also repaid $4.0 million in secured borrowings incurred in 2005 for the purpose of completing our gas processing plant and pipeline in Colorado.

Senior Bridge Facility. On November 21, 2006, we entered into an $850 million senior unsecured bridge facility (the senior bridge facility). This facility was repaid in full in March 2007 with proceeds from our senior unsecured term loans.

Prior Senior Credit Facility. On November 21, 2006, we replaced a $130 million revolving credit facility with our current senior credit facility. 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 2,184,286 shares of convertible preferred stock issued and outstanding. Each holder of our convertible preferred stock is entitled to quarterly cash dividends at the annual rate of 7.75% of the accreted value of its convertible preferred stock. During 2007 we paid cash dividends of $33.3 million. 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 was $210 per share as of December 31, 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

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anti-dilution adjustments. Beginning in the second quarter of 2008, we may convert all outstanding shares of convertible preferred stock at the then current conversion rate subject to the satisfaction of certain conditions.

Contractual Obligations

A summary of our contractual obligations as of December 31, 2007 is provided in the following table:

	Payments Due by Year (In thousands)						
	2008	**2009**	**2010**	**2011**	**2012**	**After 2012**	**Total**
Long-term debt	$ 15,350	$ 16,580	$ 12,476	$ 7,222	$ 1,052	$ 1,014,969	$ 1,067,649
Interest on term loans(1)	92,868	91,580	90,322	89,510	89,219	172,020	625,519
Firm transportation(2)	1,597	1,597	1,597	1,597	1,597	6,775	14,760
Operating leases	2,139	1,102	110	110	46		3,507
Third-party drilling rig commitments(3)	12,803						12,803
Dispute settlement payments(4)	5,000	5,000	5,000	5,000			20,000
Asset retirement obligations	864	365		7,822	444	49,085	58,580
Total	$ 130,621	$ 116,224	$ 109,505	$ 111,261	$ 92,358	$ 1,242,849	$ 1,802,818

(1) Based on interest rates as of December 31, 2007.

(2) We entered into a firm transportation agreement with Questar Pipeline Company giving us guaranteed capacity on its 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 representing bank trust and escrow accounts required by surety bond underwriters and certain former owners of NEG s offshore properties. In accordance with requirements of the U.S Department of Interior s Mineral Management Service, NEG 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.

During 2007, funds totaling $10.3 million were released from escrow accounts and returned to us.

In connection with one of the escrow accounts, we are required to make quarterly deposits to the escrow accounts of $0.8 million up to a maximum of $14.0 million. Payments to the escrow account are estimated as follows (in thousands):

2008	$ 3,200
2009	3,200
2010	2,586
	$ 8,986

Additionally, two of the escrow accounts require us to deposit additional funds in an escrow account equal to 10% of the net proceeds, as defined, from certain of our offshore properties. During 2007 we deposited approximately $5.8 million in the escrow accounts.

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 Item 8.

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Consolidated Financial Statements and Supplementary Data, Note 1 Summary of Organization and Significant Accounting Policies included in Exhibit I 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. 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, 2007, 2006 and 2005, we revised our proved reserves upward from prior years reports by approximately 351.6 Bcfe, 26.6 Bcfe and 12.3 Bcfe, respectively 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 costs 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 ranges 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.

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New Accounting Pronouncements

For a discussion of recently adopted accounting standards, see Note 1 to our consolidated financial statements included in Exhibit I.

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 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.

CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

Various statements contained in this report, 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 Annual Report on Form 10-K speak only as of the date of this annual Report on Form 10-K; 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 in Item 1A- Risk Factors including the following:

- the volatility of natural gas and oil prices;
- uncertainties in estimating natural gas and oil reserves;
- the need to replace the natural gas and oil reserves we produce;
- our ability to execute our growth strategy by drilling wells as planned;
- the need to drill productive, economically viable natural gas and oil wells;
- risks and liabilities associated with acquired properties;

amount, nature and timing of capital expenditures, including future development costs, required to develop the WTO;

concentration of operations in the WTO;

economic viability of WTO production with high CO_2 content;

availability of natural gas production for our midstream services operations;

limitations of seismic data;

risks associated with drilling natural gas and oil wells;

availability of satisfactory natural gas and oil marketing and transportation;

availability and terms of capital;

substantial existing indebtedness;

limitations on operations resulting from debt restrictions and financial covenants;

potential financial losses or earnings reductions from commodity derivatives;

competition in the natural gas and oil industry;

costs to comply with current and future governmental regulation of the natural gas and oil industry, including environmental, health and safety laws and regulations; and

the need to maintain adequate internal control over financial reporting.

Item 7A. *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 natural 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 natural 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 commodity-based derivative instruments, including collars, fixed-price swaps and basis protection swaps. These transactions generally require no cash payment upfront and are settled in cash at maturity. While our derivative strategy may result in lower operating profits than if we were not party to these derivative instruments in times of high natural gas prices, we believe that the stabilization of prices and protection afforded us by providing a revenue floor for our production is very beneficial.

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

While we believe that the gas and oil price derivative arrangements we enter into are important to our program to manage price variability for our production, we have not designated any of our derivative contracts as hedges for accounting purposes. We record all derivative contracts on the balance sheet at fair value, which will be significantly affected by changes in gas and oil prices. We establish fair value of our derivative contracts by market price quotations of the derivative contract or, if not available, market price quotations of derivative contracts with similar terms and characteristics. When market quotations are not available, we will estimate the fair value of derivative contracts using option pricing models that management believes represent its best estimate. Changes in fair values of our derivative contracts that are not designated as hedges for accounting purposes are recognized as unrealized gains and losses in current period earnings. As a result, our 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 years ended December 31, 2007 and 2006 was $60.7 million and $12.3 million, respectively. For the year ended December 31, 2005, we recognized a loss of $4.1 million.

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

Period	Commodity	Notional Volume	Weighted Avg. Fixed Price
Fixed price swaps:			
November 2007 March 2008	Natural gas	1,520,000 MmBtu	$ 8.51
November 2007 June 2008	Natural gas	4,860,000 MmBtu	$ 8.05
November 2007 June 2008	Natural gas	9,720,000 MmBtu	$ 8.20
January 2008	Natural gas	310,000 MmBtu	$ 8.24
January 2008 June 2008	Natural gas	3,640,000 MmBtu	$ 7.99
January 2008 June 2008	Natural gas	3,640,000 MmBtu	$ 7.99
January 2008 December 2008	Natural gas	3,660,000 MmBtu	$ 8.23
January 2008 December 2008	Natural gas	3,660,000 MmBtu	$ 8.48

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Period	Commodity	Notional Volume	Weighted Avg. Fixed Price
January 2008 December 2008	Natural gas	3,660,000 MmBtu	$ 9.00
April 2008 June 2008	Natural gas	910,000 MmBtu	$ 7.17
May 2008 August 2008	Natural gas	2,460,000 MmBtu	$ 8.38
July 2008	Natural gas	310,000 MmBtu	$ 8.00
July 2008	Natural gas	310,000 MmBtu	$ 8.02
July 2008 September 2008	Natural gas	920,000 MmBtu	$ 7.43
July 2008 September 2008	Natural gas	920,000 MmBtu	$ 7.49
July 2008 September 2008	Natural gas	920,000 MmBtu	$ 8.06
July 2008 September 2008	Natural gas	920,000 MmBtu	$ 8.07
July 2008 September 2008	Natural gas	920,000 MmBtu	$ 8.23
July 2008 September 2008	Natural gas	920,000 MmBtu	$ 8.36
July 2008 December 2008	Natural gas	1,840,000 MmBtu	$ 8.31
July 2008 December 2008	Natural gas	1,840,000 MmBtu	$ 8.59
August 2008	Natural gas	310,000 MmBtu	$ 8.00
August 2008	Natural gas	310,000 MmBtu	$ 8.07
September 2008	Natural gas	300,000 MmBtu	$ 8.05
September 2008	Natural gas	300,000 MmBtu	$ 8.10
October 2008 December 2008	Natural gas	920,000 MmBtu	$ 7.96
October 2008 December 2008	Natural gas	1,840,000 MmBtu	$ 8.00
October 2008 December 2008	Natural gas	920,000 MmBtu	$ 8.07
October 2008 December 2008	Natural gas	920,000 MmBtu	$ 8.11
October 2008 December 2008	Natural gas	920,000 MmBtu	$ 8.16
October 2008 December 2008	Natural gas	920,000 MmBtu	$ 8.32
October 2008 December 2008	Natural gas	920,000 MmBtu	$ 8.83
January 2009 March 2009	Natural gas	900,000 MmBtu	$ 8.56
January 2009 March 2009	Natural gas	900,000 MmBtu	$ 8.60
January 2009 March 2009	Natural gas	900,000 MmBtu	$ 8.65
January 2009 March 2009	Natural gas	900,000 MmBtu	$ 8.91
Collars:			
January 2008 June 2008	Crude oil	42,000 Bbls	$ 50.00 - $83.35
July 2008 December 2008	Crude oil	54,000 Bbls	$ 50.00 - $82.60
Waha basis swaps:			
January 2008 December 2008	Natural gas	10,980,000 MmBtu	$ (0.57)
January 2008 December 2008	Natural gas	7,320,000 MmBtu	$ (0.585)
January 2008 December 2008	Natural gas	7,320,000 MmBtu	$ (0.59)
January 2008 December 2008	Natural gas	3,660,000 MmBtu	$ (0.595)
January 2008 December 2008	Natural gas	3,660,000 MmBtu	$ (0.625)
January 2008 December 2008	Natural gas	7,320,000 MmBtu	$ (0.635)
January 2008 December 2008	Natural gas	7,320,000 MmBtu	$ (0.6525)
May 2008 August 2008	Natural gas	2,460,000 MmBtu	$ (0.45)
June 2008 August 2008	Natural gas	920,000 MmBtu	$ (0.4808)
September 2008 December 2008	Natural gas	2,440,000 MmBtu	$ (0.7930)
January 2009 December 2009	Natural gas	3,650,000 MmBtu	$ (0.47)
January 2009 December 2009	Natural gas	3,650,000 MmBtu	$ (0.49)
January 2009 December 2009	Natural gas	3,650,000 MmBtu	$ (0.4975)

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These derivatives have not been designated as hedges and the Company records all derivatives on the balance sheet at fair value. Changes in derivative fair values are recognized in earnings. Cash settlements and valuation gains and losses are included in (gain) loss on derivative contracts in the consolidated statements of operations. The following summarizes the cash settlements and valuation gains and losses for the years ended December 31, 2007, 2006 and 2005 (in thousands):

	2007	2006	2005
Realized (gain) loss	$ (34,494)	$ (14,169)	$ 2,836
Unrealized (gain) loss	(26,238)	1,878	1,296
(Gain) loss on derivative contracts	$ (60,732)	$ (12,291)	$ 4,132

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 notes payable related to our drilling rig fleet and related oil field services equipment, Sagebrush Pipeline, insurance financing, and other equipment and vehicles and a portion of our senior term loans 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 varies as interest rates change.

Borrowings under our senior credit facility and a portion of our senior term loans 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. Based on the approximately $350.0 million outstanding balance of the variable rate portion of our senior term loans at December 31, 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 $3.5 million for the year ended December 31, 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 December 31, 2007, we were not party to any interest rate swap instruments. In January 2008, we entered into a $350 million notional amount interest rate swap agreement with a financial institution that effectively fixed our interest rate on the Variable Rate Term Loans at 6.2625% for the period from April 1, 2008 through April 1, 2011.

Item 8. *Financial Statements and Supplementary Data*

Our consolidated financial statements required by this item are included in this report beginning on page F-1.

Item 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*

Not applicable.

Item 9A. *Controls and Procedures*

Evaluation of Disclosure Controls and Procedures

We performed an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rules 13a-15 and 15d-15 as of the end of the period covered by this report. Based upon that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures were effective to provide reasonable assurance that the information required to be disclosed by us in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission and such information is accumulated and communicated to management as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended December 31, 2007 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

This annual report on Form 10-K does not include a report of management s assessment regarding internal control over financial reporting or an attestation report of the Company s registered public accounting firm due to a transition period established by rules of the Securities and Exchange Commission for newly public companies.

Item 9B. ***Other Information***

Not applicable.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

The information required by this item is incorporated herein by reference to our definitive proxy statement, which will be filed no later than April 29, 2008.

Item 11. ***Executive Compensation***

The information required by this item is incorporated herein by reference to our definitive proxy statement, which will be filed no later than April 29, 2008.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

The information required by this item is incorporated herein by reference to our definitive proxy statement, which will be filed no later than April 29, 2008.

Item 13. ***Certain Relationships and Related Transactions and Director Independence***

The information required by this item is incorporated herein by reference to our definitive proxy statement, which will be filed no later than April 29, 2008.

Item 14. ***Principal Accountant Fees and Services***

The information required by this item is incorporated herein by reference to our definitive proxy statement, which will be filed no later than April 29, 2008.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

The following documents are filed as a part of this report:

(1) *Consolidated Financial Statements*

Reference is made to the Index to Consolidated Financial Statements appearing on page F-1.

(2) *Financial Statement Schedules*

All financial statement schedules have been omitted because they are not applicable or the required information is presented in the consolidated financial statements or notes thereto.

(3) *Exhibits*

See Exhibit Index for a description of the exhibits filed as a part of this report.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, changes in stockholders equity and of cash flows present fairly, in all material respects, the financial position of SandRidge Energy, Inc. and its subsidiaries at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 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.

PricewaterhouseCoopers LLP

Houston, Texas
March 7, 2008

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SandRidge Energy, Inc. and Subsidiaries

Consolidated Balance Sheets

	As of December 31, 2007	As of December 31, 2006
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 63,135	$ 38,948
Accounts receivable, net:		
Trade	94,741	89,774
Related parties	20,018	5,731
Derivative contracts	21,958	
Inventories	3,993	2,544
Deferred income taxes	1,820	6,315
Other current assets	20,787	31,494
Total current assets	226,452	174,806
Oil and natural gas properties, using full cost method of accounting		
Proved	2,848,531	1,636,832
Unproved	259,610	282,374
Less: accumulated depreciation and depletion	(230,974)	(60,752)
	2,877,167	1,858,454
Other property, plant and equipment, net	460,243	276,264
Derivative contracts	270	
Investments	7,956	3,584
Restricted deposits	31,660	33,189
Other assets	26,818	42,087
Total assets	$ 3,630,566	$ 2,388,384
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Current maturities of long-term debt	$ 15,350	$ 26,201
Accounts payable and accrued expenses:		
Trade	215,497	129,799
Related parties	395	1,834
Asset retirement obligation	864	
Derivative contracts		958
Total current liabilities	232,106	158,792
Long-term debt	1,052,299	1,040,630
Derivative contracts		3,052

Other long-term obligations	16,817	21,219
Asset retirement obligation	57,716	45,216
Deferred income taxes	49,350	24,922
Total liabilities	1,408,288	1,293,831
Commitments and contingencies (Note 16)		
Minority interest	4,672	5,092
Redeemable convertible preferred stock, $0.001 par value, 2,625 shares authorized, 2,184 and 2,137 shares issued and outstanding at December 31, 2007 and 2006, respectively	450,715	439,643
Stockholders equity:		
Preferred stock, $0.001 par value; 47,375 shares authorized; no shares issued and outstanding in 2007 and 2006		
Common stock, $0.001 par value, 400,000 shares authorized; 141,847 issued and 140,391 outstanding at December 31, 2007 and 93,048 issued and 91,604 outstanding at December 31, 2006	140	92
Additional paid-in capital	1,686,113	574,868
Treasury stock, at cost	(18,578)	(17,835)
Retained earnings	99,216	92,693
Total stockholders equity	1,766,891	649,818
Total liabilities and stockholders equity	$ 3,630,566	$ 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, 2007	2006	2005
	(In thousands, except per share amounts)		
Revenues:			
Natural gas and crude oil	$ 477,612	$ 101,252	$ 49,987
Drilling and services	73,197	139,049	80,343
Midstream and marketing	107,765	122,896	147,133
Other	18,878	25,045	10,230
Total revenues	677,452	388,242	287,693
Expenses:			
Production	106,192	35,149	16,195
Production taxes	19,557	4,654	3,158
Drilling and services	44,211	98,436	52,122
Midstream and marketing	94,253	115,076	141,372
Depreciation, depletion and amortization natural gas and crude oil	173,568	26,321	9,313
Depreciation, depletion and amortization other	53,541	29,305	14,893
General and administrative	61,780	55,634	11,908
(Gain) loss on derivative contracts	(60,732)	(12,291)	4,132
(Gain) loss on sale of assets	(1,777)	(1,023)	547
Total expenses	490,593	351,261	253,640
Income from operations	186,859	36,981	34,053
Other income (expense):			
Interest income	5,423	1,109	206
Interest expense	(117,185)	(16,904)	(5,277)
Minority interest	276	(296)	(737)
Income (loss) from equity investments	4,372	967	(384)
Total other income (expense)	(107,114)	(15,124)	(6,192)
Income before income tax expense	79,745	21,857	27,861
Income tax expense	29,524	6,236	9,968
Income from continuing operations	50,221	15,621	17,893
Income from discontinued operations (net of tax expense of $118 in 2005)			229
Net income	50,221	15,621	18,122
Preferred stock dividends and accretion	39,888	3,967	

Income available to common stockholders	10,333	$ 11,654	$ 18,122
Basic and Diluted Earnings Per Share:			
Income from continuing operations	$ 0.46	$ 0.21	$ 0.31
Income from discontinued operations, net of income tax			0.01
Preferred dividends	(0.37)	(0.05)	
Basic and diluted income per share available to common stockholders	$ 0.09	$ 0.16	$ 0.32
Weighted average number of common shares outstanding:			
Basic	108,828	73,727	56,559
Diluted	110,041	74,664	56,737

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
				(In thousands)			
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 costs		6	97,427				97,433
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
		50	1,113,314				1,113,364

Stock offerings, net of $4.5 million in offering costs							
Conversion of common stock to redeemable convertible preferred stock		(1)	(9,650)				(9,651)
Accretion on redeemable convertible preferred stock						(1,421)	(1,421)
Purchase of treasury stock		(1)			(1,660)		(1,661)
Common stock issued under retirement plan			379		917		1,296
Stock-based compensation			7,202				7,202
Net income						50,221	50,221
Redeemable convertible preferred stock dividend						(42,277)	(42,277)
Balance, December 31, 2007	$	$ 140	$ 1,686,113	$	$ (18,578)	$ 99,216	$ 1,766,891

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,		
	2007	2006	2005
	(In thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 50,221	$ 15,621	$ 18,122
Income from discontinued operations, net of tax			229
Income from continuing operations	50,221	15,621	17,893
Adjustments to reconcile net income to net cash provided by operating activities:			
Provision for doubtful accounts		2,528	33
Depreciation, depletion and amortization	227,109	55,626	24,206
Debt issuance cost amortization	15,998	299	
Deferred income taxes	28,923	348	9,460
Provision for inventory obsolescence	203		
Unrealized (gain) loss on derivatives	(26,238)	1,878	1,296
(Income) loss on sale of assets	(1,777)	(1,023)	547
Interest income restricted deposits	(1,354)	(151)	
(Gain) loss from equity investments, net of distributions	(4,372)	(956)	846
Stock-based compensation	7,202	8,792	481
Minority interest	(276)	296	737
Changes in operating assets and liabilities increasing (decreasing) cash:			
Receivables	(19,061)	(2,648)	(25,494)
Inventories	(1,730)	(938)	(46)
Other current assets	12,374	(22,238)	(1,146)
Other assets and liabilities, net	(5,069)	(2,131)	775
Accounts payable and accrued expenses	75,299	12,046	33,709
Net cash provided by operating activities by continuing operations	357,452	67,349	63,297
Net cash provided by operating activities by discontinued operations			347
Net cash provided by operating activities	357,452	67,349	63,644
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures for property, plant and equipment	(1,280,848)	(306,541)	(134,596)
Acquisitions of assets, net of cash received of $0, $21,100 and $66	(116,650)	(1,054,075)	(21,247)
Proceeds from sale of assets	9,034	19,742	3,327
Proceeds from sale of investments		2,373	413
Contributions on equity investments		(3,388)	(1,350)
Refunds of restricted deposits	10,328		
Fundings of restricted deposits	(7,445)	(1,051)	
Restricted cash		2,373	(2,373)

Net cash used in investing activities for continuing operations	(1,385,581)	(1,340,567)	(155,826)
Net cash used in investing activities for discontinued operations			(1,473)
Net cash used in investing activities	(1,385,581)	(1,340,567)	(157,299)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	1,331,541	1,261,910	247,460
Repayments of borrowings	(1,332,219)	(518,870)	(301,285)
Dividends paid-preferred	(33,321)		(1)
Minority interests contributions (distributions)	(144)	(618)	7,117
Proceeds from issuance of common stock	1,114,660	100,776	173,122
Proceeds from issuance of redeemable convertible preferred stock		439,486	
Purchase of treasury shares	(1,661)	(500)	
Debt issuance costs	(26,540)	(15,749)	
Net cash provided by financing activities for continuing operations	1,052,316	1,266,435	126,413
Net cash provided by financing activities for discontinued operations			
Net cash provided by financing activities	1,052,316	1,266,435	126,413
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	24,187	(6,783)	32,758
CASH AND CASH EQUIVALENTS, beginning of year	38,948	45,731	12,973
CASH AND CASH EQUIVALENTS, end of year	$ 63,135	$ 38,948	$ 45,731
Supplemental Disclosure of Cash Flow Information:			
Cash paid for interest, net of amounts capitalized	$ 83,567	$ 15,079	$ 7,222
Cash paid for income taxes	2,371	1,599	
Supplemental Disclosure of Noncash Investing and Financing Activities:			
Redeemable convertible preferred stock dividends, net of dividends paid	$ 8,956	$	$
Insurance premium financed	1,496	5,023	2,133
Accretion on redeemable convertible preferred stock	1,421	157	
Common stock issued in connection with acquisitions		236,284	55,285
Assumption of restricted deposits and notes payable in connection with acquisition		313,628	
Assets disposed in exchange for common stock			17,335

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

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, Gulf Coast area, the Gulf of Mexico, Oklahoma, and the Piceance Basin in Colorado.

On November 21, 2006, the Company acquired all of the outstanding membership interests of NEG Oil & Gas LLC (NEG) (See Note 2).

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.

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 costs and other factors. These revisions may be material and could materially affect the Company s future depletion, depreciation and amortization expenses.

The Company s revenue, profitability, and future growth are substantially dependent upon the prevailing and future prices for oil and natural gas, which are dependent upon numerous factors beyond its control such as economic, regulatory developments and competition from other energy sources. The energy markets have historically been volatile and there can be no assurance that oil and natural gas prices will not be subject to wide fluctuations in the future. A substantial or extended decline in oil and natural gas prices could have a 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. 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.

Debt Issue Costs. The Company amortizes debt issue costs related to its senior credit facility, senior bridge facility and term loans as interest expense over the scheduled maturity period of the debt. Unamortized debt issuance costs were approximately $26.0 million as of December 31, 2007 and approximately $15.5 million as of December 31, 2006. The Company includes those unamortized costs in other assets.

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Continued)

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 has recorded a liability for gas imbalance positions related to gas properties with insufficient proved reserves of $1.6 million and $0.9 million at December 31, 2007 and 2006, respectively. 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, because 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 ranges 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 turnkey contracts that 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.

Revenues from the midstream services segment are derived from providing gathering, compression, treating, processing, 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, 2007 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. During 2007, the Company capitalized internal costs and interest expenses of $4.6 million and $0.3 million, respectively, to the full cost pool. No internal costs or interest expense was capitalized to the full cost pool in 2006 or 2005.

Capitalized 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 plus future development costs 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.

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Continued)

Under full cost accounting, total capitalized costs of natural gas and oil properties (net of accumulated depreciation, depletion and amortization) less related deferred income 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-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 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 or abandonment of wells are included in the computation of the discounted present value of future net revenues for 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.

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

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Continued)

their estimated present value at the asset s inception, with the offsetting increase to property cost. Periodic accretion expense of the estimated liability is recorded in the statements of operations.

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 its 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).

	2007	2006	2005
Asset retirement obligation, January 1	$ 45,216	$ 6,979	$ 4,394
Liability incurred upon acquiring and drilling wells	3,265	2,996	2,779
NEG acquisition		40,343	
Revisions in estimated cash flows	5,971	(5,700)	
Liability settled in current period	(9)		(512)
Accretion of discount expense	4,137	598	318
Asset retirement obligation, December 31	58,580	45,216	6,979
Less: current portion	864		
Asset retirement obligation, net of current	$ 57,716	$ 45,216	$ 6,979

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.

The Company accounts for uncertain tax positions in accordance with FASB Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes . Accordingly, the Company reports a liability for unrecognized tax benefits resulting from uncertain tax positions taken or expected to be taken in a tax return. The Company recognizes interest and penalties, if any, related to unrecognized tax benefits in income tax expense.

Minority Interest. As of December 31, 2007, minority interest in the Company s consolidated subsidiaries consisted of the following:

26.19% interest in Sagebrush Pipeline, LLC; and

1.29% interest in Cholla Pipeline, LP.

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 market indexes. The fair value of the fixed portion of the Company s senior credit facility and convertible preferred stock approximate book value as reflected in the accompanying balance sheets.

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 derivatives contracts.

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Continued)

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 2007, 2006 and 2005.

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 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 to be measured at fair value. SFAS No. 157 clarifies guidance in FASB Concepts Statement 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 will implement SFAS No. 157 on January 1, 2008. The Company continues to evaluate the impact of SFAS No. 157 on the consolidated financials 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 , which permits an entity to choose to measure certain financial assets and liabilities at fair value. SFAS No. 159 also revises provisions of SFAS No. 115 that apply to available-for-sale and trading securities. This statement is effective for fiscal years beginning after November 15, 2007. We do not believe the adoption of SFAS No. 159 will have a material impact on our consolidated financial position, results of operations, or cash flows.

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations , which replaces SFAS No. 141. SFAS No. 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any noncontrolling interest in the acquiree and the goodwill acquired. The Statement also establishes disclosure requirements which will enable users to evaluate the nature and financial effects of the business combination. SFAS No. 141(R) is effective for fiscal years beginning after December 15, 2008. The Company plans to implement this standard on January 1, 2009. The Company has not yet evaluated the potential impact of this standard.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment of Accounting Research Bulletin No. 51 , which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent s ownership interest and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. The Statement also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS No. 160 is effective for fiscal years beginning after December 15, 2008. The Company plans to implement this standard on January 1, 2009. The Company has not evaluated the potential impact of this standard.

2. Acquisitions and Dispositions

2005 Acquisitions

The Company closed the following acquisitions in 2005:

Acquired additional equity interests in PetroSource Energy Company, LLC (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;

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SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Continued)

Acquired from an executive officer and director the remaining 50% equity interest in the Company s compression services subsidiary, Lariat Compression Company (Larco), resulting in it becoming a wholly-owned subsidiary;

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

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

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

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

Acquired 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).

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
Larco remaining interest	5,054			(2,446)	500	7,500	
West Texas additional lease interests	10,000				667	10,000	
Piceance Basin additional interests	17,565				1,164	17,456	109
Various additional lease interests	268				17	268	
	689			(2,378)	204	3,067	

Sagebrush additional interests							
Gungoll lease interests	8,074				176	2,622	5,452
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.

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 equity acquisition.

2006 Acquisitions and Dispositions

The Company closed the following acquisitions in 2006:

On March 15, 2006, the Company acquired from an executive officer and director, an additional 12.5% interest in PetroSource. 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 Company common stock (valued at $4.7 million). The cash and equity consideration was paid in July 2006.

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SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Continued)

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

On June 7, 2006, the Company acquired the remaining 1% interest in PetroSource Energy Company, a consolidated subsidiary, from an oil and gas company. The purchase price was 27,749 shares of Company common stock (valued at $0.5 million). As a result of this acquisition, the Company became the 100% owner of PetroSource.

The 2006 acquisitions described above 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):

Acquisition Transaction	Addition to Property, Plant &Equipment	Change in Minority Interest	Retirement of Subordinated Debt(1)	Consideration Paid: Common Stock No. of Shares	Consideration Paid: Common Stock	Consideration Paid: Cash
PetroSource additional interests	$ 2,116	$ (2,370)	$ (1,003)		$	$ 5,489
Purchased leases	40,960					40,960
Oil and natural gas properties	12,850			251	4,650	8,200
Producing well interest from executive officer and director	9,000					9,000
PetroSource additional interest (remaining 1% interest)	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 resulting in a gain of $12.3 million. The sale was accounted for as an adjustment to the full cost pool, with no gain recognized.

On November 21, 2006, the Company acquired all of the outstanding membership interests in NEG Oil & Gas, or NEG, for approximately $990.4 million in cash, the assumption of $300.0 million in debt, the receipt of cash of $21.1 million, and the issuance of 12,842,000 shares of the Company s common stock (valued at approximately $231.2 million). 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. 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 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.

In the fourth quarter of 2007, we completed our valuation of assets acquired and liabilities assumed related to the NEG acquisition and allocated the appropriate fair values. Upon further refinement of the appraisal values, we have increased our values assigned to the properties acquired and reduced the value assigned to goodwill of $26.2 million. The accompanying balance sheet at December 31, 2006 includes the preliminary 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.

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Notes to Consolidated Financial Statements (Continued)

The following table presents the final 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 at the acquisition date and including subsequent adjustments to the purchase price allocation (in thousands):

Cash and cash equivalents	$ 21,100
Accounts receivable	30,840
Other current assets	6,025
Property, plant and equipment	1,524,072
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

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, 2006 and 2005 and the respective unaudited pro forma information to reflect the NEG acquisition (in thousands, except per share amounts):

	Year Ended December 31,			
	2006		2005	
	Actual	Pro Forma	Actual	Pro Forma
	(Unaudited)			
Revenues	$ 388,242	$ 565,256	$ 287,693	$ 560,235

Income (loss) from continuing operations		15,621		36,337		17,893		(49,594)
Net income (loss)		15,621		36,337		18,122		(49,594)
Basic and diluted earnings per share available (applicable) to common stockholders:								
Income (loss) from continuing operations	$	0.21	$	0.40	$	0.31	$	(0.96)
Net income (loss) available to common stockholders	$	0.16	$	0.04	$	0.32	$	(0.96)

2007 Acquisitions

The Company closed the following acquisitions in 2007:

On October 9, 2007, the Company purchased developed and undeveloped properties located in West Texas from an oil and gas company. The purchase price was approximately $73.8 million, comprised of $25.0 million in cash and a $48.8 million note payable. The $25 million cash consideration paid was funded through a draw on the Company s senior credit facility. All principal and accrued interest (interest at 7% annually) due on the note payable were repaid on November 9, 2007 with proceeds from the Company s initial public offering. For additional discussion of the Company s initial public offering, refer to Note 18 herein.

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SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Continued)

On November 28, 2007, the Company purchased a gas treatment plant and related gathering system located in Pecos County, Texas. The purchase price of approximately $10.0 million was paid in cash.

On November 29, 2007, the Company purchased leasehold acreage and producing well interests located predominantly in the WTO from a group of entities controlled by a significant shareholder. The purchase price of approximately $32.0 million was paid in cash.

3. Discontinued Operations

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

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

	2007	2006	2005
Revenues	$	$	$ 1,683
Operating expenses			(1,336)
Income from discontinued operations			347
Income tax expense			(118)
Net income from discontinued operations	$	$	$ 229

No assets were classified as held for sale at December 31, 2007 or 2006.

4. Accounts Receivable

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

	December 31, 2007	December 31, 2006
Oil and natural gas services	$ 6,622	$ 8,489
Oil and natural gas sales	72,393	57,458

Joint interest billing	17,874	26,553
Other	90	299
	96,979	92,799
Less allowance for doubtful accounts	(2,238)	(3,025)
Total accounts receivable, net	$ 94,741	$ 89,774

The following tables show the balance in the allowance for doubtful accounts and activity for the years ended December 31 (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, 2005	$ 1,074	$ 33	$ (256)	$ 851
Year ended December 31, 2006	$ 851	$ 2,528	$ (354)	$ 3,025
Year ended December 31, 2007	$ 3,025	$	$ (787)	$ 2,238

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

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Continued)

5. Other Current Assets

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

	December 31, 2007	December 31, 2006
Prepaid insurance	$ 9,379	$ 7,604
Prepaid drilling	5,924	2,207
Materials and supplies	4,751	6,244
Post closing receivable NEG acquisition		15,232
Other	733	207
Total other current assets	$ 20,787	$ 31,494

6. Property, Plant and Equipment

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

	December 31, 2007	December 31, 2006
Oil and natural gas properties:		
Proved	$ 2,848,531	$ 1,636,832
Unproved	259,610	282,374
Total oil and natural gas properties	3,108,141	1,919,206
Less accumulated depreciation and depletion	(230,974)	(60,752)
Net oil and natural gas properties capitalized costs	2,877,167	1,858,454
Land	1,149	738
Non oil and gas equipment	539,893	337,294
Buildings and structures	38,288	6,564
Total	579,330	344,596
Less accumulated depreciation, depletion and amortization	(119,087)	(68,332)
Net capitalized costs	460,243	276,264

Total property, plant and equipment	$ 3,337,410	$ 2,134,718

The amount of capitalized interest included in the above non oil and gas equipment balance at December 31, 2007 and 2006 was approximately $3.4 million and $1.4 million, respectively. The Company did not capitalize any interest in 2005.

On July 11, 2007, the Company purchased property to serve as its future corporate headquarters. The 3.51-acre site contains four buildings and is located in downtown Oklahoma City, Oklahoma. The purchase price was approximately $29.5 million in cash. Payment of the purchase price was funded through a draw on the Company s senior credit facility.

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Continued)

Costs Excluded from Amortization

Costs associated with unproved properties related to continuing operations of $259.6 million as of December 31, 2007 are excluded from amounts subject to amortization. A summary of costs related to unproved properties which have been excluded from oil and natural gas properties being amortized at December 31, 2007 and the year in which they were incurred is as follows:

	Year Cost Incurred				Excluded Costs at
	Prior Years	2005	2006	2007	December 31, 2007
Property acquisition	$	$	$ 259,610	$	$ 259,610
Exploration					
Development					
Capitalized interest					
Total costs incurred	$	$	$ 259,610	$	$ 259,610

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 $2.64 per Mcfe in 2007, $1.68 per Mcfe in 2006 and $1.23 per Mcfe in 2005.

7. Investment in Affiliated Companies

The Company has certain investments that it accounts for under the equity method of accounting because it owns more than 20% and has significant influence but does not control. The equity method investments include the following:

Grey Ranch, L.P. Grey Ranch is primarily engaged in process and transportation of gas and natural gas liquids. The Company purchased its investment during 2003. At December 31, 2007 and 2006, the Company owned 50% of Grey Ranch, L.P. and had approximately $4,176,000 and $2,201,000, respectively, recorded in the consolidated balance sheets relating to this investment. The Company contributed a disproportionate amount of capital into the partnership, amounting to approximately $750,000, as of December 31, 2007 and 2006. The excess amount contributed is being amortized over the average life of the partnership s long-lived assets.

Larclay, L.P. The Company and Clayton Williams Energy, Inc. (CWEI) each own a 50% interest in Larclay, L.P., a limited partnership formed to acquire drilling rigs and provide land drilling services. The Company purchased its investment in 2006 and accounts for it under the equity method of accounting. The Company serves as the operations manager of the partnership. CWEI was responsible for securing the financing and purchasing the rigs. The partnership financed 100% of the acquisition cost of the rigs through a guarantee by CWEI. At December 31, 2007 and 2006, the

Company had approximately $3,780,000 and $1,383,000, respectively, recorded in the consolidated balance sheets relating to this investment.

8. Restricted Deposits

Restricted deposits represent bank trust and escrow accounts required by the U.S. Department of Interior s Minerals Management Service, surety bond underwriters, purchase agreements or other settlement agreements to satisfy the Company s eventual responsibility to plug and abandon wells and remove structures when certain offshore fields are no longer in use. These restricted deposits were acquired as part of the NEG acquisition in November 2006 (See Note 2).

In connection with one of these agreements, the Company is required to make scheduled quarterly deposits of $0.8 million to an escrow account. Aggregate scheduled fundings under this agreement are as follows (in thousands):

Years ending December 31:	
2008	$ 3,200
2009	3,200
2010 and none thereafter	2,586

Additionally, two of the agreements require us to deposit additional funds in an escrow account equal to 10% of the net proceeds, as defined, from certain of our offshore properties. During 2007, we deposited approximately $5.8 million in these escrow accounts.

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Continued)

During 2007, we were released from obligations under two of these escrow agreements. As a result, funds totaling $10.3 million were released from escrow accounts and returned to the Company.

9. Accounts Payable and Accrued Expenses

Accounts payable and accrued expenses consist of the following (in thousands):

	December 31, 2007	December 31, 2006
Accounts payable-trade	$ 154,423	$ 103,683
Redeemable convertible preferred stock dividends	8,956	
Payroll and benefits	15,690	10,718
Drilling advances	5,817	5,318
Legal (current)	5,000	5,000
Accrued interest	24,201	3,850
Other	1,410	1,230
Total accounts payable and accrued expenses	$ 215,497	$ 129,799

10. Long-Term Debt

Long-term obligations consist of the following (in thousands):

	December 31, 2007	December 31, 2006
Senior term loans	$ 1,000,000	$
Senior credit facility		140,000
Senior bridge facility		850,000
Other notes payable:		
Drilling rig fleet and related oil field services equipment	47,836	61,105
Mortgage	19,651	
Sagebrush		4,000
Insurance financing		7,240
Other equipment and vehicles	162	4,486
Total debt	1,067,649	1,066,831
Less: Current maturities of long-term debt	15,350	26,201
Long-term debt	$ 1,052,299	$ 1,040,630

Senior Credit Facility. On November 21, 2006, the Company entered into a $750 million senior secured revolving credit facility (the senior credit facility). The senior credit facility matures on November 21, 2011.

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

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

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Continued)

The senior credit facility also contains financial covenants, including maintenance of agreed upon levels for the (i) ratio of total funded debt to EBITDAX (as defined in the senior credit facility), (ii) ratio of EBITDAX to interest expense plus current maturities of long-term debt, and (iii) current ratio. The Company was in compliance with these financial covenants as of December 31, 2007.

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

At the Company s election, interest under the senior credit facility is determined by reference to (i) the LIBOR rate 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 is 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 is paid at the end of each three-month period. The average interest rate paid on amounts outstanding under our senior credit facility for the year ended December 31, 2007 was 7.34%.

The borrowing base of proved reserves was initially set at $300.0 million. As of December 31, 2006, the Company had $140.0 million of outstanding indebtedness on the senior credit facility. Proceeds from the Company s sale of common stock on March 20, 2007, as described in Note 18, were used to pay outstanding borrowings under the Company s senior credit facility.

The borrowing base was increased to $400.0 million on May 2, 2007, and to $700.0 million on September 14, 2007 where it remained at December 31, 2007. At December 31, 2007, the Company had no amounts outstanding under this facility. The Company repaid all amounts outstanding under this facility in November 2007. See Note 18 for further discussion.

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

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

Senior Bridge Facility. On November 21, 2006, the Company also entered into a $850.0 million senior unsecured bridge facility (the senior bridge facility), which was repaid in March 2007. The Company expensed the remaining unamortized debt issuance costs related to the senior bridge facility of approximately $12.5 million to interest expense in March 2007.

Together with borrowings under the senior credit facility, the proceeds from the senior bridge facility were used to (i) partially finance the NEG acquisition, (ii) refinance existing senior secured revolving credit facility and NEG s existing credit facility, and (iii) pay fees and expenses related to the NEG acquisition and the existing credit facility.

Senior Term Loans. On March 22, 2007, the Company entered into $1.0 billion in senior unsecured term loans (the senior term loans). The closing of the senior term loans was generally contingent upon closing the private placement of common equity as described in Note 18. The senior term loans include both floating rate term loans and fixed rate term loans.

The Company issued $350.0 million at a variable rate with interest payable quarterly and principal due on April 1, 2014 (the variable rate term loans). The variable rate term loans bear interest, at the Company s option, at the British Bankers Association LIBOR rate plus 3.625% or the higher of (i) the federal funds rate, as defined, plus 3.125% or (ii) a bank s prime rate plus 2.625%. After April 1, 2009 the variable rate term loans may be prepaid in whole or in part with certain prepayment penalties. The average interest rates paid on amounts outstanding under the Company s variable term loans for the year ended December 31, 2007 was 8.94%. Subsequent to year end, the Company entered into an interest rate swap to effectively fix the interest rate related to this portion of the term loan through April 1, 2011 (See Note 20).

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Continued)

The Company issued $650.0 million at a fixed rate of 8.625% with the principal due on April 1, 2015 (the fixed rate term loans). Under the terms of the fixed rate term loans, interest is payable quarterly and during the first four years interest may be paid, at the Company s option, either entirely in cash or entirely with additional fixed rate term loans. If the Company elects to pay the interest due during any period in additional fixed rate term loans, the interest rate increases to 9.375% during such period. After April 1, 2011, the fixed rate term loans may be prepaid in whole or in part with certain prepayment penalties.

After March 22, 2008, but not later than April 30, 2008, the Company is required to offer to exchange the senior term loans for senior unsecured notes with registration rights and with identical terms and conditions as the term loans. If the Company does not complete the exchange of the senior term loans for senior unsecured notes with registration rights by May 31, 2008, the annual interest rate on the senior term loans will increase by 0.25% every 90 days up to a maximum of 0.50%.

Debt covenants under the senior term loans include financial covenants similar to those of the senior credit facility and include limitations on the incurrence of indebtedness, payment of dividends, asset sales, certain asset purchases, transactions with related parties, and consolidation or merger agreements. The Company incurred $26.1 million of debt issuance costs in connection with the senior term loans. These costs are included in other assets and amortized over the term of the senior term loans. A portion of the proceeds from the senior term loans was used to repay the Company s $850.0 million senior bridge facility.

Other Indebtedness. The Company has financed a portion of its drilling rig fleet and related oil field services equipment through notes. At December 31, 2007, the aggregate outstanding balance of these notes was $47.8 million, with an annual fixed interest rate ranging from 7.64% to 8.87%. The notes have a final maturity date of December 1, 2011, require aggregate monthly installments for principal and interest in the amount of $1.2 million and are secured by the equipment. The notes have a prepayment penalty (currently 1-3%) in the event the Company repays the notes prior to maturity.

On November 15, 2007, the Company entered into a note payable in the amount of $20 million with a lending institution as a mortgage on the downtown Oklahoma City property purchased by the Company in July 2007 (see additional discussion in Note 6). This note is fully secured by one of the buildings and a parking garage located on the downtown property, bears interest at 6.08% annually, and matures on November 15, 2022. Payments of principal and interest in the amount of approximately $0.5 million are due on a quarterly basis through the maturity date. During 2008, the Company expects to make payments of principal and interest on this note totaling $0.8 million and $1.2 million, respectively.

Prior to 2007, the Company financed the purchase of various vehicles, oil field services equipment and other equipment through various notes payable. The aggregate outstanding balance of these notes as of December 31, 2006 was $4.5 million. Additionally, the Company financed its insurance payment made in 2007. These notes were substantially repaid during 2007 with borrowings under our senior credit facility. Also, in 2007 we repaid a $4.0 million loan incurred in 2005 for the purpose of completing a gas processing plant and pipeline in Colorado.

Prior Senior Credit Facility. On November 21, 2006, we replaced a $130 million revolving credit facility with our existing senior credit facility. The prior senior credit facility bore interest at the Company s option at either LIBOR plus 2.15% or the Bank of America, N.A. prime rate. The Company paid a commitment fee on the unused portion of the borrowing base amount equal to 1/8% per annum. The prior senior credit facility was collateralized by natural gas and oil properties representing at least 80% of the present discounted value of the Company s proved reserves and by a negative pledge on any of the Company s non-mortgaged properties.

Maturities of Long-Term Debt. Aggregate maturities of long-term debt during the next five years are as follows (in thousands):

Years ending December 31:		
2008	$	15,350
2009		16,580
2010		12,476
2011		7,222
2012		1,052
Thereafter		1,014,969
Total debt	$	1,067,649

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SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Continued)

11. Other Long-Term Obligations

The Company has recorded a long-term obligation for amounts to be paid under a litigation settlement agreement with Conoco, Inc. entered into in January 2007. The Company agreed to pay approximately $25.0 million plus interest, payable in $5.0 million increments on April 1, 2007, July 1, 2008, July 1, 2009, July 1, 2010, and July 1, 2011. The $5.0 million payment made in 2007 has been included in accounts payable-trade in the accompanying consolidated balance sheet as of December 31, 2006, and the $5.0 million payment to be made in 2008 has been included in accounts payable-trade in the accompanying consolidated balance sheet as of December 31, 2007. Unpaid settlement amounts of approximately $15.0 million and $20.0 million have been included in other long-term obligations in the accompanying consolidated balance sheets as of December 31, 2007 and 2006, respectively.

12. Derivatives

The Company has entered into various derivative contracts including fixed price swaps, collars and basis swaps with counterparties. The contracts expire on various dates through December 31, 2009.

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

Period	Commodity	Notional	Weighted Avg. Fixed Price	
Fixed price swaps:				
November 2007 March 2008	Natural gas	1,520,000 MmBtu	$	8.51
November 2007 June 2008	Natural gas	4,860,000 MmBtu	$	8.05
November 2007 June 2008	Natural gas	9,720,000 MmBtu	$	8.20
January 2008	Natural gas	310,000 MmBtu	$	8.24
January 2008 June 2008	Natural gas	3,640,000 MmBtu	$	7.99
January 2008 June 2008	Natural gas	3,640,000 MmBtu	$	7.99
January 2008 December 2008	Natural gas	3,660,000 MmBtu	$	8.23
January 2008 December 2008	Natural gas	3,660,000 MmBtu	$	8.48
January 2008 December 2008	Natural gas	3,660,000 MmBtu	$	9.00
April 2008 June 2008	Natural gas	910,000 MmBtu	$	7.17
May 2008 August 2008	Natural gas	2,460,000 MmBtu	$	8.38
July 2008	Natural gas	310,000 MmBtu	$	8.00
July 2008	Natural gas	310,000 MmBtu	$	8.02
July 2008 September 2008	Natural gas	920,000 MmBtu	$	7.43
July 2008 September 2008	Natural gas	920,000 MmBtu	$	7.49
July 2008 September 2008	Natural gas	920,000 MmBtu	$	8.06
July 2008 September 2008	Natural gas	920,000 MmBtu	$	8.07
July 2008 September 2008	Natural gas	920,000 MmBtu	$	8.23
July 2008 September 2008	Natural gas	920,000 MmBtu	$	8.36
July 2008 December 2008	Natural gas	1,840,000 MmBtu	$	8.31

July 2008 December 2008	Natural gas	1,840,000 MmBtu	$	8.59
August 2008	Natural gas	310,000 MmBtu	$	8.00
August 2008	Natural gas	310,000 MmBtu	$	8.07
September 2008	Natural gas	300,000 MmBtu	$	8.05
September 2008	Natural gas	300,000 MmBtu	$	8.10
October 2008 December 2008	Natural gas	920,000 MmBtu	$	7.96

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Period	Commodity	Notional	Weighted Avg. Fixed Price
October 2008 December 2008	Natural gas	1,840,000 MmBtu	$ 8.00
October 2008 December 2008	Natural gas	920,000 MmBtu	$ 8.07
October 2008 December 2008	Natural gas	920,000 MmBtu	$ 8.11
October 2008 December 2008	Natural gas	920,000 MmBtu	$ 8.16
October 2008 December 2008	Natural gas	920,000 MmBtu	$ 8.32
October 2008 December 2008	Natural gas	920,000 MmBtu	$ 8.83
January 2009 March 2009	Natural gas	900,000 MmBtu	$ 8.56
January 2009 March 2009	Natural gas	900,000 MmBtu	$ 8.60
January 2009 March 2009	Natural gas	900,000 MmBtu	$ 8.65
January 2009 March 2009	Natural gas	900,000 MmBtu	$ 8.91
Collars:			
January 2008 June 2008	Crude oil	42,000 Bbls	$ 50.00 - $83.35
July 2008 December 2008	Crude oil	54,000 Bbls	$ 50.00 - $82.60
Waha basis swaps:			
January 2008 December 2008	Natural gas	10,980,000 MmBtu	$ (0.57)
January 2008 December 2008	Natural gas	7,320,000 MmBtu	$ (0.585)
January 2008 December 2008	Natural gas	7,320,000 MmBtu	$ (0.59)
January 2008 December 2008	Natural gas	3,660,000 MmBtu	$ (0.595)
January 2008 December 2008	Natural gas	3,660,000 MmBtu	$ (0.625)
January 2008 December 2008	Natural gas	7,320,000 MmBtu	$ (0.635)
January 2008 December 2008	Natural gas	7,320,000 MmBtu	$ (0.6525)
May 2008 August 2008	Natural gas	2,460,000 MmBtu	$ (0.45)
June 2008 August 2008	Natural gas	920,000 MmBtu	$ (0.4808)
September 2008 December 2008	Natural gas	2,440,000 MmBtu	$ (0.7930)
January 2009 December 2009	Natural gas	3,650,000 MmBtu	$ (0.47)
January 2009 December 2009	Natural gas	3,650,000 MmBtu	$ (0.49)
January 2009 December 2009	Natural gas	3,650,000 MmBtu	$ (0.4975)

These derivatives have not been designated as hedges. The Company records all derivatives on the balance sheet at fair value. Changes in derivative fair values are recognized in earnings. Cash settlements and valuation gains and losses are included in (gain) loss on derivative contracts in the consolidated statements of operations. The following summarizes the cash settlements and valuation gains and losses for the years ended December 31 (in thousands):

	2007	2006	2005
Realized (gain) loss	$ (34,494)	$ (14,169)	$ 2,836
Unrealized (gain) loss	(26,238)	1,878	1,296
(Gain) loss on derivative contracts	$ (60,732)	$ (12,291)	$ 4,132

13. Retirement and Deferred Compensation Plans

Retirement Plan. The Company maintains a 401(k) retirement plan for its employees. Under the plan, eligible employees may elect to defer a portion of their earnings up to the maximum allowed by regulations promulgated by the Internal Revenue Service. Prior to August 2006, the Company made matching contributions equal to 50% on the first 6% of employee deferred wages (maximum 3% matching). The Company modified the 401(k) retirement plan in August 2006 to change the matching contributions to equal a match of 100% on the first 15% of employee deferred wages (maximum 15% matching). The plan was also modified to make the matching contributions payable in Company common stock. Accrued payables in the amounts of $5.2 million and $1.3 million are

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Notes to Consolidated Financial Statements (Continued)

reflected in the consolidated balance sheets as of December 31, 2007 and 2006, respectively, related to the matching contributions. During June 2007, the Company satisfied its matching obligation related to employees contributions made in 2006 through a transfer of treasury stock (See Note 18). For 2007, 2006 and 2005, retirement plan expense was approximately $4.9 million, $1.5 million and $0.3 million, respectively.

Deferred Compensation Plan. Effective February 1, 2007 the Company 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 IRA annual limitations on qualified 401(k) retirement plans. The 2007 annual 401(k) deferral limit for employees under age 50 was $15,500. Employees turning age 50 or over in 2007 could defer up to $20,500.

14. Income Taxes

On January 1, 2007, the Company adopted the provisions of FIN 48. The Company has determined that no uncertain tax positions exist and therefore no reserves have been recorded for purposes of FIN 48 as of December 31, 2007. As a result, the Company has not recorded any additional liabilities for any unrecognized tax benefits as of December 31, 2007. The Company and its subsidiaries file income tax returns in the U.S. federal and various state jurisdictions. Tax years 1994 to present remain open for the majority of taxing authorities. The Company s accounting policy is to recognize interest and penalties, if any, related to unrecognized tax benefits as income tax expense. The Company does not have an accrued liability for the payment of penalties and interest at December 31, 2007.

Significant components of the Company s deferred tax assets (liabilities) are as follows (in thousands):

	December 31,	
	2007	**2006**
Deferred tax assets (liabilities):		
Current:		
Accrued liabilities	$ 1,820	$ 4,451
Other		1,864
Total current deferred tax assets	$ 1,820	$ 6,315
Noncurrent:		
Property, plant and equipment	$ (45,537)	$ (25,692)
Net operating loss carryforwards	2,397	
Other	(6,210)	770
Total noncurrent deferred tax liabilities	$ (49,350)	$ (24,922)

The provisions for income taxes for continuing operations consisted of the following components for the years ended December 31 (in thousands):

	2007	2006	2005
Current:			
Federal	$	$ 3,235	$ 508
State	601	2,653	
	601	5,888	508
Deferred:			
Federal	28,121	345	9,460
State	802	3	
	28,923	348	9,460
Total provision for income taxes	$ 29,524	$ 6,236	$ 9,968

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Notes to Consolidated Financial Statements (Continued)

A reconciliation of the provision for income taxes from continuing operations at the statutory federal tax rates to the Company s actual provision for income taxes is as follows for the years ended December 31 (in thousands):

	2007	2006	2005
Computed at federal statutory rates	$ 27,911	$ 7,650	$ 9,543
State taxes, net of federal benefit	912	1,724	390
Nondeductible expenses	312	84	35
Percentage depletion deduction		(3,488)	
Change in rate		326	
Other	389	(60)	
Total provision for income taxes	$ 29,524	$ 6,236	$ 9,968

As of December 31, 2007, the Company had $6.8 million of net operating loss carryforwards that will begin to expire in 2023. The Company, as of December 31, 2007, had approximately $0.5 million of alternative minimum tax credits that do not expire.

15. Earnings Per Share

Basic earnings per share are computed using the weighted average number of common shares outstanding during the year. Diluted earnings per share are computed using the weighted average shares outstanding during the year, but also include the dilutive effect of awards of restricted stock. The following table summarizes the calculation of weighted average common shares outstanding used in the computation of diluted earnings per share for the years ended December 31 (in thousands).

	2007	2006	2005
Weighted average basic common shares outstanding	108,828	73,727	56,559
Effect of dilutive securities:			
Restricted stock	1,213	937	178
Weighted average diluted common and potential common shares outstanding	110,041	74,664	56,737

In computing diluted earnings per share, the Company evaluated the if-converted method with respect to its outstanding redeemable convertible preferred stock. Under this method, the Company assumes the conversion of the preferred stock to common stock and determines if this is more dilutive than including the preferred stock dividends (paid and unpaid) in the computation of income available to common stockholders. The Company determined the if-converted method is not more dilutive and has included preferred stock dividends in the determination of income available to common stockholders.

16. Commitments and Contingencies

Operating Leases. The Company has obligations under noncancelable operating leases, primarily for the use of office space and equipment. Total rental expense under operating leases for the years ended December 31, 2007, 2006 and 2005 was approximately $2.3 million, $1.1 million and $1.1 million, respectively.

Future minimum lease payments under noncancelable operating leases (with initial lease terms in excess of one year) as of December 31, 2007 are as follows (in thousands):

Years ending December 31:	
2008	$ 2,139
2009	1,102
2010	110
2011	110
2012	45
Thereafter	
	$ 3,506

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Notes to Consolidated Financial Statements (Continued)

Litigation. The Company is a defendant in lawsuits from time to time in the normal course of business. In management s opinion, the Company is not currently involved in any legal proceedings which, individually or in the aggregate, could have a material effect on the financial condition, operations and/or cash flows of the Company.

17. Redeemable Convertible Preferred Stock

In November 2006, the Company sold 2,136,667 shares of redeemable convertible preferred stock in order to finance a portion of the NEG acquisition and received net proceeds from this sale of approximately $439.5 million after deducting offering expenses of approximately $9.3 million (See Note 2). Each holder of the redeemable convertible preferred stock is entitled to quarterly cash dividends at the annual rate of 7.75% of the accreted value of its redeemable convertible preferred stock. The accreted value was $210 per share as of December 31, 2007 and 2006. Each share of convertible preferred stock was initially convertible into ten (10.2 currently) shares of common stock at the option of the holder, subject to certain anti-dilution adjustments. A summary of dividends declared and paid on the redeemable convertible preferred stock is as follows (in thousands, except per share data):

Declared	Dividend Period	Dividends per Share	Total	Date Paid
January 31, 2007	November 21, 2006 February 1, 2007	$ 3.21	$ 6,859	February 15, 2007
May 8, 2007	February 2, 2008 May 1, 2007	3.97	8,550	May 15, 2007
June 8, 2007	May 2, 2007 August 1, 2007	4.10	8,956	August 15, 2007
September 24, 2007	August 2, 2007 November 1, 2007	4.10	8,956	November 15, 2007
December 16, 2007	November 2, 2007 February 1, 2008	4.10	8,956	February 15, 2008

On March 30, 2007, certain holders of the Company s common units (consisting of shares of common stock and a warrant to purchase redeemable convertible preferred stock upon the surrender of common stock) exercised warrants to purchase redeemable convertible preferred stock. The holders exchanged 526,316 shares of common stock for 47,619 shares of redeemable convertible preferred stock.

Approximately $38.5 million and $3.8 million in paid and unpaid dividends have been included in the Company s earnings per share calculations for the years ended December 31, 2007 and 2006, respectively, as presented in the accompanying consolidated statements of operations.

18. Stockholders Equity

The following table presents information regarding SandRidge s common stock (in thousands):

	December 31, 2007	December 31, 2006

Shares authorized	400,000	400,000
Shares outstanding at end of period	140,391	91,604
Shares held in treasury	1,456	1,444

The Company is authorized to issue 50,000,000 shares of preferred stock, $0.001 par value, of which 2,625,000 shares are designated as redeemable convertible preferred. As of December 31, 2007 and 2006 there were 2,184,286 and 2,136,667 shares, respectively, of redeemable convertible preferred stock outstanding (See Note 17). There were no undesignated preferred shares outstanding as of December 31, 2007 and 2006.

Stock Split. On December 19, 2005, the Company effected a 281.562 for 1 stock split. All references in the accompanying financial statements have been restated to reflect this stock split. The Company also authorized 400,000,000 shares of common stock with a par value of $0.001 per share.

Common Stock Issuance. In December 2005, the Company sold 12.5 million shares of common stock in a private placement and received net proceeds from this sale of approximately $173.1 million after deducting the initial purchasers discount of $16.8 million and offering expenses of approximately $1.2 million. Approximately $105.5 million of the proceeds of the offering were used to repay outstanding bank debt and finance the Company s December 2005 acquisitions (See Note 2).

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Notes to Consolidated Financial Statements (Continued)

In January 2006, the Company issued an additional 239,630 shares of common stock upon exercise of an over-allotment option. The Company issued these shares at a price of $15.00 per share after deducting the purchasers fee of $0.3 million. The Company received net proceeds from the sale of approximately $3.3 million.

In November 2006, the Company sold 5.3 million common units (consisting of shares of common stock ($18.00 per share) and a warrant ($1.00 per share) to purchase convertible preferred stock upon the surrender of the common stock) as part of the NEG acquisition and received net proceeds from this sale of approximately $97.4 million after deducting the offering expenses of approximately $3.9 million (See Note 2).

In March 2007, the Company sold approximately 17.8 million shares of common stock for net proceeds of $318.7 million after deducting offering expenses of approximately $1.4 million. The stock was sold in private sales to various investors including Tom L. Ward, the Company s Chairman of the Board of Directors and Chief Executive Officer, who invested $61.4 million in exchange for approximately 3.4 million shares of common stock.

On November 9, 2007, the Company completed an initial public offering (the IPO) of its common stock. The Company sold 28,700,000 shares of SandRidge common stock, including 4,710,000 shares sold directly to an entity controlled by Tom L. Ward. The shares were sold at a price of $26 per share. After deducting underwriting discounts of approximately $38.3 million and estimated offering expenses of approximately $3.1 million, the Company received net proceeds of approximately $704.8 million. This transaction priced after market close on November 5, 2007. In conjunction with the IPO, the underwriters were granted an option to purchase 3,679,500 additional shares of the Company s common stock. The underwriters fully exercised this option and purchased the additional shares on November 6, 2007. After deducting underwriting discounts of approximately $5.7 million, the Company received net proceeds of approximately $89.9 million from these additional shares. This offering generated total gross proceeds to the Company of $841.8 million and total net proceeds of approximately $794.7 million to the Company after deducting total underwriting discounts of approximately $44.0 million and other offering expenses of approximately $3.1 million. The aggregate net proceeds of approximately $794.7 million received by the Company at closing on November 9, 2007 were utilized as follows (in millions):

Repayment of outstanding balance and accrued interest on senior credit facility	$ 515.9
Repayment of note payable and accrued interest incurred in connection with recent acquisition	49.1
Excess cash to fund future capital expenditures	229.7
Total	$ 794.7

Treasury Stock. The Company makes required tax payments on behalf of employees as their stock awards vest and then withholds a number of vested shares having a value on the date of vesting equal to the tax obligation. As a result of such transactions, the Company withheld 44,649 shares at a total value of $0.8 million and 29,000 shares at a total value of $0.5 million during the years ended December 31, 2007 and 2006, respectively. These shares were accounted for as treasury stock.

On June 28, 2007, the Company purchased 39,844 shares of its common stock into treasury through an open market repurchase transaction in order to fund a portion of its 401(k) matching obligation as described below. Cash consideration for these shares of approximately $0.8 million was paid in July 2007.

On June 29, 2007, the Company transferred 72,044 shares of its treasury stock to an account established for the benefit of the Company s 401(k) Plan. The transfer was made in order to satisfy the Company s $1.3 million accrued payable to match employee contributions made to the plan during 2006. Historical cost of the shares transferred totaled approximately $0.9 million, resulting in an increase to the Company s additional paid-in capital of approximately $0.4 million.

Restricted Stock. The Company issues restricted stock awards under incentive compensation plans which vest over specified periods of time. Awards issued prior to 2006 had vesting periods of one, four or seven years. All awards issued during and after 2006 have four year vesting periods. Shares of restricted common stock are subject to restriction on transfer and certain conditions to vesting.

The Company granted restricted stock awards of approximately 1.6 million shares in December 2005. The stock awards included (i) 153,667 shares scheduled to vest on December 31, 2006, (ii) 904,833 shares scheduled to vest on June 30, 2010, and (iii) 493,667 shares scheduled to vest on June 30, 2013. In June 2006, the Company modified the vesting periods of the one year period and four year period restricted stock awards. One year restricted stock awards were modified to vest on October 1, 2006, rather than December 31, 2006, and four year restricted stock awards were modified to vest 25% each January 1, for four years, beginning

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Notes to Consolidated Financial Statements (Continued)

January 1, 2007, rather than all vesting on June 30, 2010. The Company recognized compensation cost related to these modifications of $17,250 in June 2006.

Additionally, the Company modified the vesting period related to restricted shares awarded to certain executive officers who resigned in June 2006 and August 2006 as a component of their separations from the Company. The Board of Directors agreed to immediately vest all of the executive officers restricted stock, a total of 222,000 shares, including 20,334 shares which would have vested in 2006, 150,000 shares which would have vested in 2010, and 51,666 shares which would have vested in 2013. The Company recognized compensation cost related to these modifications of $2.3 million in the year ended December 31, 2006.

In December 2006, the Company accelerated the vesting of 39,960 restricted shares on behalf of certain employees who resigned from the Company in late December 2006. These shares had been scheduled to vest on January 1, 2007. The Company recognized additional compensation cost in December 2006 for these shares of approximately $0.1 million due to the modification. Other restricted shares held by these employees were forfeited.

Restricted stock activity for the year ended December 31, 2007 was as follows (shares in thousands):

	Number of Shares	Weighted-Average Grant Date Fair Value
Unvested restricted shares outstanding at December 31, 2006	937	$ 15.88
Granted	1,600	19.79
Vested	(466)	15.62
Canceled	(144)	15.15
Unvested restricted shares outstanding at December 31, 2007	1,927	$ 19.25

For the year ended December 31, the Company recognized stock-based compensation expense related to restricted stock of approximately $7.2 million in 2007, $8.8 million in 2006, and $0.5 million in 2005. Stock-based compensation expense is reflected in general and administrative expense in the consolidated statements of operations.

As of December 31, 2007, there was approximately $30.5 million of unrecognized compensation cost related to unvested restricted stock awards which is expected to be recognized over a weighted average period of 2.21 years.

19. Related Party Transactions

During the ordinary course of business, the Company has transactions with certain shareholders and other related parties. These transactions primarily consist of purchases of drilling equipment and sales of oil field service supplies. Following is a summary of significant transactions with such related parties for the years ended December 31 (in thousands):

	2007	2006	2005
Sales to and reimbursements from related parties	$ 118,631	$ 14,102	$ 12,673
Purchases of services from related parties	$ 77,555	$ 4,811	$ 37

In August 2006, the Company sold various non-energy related assets to the Company s former President and Chief Operating Officer, N. Malone Mitchell, 3rd, for approximately $6.1 million in cash. The sale transaction resulted in a $0.8 million gain recognized in earnings by the Company in August 2006. The gain is included in gain on sale of assets in the consolidated statements of operations.

In September 2006, the Company entered into a facilities lease with a member of its Board of Directors. The Company believes that the payments to be made under this lease are at fair market rates. Rent expense related to the lease totaled $1.3 million and $0.3 million for the years ended December 31, 2007 and 2006, respectively. The lease extends to August 2009.

In May 2007, the Company purchased leasehold acreage from a partnership controlled by a director. The purchase price was approximately $8.3 million in cash.

In June 2007, the Company purchased certain producing well interests from a director. The purchase price was approximately $3.5 million in cash.

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Larclay, L.P. The Company and CWEI each own a 50% interest in Larclay, L.P., a limited partnership formed to acquire drilling rigs and provide land drilling services. Larclay currently owns 12 rigs, one of which has not yet been assembled. The Company purchased its investment in 2006 and accounts for it under the equity method of accounting. The Company serves as the operations manager of the partnership. CWEI is responsible for financing and purchasing the rigs. The Company had sales to and cost reimbursements from Larclay for the years ended December 31, 2007 and 2006 of $53.3 million and $1.6 million, respectively. As of December 31, 2007 and 2006, the Company had accounts receivable related party due from Larclay of $16.6 million and $3.0 million, respectively. Additionally, the Company contracted with Larclay to utilize rigs for drilling. For the year ended December 31, 2007 the amount we were billed for these services was $33.3 million. As of December 31, 2007, the Company had accounts payable related party due to Larclay of $0.3 million. The Company made no purchases from Larclay in 2006.

See Note 2 for a discussion of additional related party transactions.

20. Subsequent Events

In January 2008, the Company entered into an interest rate swap to fix the variable LIBOR interest rate on the $350.0 million floating rate portion of its term loan at 6.26% for the period from April 1, 2008 to April 1, 2011. This swap has not been designated as a hedge.

21. Industry Segment Information

SandRidge has four business segments: Exploration and Production, Drilling and Oil Field Services, Midstream Services, and Other representing its four main business units offering different products and services. The Exploration and Production segment is engaged in the development, acquisition and production of oil and natural gas properties. The Drilling and Oil Field Services segment is engaged in the land contract drilling of oil and natural gas wells. The Midstream Gas Services segment is engaged in the purchasing, gathering, processing and treating of natural gas. The Other segment transports CO_2 to market for use by the Company and others in tertiary oil recovery operations and other miscellaneous operations.

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The accounting policies of the segments are the same as those described in the Summary of Significant Accounting Policies (Note 1). Management evaluates the performance of SandRidge s operating segments based on operating income, which is defined as operating revenues less operating expenses and depreciation, depletion and amortization. Summarized financial information concerning the Company s segments is shown in the following table (in thousands):

	2007	2006	2005
Revenues:			
Exploration and production	$ 479,321	$ 106,990	$ 54,425
Elimination of inter-segment revenue	574	577	374
Exploration and production, net of inter-segment revenue	478,747	106,413	54,051
Drilling and oil field services	261,818	211,055	109,766
Elimination of inter-segment revenue	188,616	72,398	29,615
Drilling and oil field services, net of inter-segment revenue	73,202	138,657	80,151
Midstream services	285,065	192,960	192,503
Elimination of inter-segment revenue	177,487	70,068	45,004
Midstream services, net of inter-segment revenues	107,578	122,892	147,499
Other	29,286	21,411	6,164
Elimination of inter-segment revenue	11,361	1,131	172
Other, net of inter-segment revenue	17,925	20,280	5,992
Total revenues	$ 677,452	$ 388,242	$ 287,693
Operating Income:			
Exploration and production	$ 198,913	$ 17,069	$ 14,886
Drilling and oil field services	10,473	32,946	18,295
Midstream services	6,783	3,528	4,096
Other	(29,310)	(16,562)	(3,224)
Total operating income	186,859	36,981	34,053
Interest expense, net	(111,762)	(15,795)	(5,071)
Other income (expense), net	4,648	671	(1,121)
Income before income taxes	$ 79,745	$ 21,857	$ 27,861
Identifiable Assets(1):			

Exploration and production	$ 3,143,137	$ 2,091,459	$ 243,612
Drilling and oil field services	271,563	175,169	100,995
Midstream services	127,822	75,606	33,845
Other	88,044	46,150	80,231
Total assets	$ 3,630,566	$ 2,388,384	$ 458,683
Capital Expenditures:			
Exploration and production	$ 1,046,552	$ 170,872	$ 61,227
Drilling and oil field services	123,232	89,810	43,730
Midstream services	63,828	16,975	25,904
Other	47,236	28,884	3,735
Total capital expenditures	$ 1,280,848	$ 306,541	$ 134,596
Depreciation, Depletion and Amortization			
Exploration and production	$ 175,565	$ 28,104	$ 8,796
Drilling and oil field services	37,792	20,268	11,851
Midstream services	6,641	3,180	1,652
Other	7,110	4,074	1,907
Total depreciation, depletion and amortization	$ 227,108	$ 55,626	$ 24,206

(1) Identifiable assets are those used in SandRidge s operations in each industry segment.

Major Customer. During 2007, the Company had sales in excess of 10% of total revenues to an oil and gas purchaser ($76.1 million or 11.2% of total revenues). There were no customers that accounted for 10% or more of our total revenues in 2006 or 2005.

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22. Supplemental Information on Oil and Gas Producing Activities (Unaudited)

The Supplementary Information on Oil and Gas Producing Activities is presented as required by SFAS No. 69, Disclosures about Oil and Gas Producing Activities. The supplemental information includes capitalized costs related to oil and gas producing activities; costs incurred for the acquisition of oil and gas producing activities, exploration and development activities; and the results of operations from oil and gas producing activities. Supplemental information is also provided for per unit production costs; oil and gas production and average sales prices; the estimated quantities of proved oil and gas reserves; the standardized measure of discounted future net cash flows associated with proved oil and gas reserves; and a summary of the changes in the standardized measure of discounted future net cash flows associated with proved oil and gas reserves.

The Company s capitalized costs consisted of the following (in thousands):

Capitalized Costs Related to Oil and Gas Producing Activities

	December 31,		
	2007	**2006**	**2005**
Oil and natural gas properties:			
Proved	$ 2,848,531	$ 1,636,832	$ 160,789
Unproved	259,610	282,374	33,974
Total oil and natural gas properties	3,108,141	1,919,206	194,763
Less accumulated depreciation and depletion	(230,974)	(60,752)	(35,029)
Net oil and natural gas properties capitalized costs	$ 2,877,167	$ 1,858,454	$ 159,734

Costs Incurred in Property Acquisition, Exploration and Development Activities

	2007	**2006**	**2005**
Acquisitions of properties			
Proved	$ 303,282	$ 1,311,029	$ 14,554
Unproved		268,839	21,085
Exploration(1)	361,973	18,612	2,527
Development	485,348	115,153	60,364
Total cost incurred	$ 1,150,603	$ 1,713,633	$ 98,530

(1) 2007 amount includes seismic costs of $38.6 million.

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The Company s results of operations from oil and gas producing activities for each of the years 2007, 2006 and 2005 are shown in the following table (in thousands):

Results of Operations for Oil and Gas Producing Activities

For the Year Ended December 31, 2005	
Revenues	$ 48,405
Expenses:	
Production costs	19,353
Depreciation, depletion and amortization expenses	8,995
Total expenses	28,348
Income before income taxes	20,057
Provision for income taxes	7,020
Results of operations for oil and gas producing activities	$ 13,037
For the Year Ended December 31, 2006	
Revenues	$ 101,252
Expenses:	
Production costs	39,803
Depreciation, depletion and amortization expenses	25,723
Total expenses	65,526
Income before income taxes	35,726
Provision for income taxes	10,718
Results of operations for oil and gas producing activities	$ 25,008
For the Year Ended December 31, 2007	
Revenues	$ 477,612
Expenses:	
Production costs	125,749
Depreciation, depletion and amortization expenses	169,392
Total expenses	295,141
Income before income taxes	182,471
Provision for income taxes	65,690

Results of operations for oil and gas producing activities	$ 116,781

The table below represents the Company s estimate of proved crude oil and natural gas reserves attributable to the Company s net interest in oil and gas properties based upon the evaluation by the Company and its independent petroleum engineers of pertinent geological and engineering data in accordance with United States Securities and Exchange Commission regulations. Estimates of substantially all of the Company s proved reserves have been prepared by the team of independent reservoir engineers and geoscience professionals and are reviewed by members of the Company s senior management with professional training in petroleum engineering to ensure that the Company consistently applies rigorous professional standards and the reserve definitions prescribed by the United States Securities and Exchange Commission.

Netherland, Sewell & Associates, Inc. and DeGolyer and MacNaughton, independent oil and gas consultants, have prepared the estimates of proved reserves of natural gas and crude oil attributable to several portions of the Company s net interest in oil and gas properties as of the end of one or more of 2007, 2006 and 2005. Netherland, Sewell & Associates, Inc. and DeGolyer and MacNaughton are independent petroleum engineers, geologists, geophysicists and petrophysicists and do not own an interest in us or our properties and are not employed on a contingent basis. Netherland, Sewell & Associates, Inc. prepared the estimates of proved

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reserves for all of our properties other than those held by PetroSource, which constitute approximately 89% of our total proved reserves as of December 31, 2007. DeGolyer and MacNaughton prepared the estimates of proved reserves for PetroSource, which constitute approximately 8% of our total proved reserves as of December 31, 2007. The small remaining portion of estimates of proved reserves were based on Company estimates.

The Company believes the geologic and engineering data examined provides reasonable assurance that the proved reserves are recoverable in future years from known reservoirs under existing economic and operating conditions. Estimates of proved reserves are subject to change, either positively or negatively, as additional information is available and contractual and economic conditions change.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, that is, prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. Proved developed reserves are the quantities of crude oil, natural gas liquids and natural gas expected to be recovered through existing investments in wells and field infrastructure under current operating conditions. Proved undeveloped reserves require additional investments in wells and related infrastructure in order to recover the production.

During 2007, the Company recognized additional reserves attributable to extensions and discoveries as a result of successful drilling in the Piñon Field. Drilling expenditures of $97.1 resulted in the addition of 44.7 Bcfe of net proved developed reserves by extending the field boundaries as well as proving the producing capabilities of formations not previously captured as proved reserves. The remaining 55.1 Bcfe of net proved reserves for 2007 are proved undeveloped reserves associated with direct offsets to the 2007 drilling program extending the boundaries of the Piñon Field and zone identification. Changes in reserves associated with the development drilling have been accounted for in revisions of previous reserve estimates.

During 2006, the Company recognized additional reserves attributable to extensions and discoveries as a result of successful drilling in the Piñon Field. Drilling expenditures of $18.6 million resulted in the addition of 10.9 Bcfe of net proved developed reserves by extending the field boundaries as well as proving the producing capabilities of formations not previously captured as proved reserves. The remaining 83.1 Bcfe of net proved reserves for 2006 are proved undeveloped reserves associated with direct offsets to the 2006 drilling program extending the boundaries of the Piñon Field and zone identification. Changes in reserves associated with the development drilling have been accounted for in revisions of previous reserve estimates.

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SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Continued)

Reserve Quantity Information

	Crude Oil (MBbls)	Nat. Gas (MMcf)(a)
Proved developed and undeveloped reserves:		
As of December 31, 2004	682	144,452
Revisions of previous estimates	108	11,679
Acquisitions of new reserves	9,518	32,022
Extensions and discoveries	200	56,133
Production	(72)	(6,873)
As of December 31, 2005	10,436	237,413
Revisions of previous estimates	1,250	19,139
Acquisitions of new reserves	13,753	514,170
Extensions and discoveries	58	93,396
Production	(322)	(13,410)
As of December 31, 2006	25,175	850,708
Revisions of previous estimates	5,492	318,639
Acquisitions of new reserves	53	75,139
Extensions and discoveries	7,849	104,501
Production	(2,042)	(51,958)
As of December 31, 2007	36,527	1,297,029
Proved developed reserves:		
As of December 31, 2004	231	50,981
As of December 31, 2005	899	69,377
As of December 31, 2006	10,994	308,296
As of December 31, 2007	12,532	590,358

(a) Natural gas reserves are computed at 14.65 pounds per square inch absolute and 60 degrees Fahrenheit.

The standardized measure of discounted cash flows and summary of the changes in the standardized measure computation from year to year are prepared in accordance with SFAS No. 69. The assumptions that underlie the computation of the standardized measure of discounted cash flows may be summarized as follows:

the standardized measure includes the Company s estimate of proved crude oil, natural gas liquids and natural gas reserves and projected future production volumes based upon year-end economic conditions;

pricing is applied based upon year-end market prices adjusted for fixed or determinable contracts that are in existence at year-end. The calculated weighted average per unit prices for the Company s proved reserves and future net revenues were as follows:

	At December 31,		
	2007	**2006**	**2005**
Natural gas (per Mcf)	$ 6.46	$ 5.32	$ 8.40
Crude oil (per barrel)	$ 87.47	$ 54.62	$ 54.02

future development and production costs are determined based upon actual cost at year-end;

the standardized measure includes projections of future abandonment costs based upon actual costs at year-end; and

a discount factor of 10% per year is applied annually to the future net cash flows.

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SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Continued)

Standardized Measure of Discounted Future Net Cash Flows Related to Proved Oil and Gas Reserves

		(In thousands)
As of December 31, 2005		
Future cash inflows from production	$	2,558,668
Future production costs		(653,748)
Future development costs(a)		(296,489)
Future income tax expenses		(546,867)
Undiscounted future net cash flows		1,061,564
10% annual discount		(562,410)
Standardized measure of discounted future net cash flows	$	499,154
As of December 31, 2006		
Future cash inflows from production	$	5,901,660
Future production costs		(1,623,216)
Future development costs(a)		(931,947)
Future income tax expenses		(638,599)
Undiscounted future net cash flows		2,707,898
10% annual discount		(1,267,752)
Standardized measure of discounted future net cash flows	$	1,440,146
As of December 31, 2007		
Future cash inflows from production	$	11,578,381
Future production costs		(2,706,208)
Future development costs(a)		(1,640,500)
Future income tax expenses		(1,782,909)
Undiscounted future net cash flows		5,448,764
10% annual discount		(2,730,227)
Standardized measure of discounted future net cash flows	$	2,718,537

(a) Includes abandonment costs.

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SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Continued)

The following table represents the Company s estimate of changes in the standardized measure of discounted future net cash flows from proved reserves (in thousands):

Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Oil and Gas Reserves

Present value as of December 31, 2004	$ 198,962
Changes during the year:	
Revenues less production and other costs	(29,052)
Net changes in prices, production and other costs	225,227
Development costs incurred	56,368
Net changes in future development costs	(86,828)
Extensions and discoveries	96,514
Revisions of previous quantity estimates	47,501
Accretion of discount	28,981
Net change in income taxes	(155,250)
Purchases of reserves in-place	196,206
Timing differences and other(a)	(79,475)
Net change for the year	300,192
Present value as of December 31, 2005	$ 499,154
Revenues less production and other costs	(61,449)
Net changes in prices, production and other costs	(294,437)
Development costs incurred	75,323
Net changes in future development costs	(75,466)
Extensions and discoveries	126,061
Revisions of previous quantity estimates	54,313
Accretion of discount	73,643
Net change in income taxes	(36,962)
Purchases of reserves in-place	1,135,062
Timing differences and other(a)	(55,096)
Net change for the year	940,992
Present value as of December 31, 2006	$ 1,440,146
Changes during the year:	
Revenues less production and other costs	(351,863)
Net changes in prices, production and other costs	800,630
Development costs incurred	485,348
Net changes in future development costs	(723,943)
Extensions and discoveries	328,094

Revisions of previous quantity estimates	998,729
Accretion of discount	88,596
Net change in income taxes	(537,835)
Purchases of reserves in-place	155,051
Timing differences and other(a)	35,584
Net change for the year	1,278,391
Present value as of December 31, 2007	$ 2,718,537

(a) The change in timing differences and other are related to revisions in the Company s estimated time of production and development.

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Continued)

23. Quarterly Financial Results (Unaudited)

Our operating results for each quarter of 2007 and 2006 are summarized below (in thousands, except per share data).

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2007:				
Total revenues	$ 149,064	$ 159,063	$ 153,648	$ 215,677
Income from operations	$ 14,408	$ 75,160	$ 59,716	$ 37,575
Net income (loss)	$ (19,493)	$ 34,564	$ 20,920	$ 14,230
Income (loss) available (applicable) to common stockholders	$ (28,459)	$ 22,270	$ 11,607	$ 4,915
Basic and diluted:				
Net income (loss) available (applicable) to common stockholders(1)	$ (0.31)	$ 0.21	$ 0.11	$ 0.04
2006:				
Total revenues	$ 85,915	$ 87,915	$ 89,650	$ 124,762
Income from operations	$ 3,468	$ 6,757	$ 8,576	$ 18,180
Net income (loss)	$ 8,383	$ 5,649	$ 4,895	$ (3,306)
Income (loss) available (applicable) to common stockholders	$ 8,383	$ 5,649	$ 4,895	$ (7,273)
Basic and diluted:				
Net income (loss) available (applicable) to common stockholders(1)	$ 0.12	$ 0.08	$ 0.07	$ (0.10)

(1) Income (loss) available (applicable) to common stockholders for each quarter is computed using the weighted-average number of shares outstanding during the quarter, while earnings per share for the fiscal year is computed using the weighted-average number of shares outstanding during the year. Thus, the sum of income (loss) available (applicable) to common stockholders for each of the four quarters may not equal the fiscal year amount.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 7, 2008.

SANDRIDGE ENERGY, INC.

By /s/ Tom L. Ward
Tom L. Ward, Chairman of the Board
and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 7, 2008.

Signature	Title	Date
* Tom L. Ward	President, Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	March 7, 2008
* Dirk M. Van Doren	Chief Financial Officer and Executive Vice President (Principal Financial Officer)	March 7, 2008
* Randall D. Cooley	Senior Vice President Accounting (Principal Accounting Officer)	March 7, 2008
* Dan Jordan	Director	March 7, 2008
* Bill Gilliland	Director	March 7, 2008
* Roy T. Oliver, Jr.	Director	March 7, 2008
* Stuart W. Ray	Director	March 7, 2008
* D. Dwight Scott	Director	March 7, 2008

*	Director	March 7, 2008
Jeff Serota		

*By: /s/ V. Bruce Thompson

EXHIBIT INDEX

Exhibit Number	Description	Filed Herewith(*) or Incorporated by Reference to Exhibit No.	File Number
3.1	Certificate of Incorporation	3.1 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
3.2	Certificate of Designation of convertible preferred stock	3.2 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
3.3	Bylaws	3.3 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
4.1	Specimen Stock Certificate representing common stock	4.1 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
4.2	Resale Registration Rights Agreement, dated December 21, 2005, by and between SandRidge Energy, Inc. (as successor by merger to Riata Energy, Inc.) and Banc of America Securities, LLC	4.2 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
4.2.1	Form of Consent to Amend December 21, 2005 Resale Registration Rights Agreement, dated June 13, 2006	4.11 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
4.2.2	Form of Consent to Amend December 21, 2005 Resale Registration Rights Agreement, dated April 23, 2007	4.12 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
4.2.3	Form of Consent to Amend December 21, 2005 Resale Registration Rights Agreement, dated October 4, 2007	4.13 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
4.3	Registration Rights Agreement, dated November 21, 2006, by and among SandRidge Energy, Inc. (as successor by merger to Riata Energy, Inc.) and the Purchasers party thereto	4.3 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
4.3.1	Form of Consent to Amend November 21, 2006 Registration Rights Agreement, dated October 4, 2007	4.14 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
4.4	Securities Purchase Agreement, dated November 21, 2006, by and among SandRidge Energy, Inc. (as successor by merger to Riata Energy, Inc.) and the Purchasers party thereto	4.4 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
4.5	Specimen Stock Certificate representing convertible preferred stock	4.5 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
4.6	Form of Warrant to Purchase Convertible Preferred Stock	4.6 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956

4.7	Amended and Restated Shareholders Agreement, dated April 4, 2007, among SandRidge Energy, Inc. (as successor by merger to Riata Energy, Inc.) and certain shareholders	4.7 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
4.8	Registration Rights Agreement, dated March 20, 2007, by and among SandRidge Energy, Inc. and the several purchasers party thereto	4.8 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
4.8.1	Form of Consent to Amend March 20, 2007 Registration Rights Agreement, dated October 4, 2007	4.15 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
4.9	Stock Purchase Agreement, dated February 12, 2007, by and among SandRidge Energy, Inc. and each of the investors signatory thereto	4.9 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
4.10	Shareholders Agreement, dated March 20, 2007, by and among SandRidge Energy, Inc. and certain common shareholders	4.10 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956

Exhibit Number	Description	Filed Herewith(*) or Incorporated by Reference to Exhibit No.	File Number
10.1	Executive Nonqualified Excess Plan	*	
10.2	2005 Stock Plan of SandRidge Energy, Inc.	10.2 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
10.2.1	Form of Restricted Stock Award Agreement under 2005 Stock Plan	*	
10.3	Employment Participation Plan of SandRidge Energy, Inc.	10.3 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
10.4	Well Participation Plan of SandRidge Energy, Inc	10.4 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
10.5.1	Employment Agreement of Tom L. Ward, dated June 8, 2006	10.11 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
10.5.2	Employment Agreement of Larry K. Coshow, dated September 2, 2006	10.12 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
10.6	Form of Indemnification Agreement for directors and officers	10.5 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
10.7	Senior Credit Facility, dated November 21, 2006, by and among SandRidge Energy, Inc. (as successor by merger to Riata Energy, Inc.) and Bank of America, N.A., as Administrative Agent and Banc of America Securities LLC as Lead Arranger and Book Running Manager	10.6 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
10.7.1	Amendment No. 1 to Senior Credit Facility, dated November 21, 2006 by and among SandRidge Energy, Inc.	10.9 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
10.7.2	Amendment No. 2 to Senior Credit Facility, dated November 21, 2006	10.10 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
10.8	Senior Bridge Facility, dated November 21, 2006, by and among SandRidge Energy, Inc. (as successor by merger to Riata Energy, Inc.) and Banc of America Bridge LLC, as the Initial Bridge Lender and Banc of America Securities LLC, Credit Suisse Security, Goldman, Sachs Credit Partners L.P., and Lehman Brothers, Inc. as joint lead arrangers and book runners	10.7 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
10.9	Credit Agreement, dated March 22, 2007 by and among SandRidge Energy, Inc. and Bank of America, N.A., as Administrative Agent and Banc of America Securities LLC as Lead Arranger	10.8 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
10.10			333-148956

	Partnership Interest Purchase Agreement, dated November 21, 2005 by and among Riata Energy, Inc. and Matthew McCann	10.13 to Registration Statement on Form S-1 filed on January 30, 2008	
10.11	Purchase and Sale Agreement, dated December 4, 2005 by and between Gillco Energy, LP, as Seller and Riata Energy, Inc., Riata Piceance, LLC, MidContinent Resources, LLC, and ROC Gas Company, as Buyer	10.14 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
10.12	Purchase and Sale Agreement, dated December 4, 2005 by and between Wallace Jordan, LLC and Daniel White Jordan, as Sellers and Riata Energy, Inc., Sierra Madera CO 2 Pipeline, LLC, Riata Piceance, LLC, and ROC Gas Company, as Buyers	10.15 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
10.13	Purchase and Sale Agreement, dated August 29, 2006 by and among Alsate Management and Investment Company and Longfellow Ranch Partners, LP	10.16 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
10.14	Purchase and Sale Agreement, dated June 7, 2007 by and between Wallace Jordan, LLC and SandRidge Energy, Inc.	10.17 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956

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Exhibit Number	Description	Filed Herewith(*) or Incorporated by Reference to Exhibit No.	File Number
10.15	Office Lease Agreement, dated March 6, 2006 by and between 1601 Tower Properties, L.L.C. and Riata Energy, Inc.	10.18 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
10.15.1	First Amendment, dated October 19, 2006 to Office Lease Agreement, dated March 6, 2006	10.19 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
10.15.2	Second Amendment, dated January 26, 2007 to Office Lease Agreement	10.20 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
10.16	Letter Agreement for Acquisition of Properties, dated September 21, 2007 by and between SandRidge Energy, Inc., Longfellow Energy, LP, Dalea Partners, LP and N. Malone Mitchell, 3rd	10.21 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
21.1	Subsidiaries of SandRidge Energy, Inc.	21.1 to Registration Statement on Form S-1 filed on January 30, 2008	333-148956
23.1	Consent of PricewaterhouseCoopers LLP	*	
23.2	Consent of DeGolyer and MacNaughton	*	
23.3	Consent of Netherland, Sewell & Associates, Inc.	*	
23.4	Consent of Harper & Associates, Inc.	*	
24.1	Power of Attorney (included on signature page)	*	
31.1	Section 302 Certification Chief Executive Officer	*	
31.2	Section 302 Certification Chief Financial Officer	*	
32.1	Section 906 Certifications of Chief Executive Officer and Chief Financial Officer	*	

Management contract or compensatory plan or arrangement

Note: Debt instruments of the Company defining the rights of long-term debt holders in principal amounts not exceeding 10 percent of its consolidated assets have been omitted and will be provided to the Commission upon request.