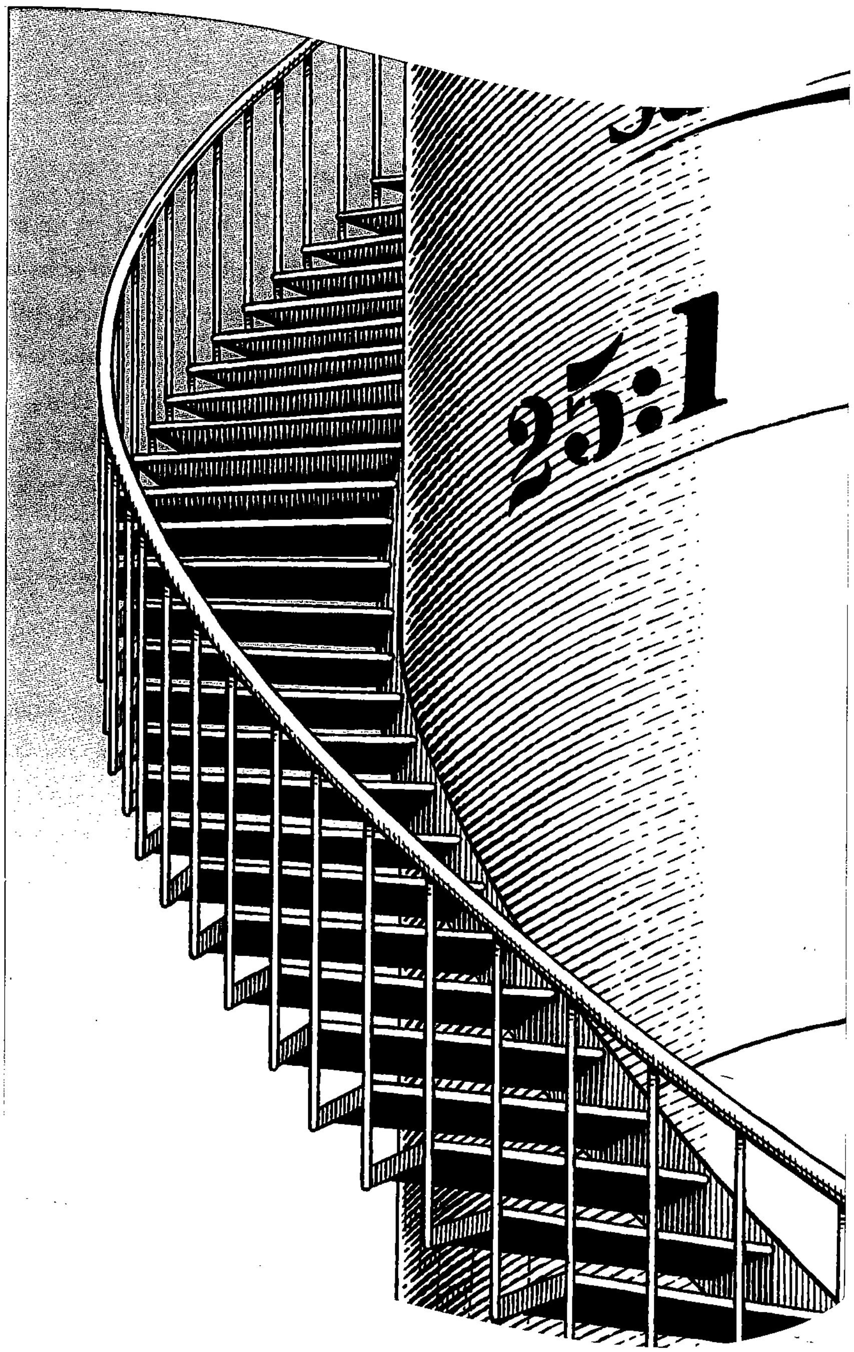
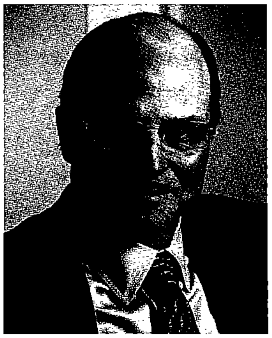
2010 ANNUAL REPORT



SandRidge

Based on the increasing divergence between the relative values of oil and natural gas – currently approximately 25:1 – the decision by SandRidge to shift our focus to oil seemed only natural.


SandRidg
25:1



Fellow Shareholders:

SandRidge is an Oil Company

In 2010, SandRidge Energy successfully completed its transformation from a company that was focused primarily on natural gas two years ago to one that will derive approximately 80 percent of its 2011 revenues from oil and dedicate essentially all of its 2011 drilling budget to oil. Shifting to oil was viewed by many as a contrarian move; however, we believed it natural based on the increasing divergence between the relative values of natural gas and oil. We can now look back and see that we not only made the right call on commodities, but we did so on a scale that transformed our company.

"Shifting to oil was viewed by many as a contrarian move; however, we believed it natural based on the increasing divergence between the relative values of natural gas and oil."

Oil and natural gas are traditionally compared on an energy equivalency basis using a ratio of six thousand cubic feet of natural gas (Mcf) to one barrel of oil (Bbl), or six-to-one (6:1). On a valuation basis, however, with natural gas prices currently hovering around $4.00 per Mcf and oil in the $100 per barrel range, the valuation ratio is approximately 25:1. One barrel of oil is now worth the same as 25 Mcf of gas, making oil a significantly more valuable commodity. As the supply and demand fundamentals for oil remain robust, we are convinced the valuation ratio will remain high and our focus on oil production will provide a stronger, more secure revenue stream for the company.

Tom L. Ward
Chairman and CEO

Proven Shallow Carbonate Reservoirs Mean Low Cost

Controlling costs is the key to success in our oil drilling program. By pursuing shallow, permeable carbonate reservoirs, we are able to drill wells quickly and at a low cost. Shallow carbonate targets mean lower horsepower requirements for drilling and low pressure pumping equipment during the completion process. Since most of the industry has moved to deeper, tighter rock formations, which have higher horsepower requirements for hydraulic fracturing, the low pressure equipment we need is plentiful and readily available. In addition, we also own 31 drilling rigs,

25:1

As natural gas prices hover around $4.00 per Mcf and oil remains in the $100 per barrel range, the current valuation ratio between natural gas and oil is approximately 25:1. One barrel of oil is now worth the same as 25 Mcf of gas, making oil a significantly more valuable commodity.

providing the flexibility to move on and off site quickly. As a result, our drilling costs have not increased appreciably since early 2009, and we do not expect significant increases going forward.

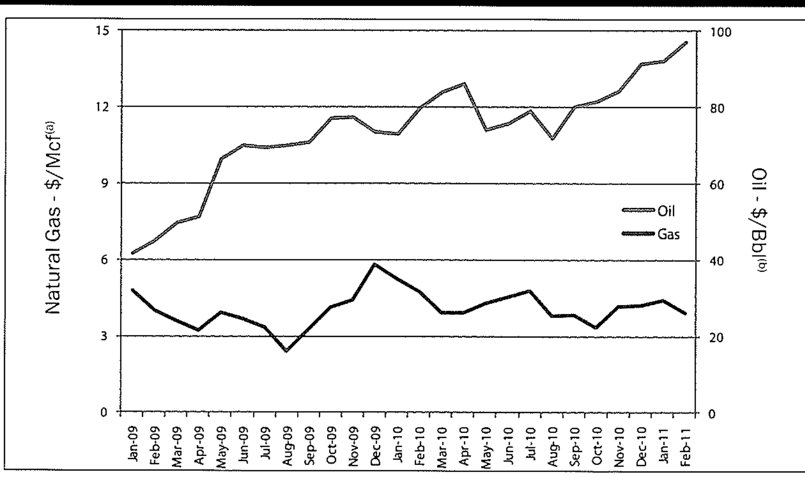
In addition to our emphasis on low costs, we also look to drill in areas with decades of proven production. The Central Basin Platform of the Permian Basin, for example, has been actively drilled since the early 1900s and has produced more than 13 billion barrels of oil. Reserve estimates based on decades of production history indicate the area still contains substantial amounts of oil in multiple reservoirs. Our focus on cost control in proven low risk reservoirs, combined with an aggressive hedging program, enable SandRidge to lock in exceptional rates of return.

"...our drilling costs have not increased appreciably since early 2009, and we do not expect significant increases going forward."

Permian Basin Oil

In late 2009, we acquired properties in the Central Basin Platform of the Texas Permian Basin from Forest Oil. We followed this up with the acquisition of Arena Resources in July 2010. These two transactions provided SandRidge with 149 million barrels of oil equivalent (MMboe) of proved reserves and 16,100 barrels of oil equivalent per day (Boepd) of production—75 percent of which is oil. Our total investment of less than \$1.9 billion is now worth approximately \$3.8 billion[1] clearly illustrating our ability to execute and enhance value in our core areas.

Diverging Value of Natural Gas to Oil
As the supply and demand fundamentals of oil remain robust, we expect the divergence between the relative values of natural gas and oil that began two years ago to continue favoring oil in the future.

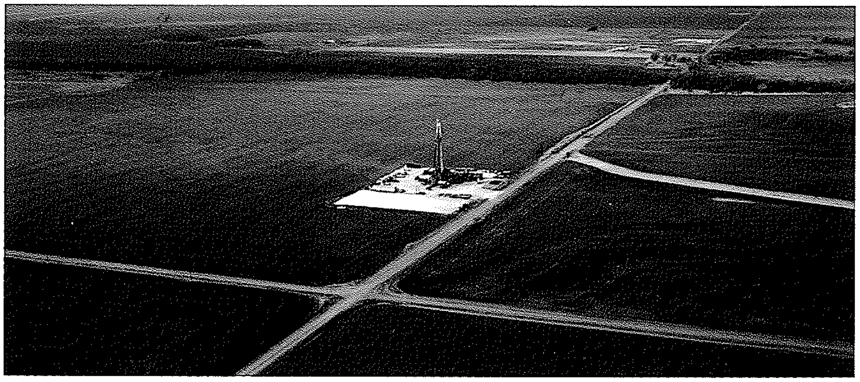


(a) Henry Hub spot prices for the last day of each month
(b) West Texas Intermediate spot prices for the last day of each month

The largest portion of our 2011 drilling budget will be dedicated to the Central Basin Platform where we expect to drill

800

SandRidge is the most active driller in the Central Basin Platform of the Texas Permian Basin. We expect to drill more than 800 wells in 2011 in this oil rich region, where our wells are expected to produce an average of approximately 83,000 Boe per well and achieve a 90% rate of return(2).



more than 800 wells using 16 rigs, making SandRidge the most active driller in this oil rich region. A majority of our wells are drilled to depths of 4,000 to 8,000 feet, and are often completed in multiple zones, with the San Andres and Clear Fork being the primary targets. The average well costs approximately $760,000 and takes four to eight days to drill, depending on the formation being targeted. These wells are expected to produce an average of about 83,000 Boe per well and achieve a 90 percent rate of return(2).

Horizontal Mississippian Oil

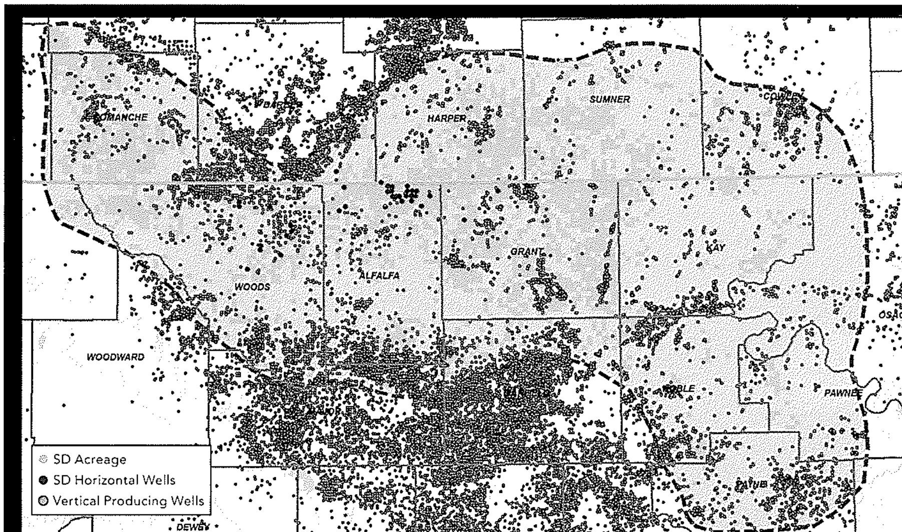
Our second core area is the horizontal Mississippian play in Northern Oklahoma and Southern Kansas. We are excited about the potential of the Mississippian formation with its shallow carbonate reservoirs and decades of production history. Our early and aggressive entry into this play enabled us to keep our lease costs under $200 per acre, which is in stark contrast to the entry cost of many of the recent, higher profile plays now prominent in our industry, where acreage costs have been 10 to 100 times higher.

Horizontal wells drilled in the Mississippian formation reach a total vertical depth of about 6,000 feet and are then drilled another 4,000 feet horizontally, at a cost of $2.7 million(3) per well. With more than 17,000 vertical wells drilled in this area over the last 30 years, we believe the Mississippian has significant scale. Accordingly, we expect to reach 900,000 to 1 million acres of leasehold, which represents the largest land position of any operator. We have identified more than 3,400 potential drilling locations in the Mississippian formation and expect to drill approximately 135 horizontal wells this year using 12 rigs. We expect ultimate recovery to range from 300,000 to 500,000 Boe per well and, based on current commodity prices, these wells to provide a 120 percent rate of return(4).

"We have identified more than 3,400 potential drilling locations in the Mississippian formation and expect to drill approximately 135 horizontal wells this year using 12 rigs."

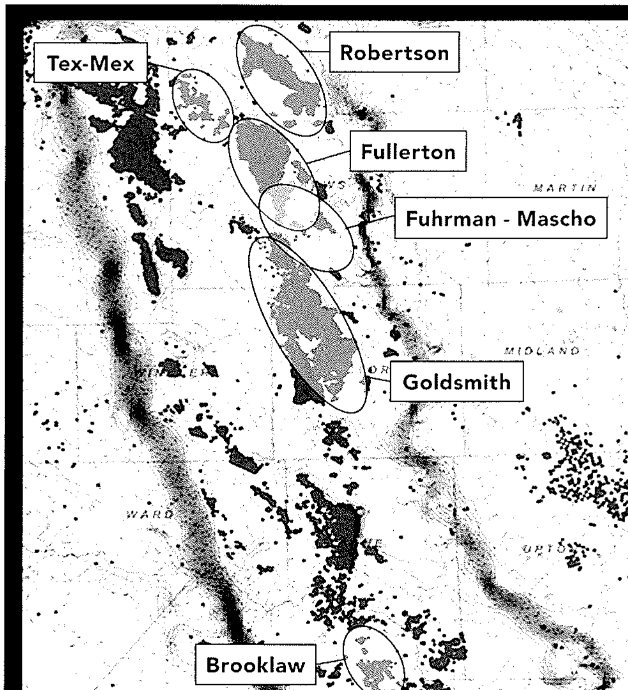
120%

We expect to reach 900,000 to 1,000,000 acres of leasehold in the horizontal Mississippian play of Northern Oklahoma and Southern Kansas, representing the largest land position of any operator. Based on current commodity prices, our horizontal wells in this area are expected to provide a 120% rate of return[(4)].



HORIZONTAL MISSISSIPPIAN OIL PLAY

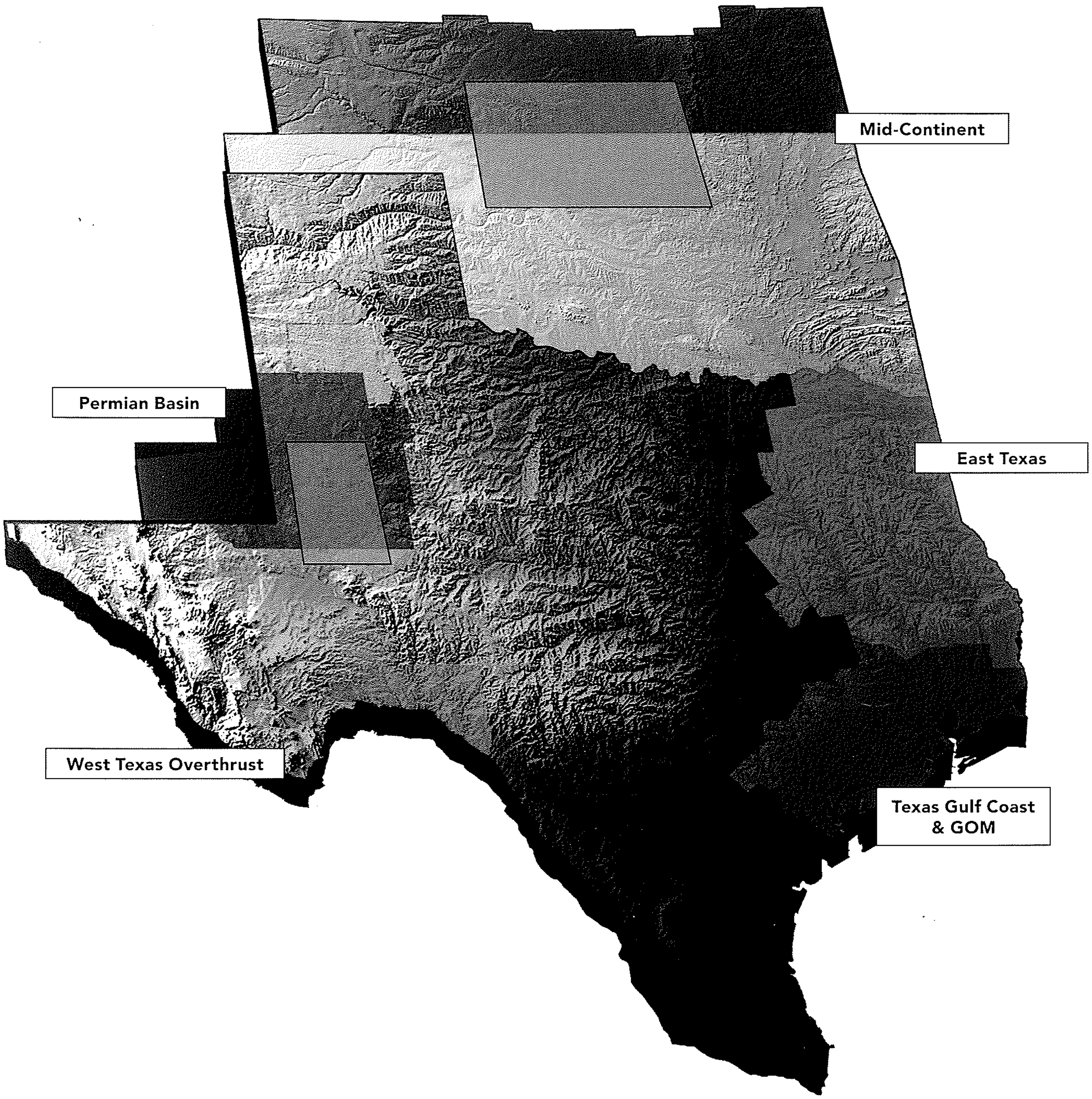
Our early and aggressive entry into the horizontal Mississippian oil play, with its shallow carbonate reservoirs and decades of production history, has enabled SandRidge to keep our lease costs under $200 per acre, which is in stark contrast to the entry cost of many of the recent, higher profile plays now prominent in our industry, where acreage costs have been 10 to 100 times higher.



CENTRAL BASIN PLATFORM

Actively drilled since the early 1900s, the Central Basin Platform has produced more than 13 billion barrels of oil. Reserve estimates based on decades of production history indicate the area still contains substantial amounts of oil in multiple reservoirs. SandRidge has identified approximately 7,700 future drilling locations with high rates of return and predictable production profiles.

SandRidge Energy's primary areas of activity are in the Central Basin Platform of the Texas Permian Basin and the horizontal Mississippian formation of Northern Oklahoma and Southern Kansas. The company also has operations in East Texas, the Gulf Coast, the Gulf of Mexico and the West Texas Overthrust.



Not Just Oil: Significant Natural Gas Upside Remains

SandRidge has approximately 8,000 natural gas drilling opportunities across Oklahoma, East Texas, the Gulf Coast, the Gulf of Mexico and in the West Texas Overthrust. However, as our oil rich assets produce the highest return on our drilling capital, we have drastically curtailed our natural gas drilling to the point where we do not expect to drill any new gas wells this year. When natural gas prices reach an appropriate level, our extensive asset base provides a tremendous opportunity to either increase natural gas production or use these gas assets as a source of capital.

"With the transformation to oil essentially complete, we now have an exceptional platform of conventional assets with predictable production curves that we are able to drill at a low cost, resulting in high rates of return."

Oil Hedges

We continue to actively hedge and lock in cash flows on our high rate of return oil projects. For 2011, we have over 75 percent of our estimated production hedged at prices just over $86 per barrel for oil and $4.69 per Mcf for natural gas. We have an additional 20 million barrels of oil hedged through 2013 at an average price of $91 per barrel and we continue to hedge aggressively as oil prices, currently around $100 per barrel, continue to improve.

While hedging our production at current commodity prices allows us to lock in revenues, it is our ability to control our drilling costs that makes our hedging program work. Because we have some certainty about our future drilling costs, we are comfortable hedging two to three years of future production, locking in positive revenue and returns.

Increased Oil Production Equals Increased Shareholder Value

The changes we have implemented over the last two years have made this an exciting time for SandRidge. With the transformation to oil essentially complete, we now have an exceptional platform of conventional assets with predictable production curves that we are able to drill at a low cost, resulting in high rates of return. Our two sizable oil plays in the Central Basin Platform and the horizontal Mississippian

66%

At a time when oil is in high demand worldwide and is becoming increasingly more difficult to find and produce, we expect to grow our oil production by 66% in 2011, enabling SandRidge to generate higher revenues and deliver increased value to our shareholders.

formation provide a large inventory of high return oil drilling opportunities with decades of known production history.

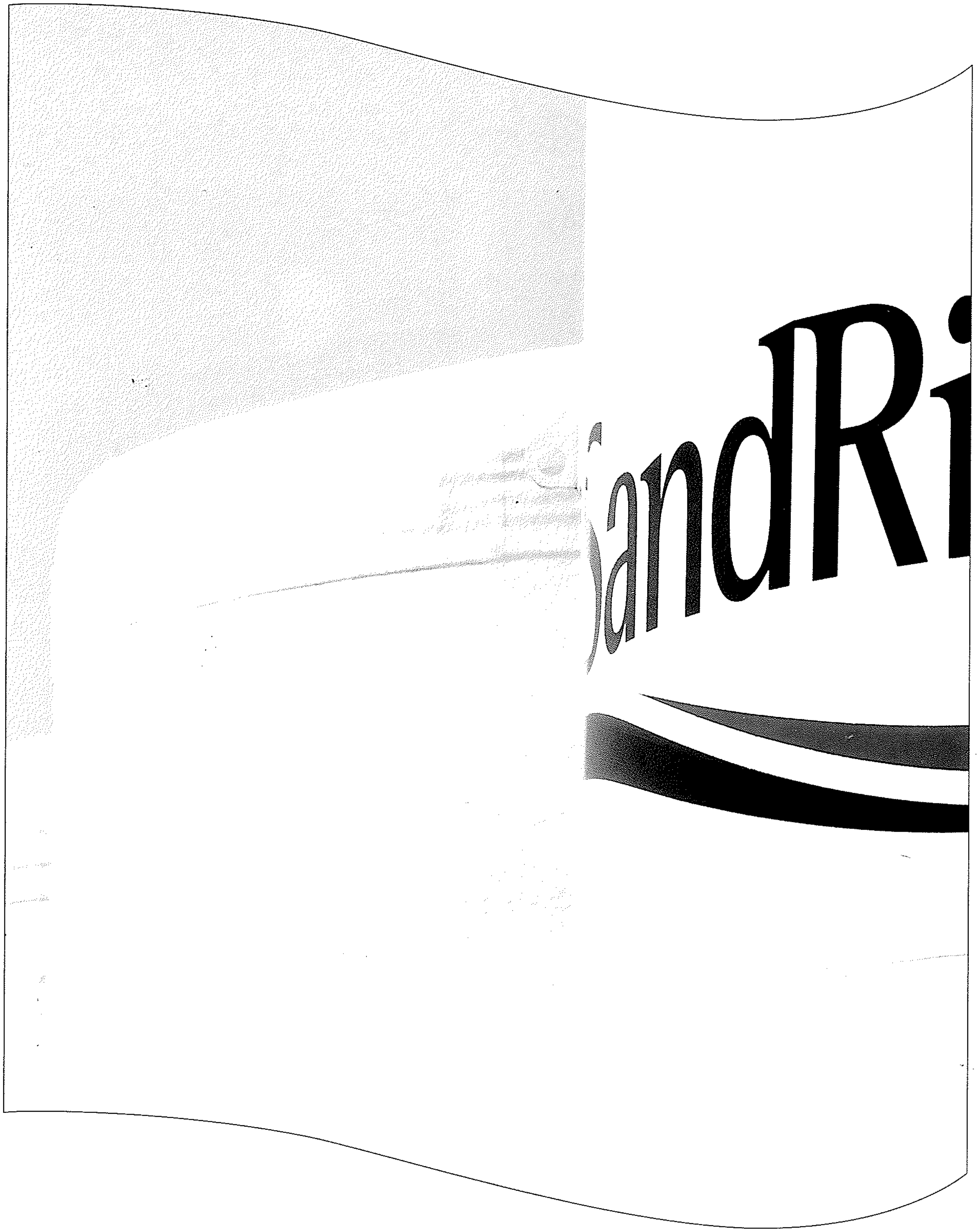
At a time when oil is in high demand worldwide and is progressively becoming more difficult to find and produce, SandRidge increased oil production last year by 155 percent over 2009. In 2011, we expect to further increase our oil production by another 66 percent over 2010. When considering the current valuation ratio of oil to natural gas, our ability to substantially grow our oil production clearly enables SandRidge to generate higher revenues and deliver increased value to our shareholders. When combined with our ability to quickly capture value on our natural gas assets should prices improve, our successful transformation to oil has put SandRidge in an extremely positive position for the future.

"When considering the current valuation ratio of oil to natural gas, our ability to substantially grow our oil production clearly enables SandRidge to generate higher revenues and deliver increased value to our shareholders."

I would like to recognize the expertise and counsel provided by our board of directors, the leadership of our senior staff and the superior performance of our talented employees, whose combined efforts made the transformation to oil possible. Thank you to our shareholders for offering the ultimate vote of confidence through your continued faith in the future of our company. The hard choice to move away from natural gas in early 2009 is now paying dividends as the company is poised to deliver tremendous growth in 2011 and beyond.

Tom L. Ward
Chairman and Chief Executive Officer

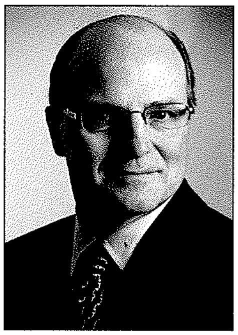
(1) Based on NYMEX strip prices as of February 7, 2011, with hedging adjustments.
(2) Based on NYMEX strip prices as of February 14, 2011 and a type curve estimated ultimate recovery of 83,000 Boe.
(3) Includes capital expenditure allocation for water disposal facilities.
(4) Based on NYMEX strip prices as of February 14, 2011 and a type curve estimated ultimate recovery of 409,000 Boe.



2011

Our successful transformation to oil has put SandRidge in an extremely positive position for the future. The hard choice to move away from natural gas in early 2009 is now paying dividends as the company is poised to deliver tremendous growth in 2011 and beyond.

SANDRIDGE BOARD OF DIRECTORS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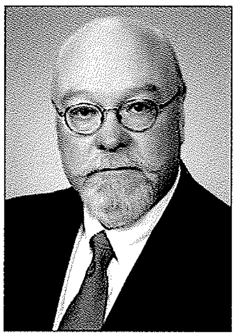
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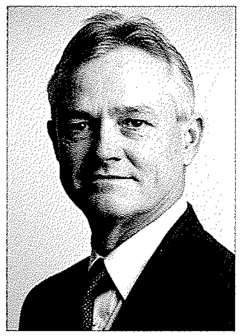
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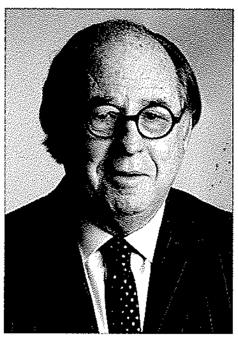
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1 Tom L. Ward
Chairman and Chief Executive Officer

2 Jim J. Brewer [a]
President – J-Brex Company

3 Everett R. Dobson [a]
Chairman – Dobson Technologies

4 William A. Gilliland [b]
Managing Partner – Gillco Energy, LP & Gillco Investments, LP

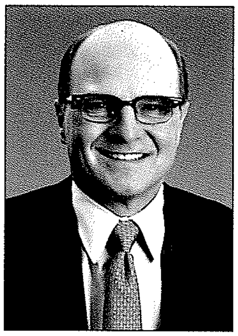
5 Daniel W. Jordan [b,c]
Private Investor

6 Roy T. Oliver [b,c]
President – R.T. Oliver Investments, Inc.

7 Jeffrey S. Serota [a]
Senior Partner – Ares Management LLC

a. Audit Committee
b. Compensation Committee
c. Nominating and Governance Committee

MANAGEMENT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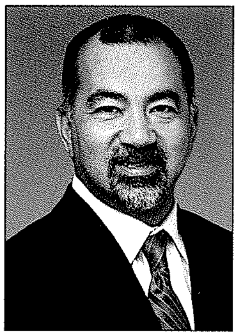
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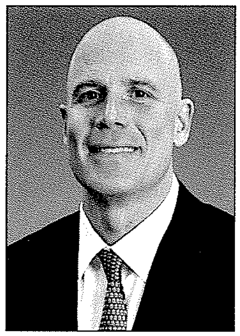
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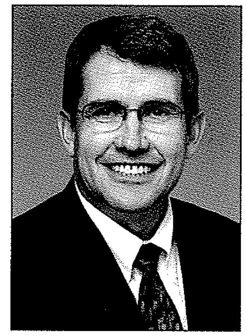
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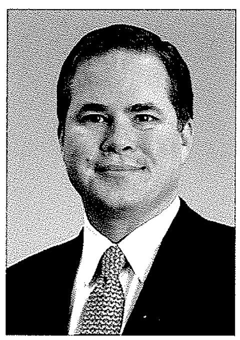
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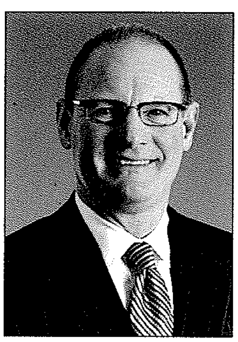
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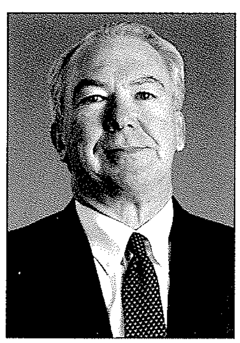
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1 Tom L. Ward
Chairman and Chief Executive Officer

2 Matthew K. Grubb
President and Chief Operating Officer

3 James D. Bennett
Executive Vice President and Chief Financial Officer

4 Todd N. Tipton
Executive Vice President – Exploration

5 Rodney E. Johnson
Executive Vice President – Reservoir Engineering

6 Wayne C. Chang
Senior Vice President – SandRidge Energy, Inc. and President - SandRidge Midstream, Inc.

7 Randall D. Cooley
Senior Vice President – Accounting

8 Philip T. Warman
Senior Vice President, General Counsel and Corporate Secretary

9 Kevin R. White
Senior Vice President – Business Development

10 Mary L. Whitson
Senior Vice President – Human Resources

11 Thomas L. (Lon) Winton
Senior Vice President – Information Technology and Chief Information Officer

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

Form 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2010

OR

☐ **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: 001-33784

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

Delaware **(State or other jurisdiction of incorporation or organization)**	**20-8084793** **(I.R.S. Employer Identification No.)**
123 Robert S. Kerr Avenue **Oklahoma City, Oklahoma** **(Address of principal executive offices)**	**73102** **(Zip Code)**

(405) 429-5500
(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 ☑ No ☐

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 ☐ No ☑

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 ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

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. ☐

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 the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑	Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if smaller reporting company)	Smaller reporting company ☐

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

The aggregate market value of our common stock held by non-affiliates on June 30, 2010 was approximately $1.0 billion based on the closing price as quoted on the New York Stock Exchange. As of February 18, 2011, there were 410,263,660 shares of our common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company's definitive proxy statement for the 2011 Annual Meeting of Stockholders are incorporated by reference in Part III.

SANDRIDGE ENERGY, INC.

2010 ANNUAL REPORT ON FORM 10-K

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This Annual Report on Form 10-K ("Form 10-K") includes certain statements that may be deemed to be "forward-looking" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). We refer you to "Risk Factors" in Item 1A of Part I and to "Management's Discussion and Analysis of Financial Condition and Results of Operations — Cautionary Statement Concerning Forward-Looking Statements" in Item 7 of Part II of this Form 10-K for a discussion of factors that could cause actual results to differ materially from any such forward-looking statements.

PART I

Item 1. *Business*

General

SandRidge Energy, Inc., is an independent oil and natural gas company headquartered in Oklahoma City, Oklahoma concentrating on development and production activities related to the exploitation of our significant holdings in West Texas and the Mid-Continent area of Oklahoma and Kansas. Our primary areas of focus in West Texas are the Permian Basin and the West Texas Overthrust (the "WTO"). In the Permian Basin, we control approximately 244,700 net acres in West Texas and New Mexico. Our oil properties in the Permian Basin include properties acquired in December 2009 from Forest Oil Corporation and one of its subsidiaries (collectively, "Forest") in conjunction with our strategic shift in focus to oil development and production, and properties formerly owned by Arena Resources, Inc. ("Arena"), which we acquired in July 2010. The WTO, which includes the Piñon gas field, is a natural gas-prone region in Pecos County and Terrell County, Texas where we have approximately 501,100 net acres under lease. Our primary area of focus in the Mid-Continent area is the Mississippian formation, a carbonate oil-bearing structure where we had approximately 573,800 net acres under lease at December 31, 2010. We also own and operate other interests in the Mid-Continent, Cotton Valley Trend in East Texas, Gulf Coast and Gulf of Mexico.

As of December 31, 2010, our total estimated proved reserves were 545.9 MMBoe or 3,275.3 Bcfe, of which approximately 46% were oil. The reports covering 96.5% of these estimated proved reserves were prepared by third party engineers. As of December 31, 2010, we had a total of 5,323 gross (4,541.3 net) producing wells, substantially all of which we operate, and had approximately 1,982,000 gross (1,492,000 net) total acres under lease. As of December 31, 2010, we had 16 rigs drilling in the Permian Basin, 7 rigs drilling in the Mississippian formation and 1 rig drilling in the WTO.

We also operate businesses that are complementary to our primary development and production activities which provide us with operational flexibility and an advantageous cost structure. We own related gas gathering and treating facilities, a gas marketing business and an oil field services business, including our wholly owned drilling rig business, Lariat Services, Inc. ("Lariat"). As of December 31, 2010, our drilling rig fleet consisted of 31 rigs, all of which were operational. We also capture and transport CO_2 to the Permian Basin for use in tertiary recovery projects.

Our principal executive offices are located at 123 Robert S. Kerr Avenue, Oklahoma City, Oklahoma 73102 and our telephone number is (405) 429-5500. We make available free of charge on our website at *http://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 ("SEC"). 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 or accessed via the SEC's website address at *http://www.sec.gov*.

References to "SandRidge," "us," "we," "Company" and "our" in this report refer to SandRidge Energy, Inc., together with its subsidiaries. "SandRidge CO_2" refers to our wholly owned subsidiary SandRidge CO_2, LLC, and "SandRidge Tertiary" refers to our wholly owned subsidiary SandRidge Tertiary, LLC.

Business Strategy

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

- *Concentrate in Core Operating Areas.* Our primary areas of operation are West Texas and the Mid-Continent area of Oklahoma and Kansas, which includes the Mississippian formation.

Concentrating our drilling and producing activities in these core areas allows us to further build and utilize our technical expertise in order to interpret specific geological and operational trends. Further, by concentrating in these core areas we are able to achieve economies of scale and breadth of operations, both of which help us to control our costs. Operating in multiple core areas allows us to balance our portfolio toward the goal of consistent production and reserve growth.

- *Focus on Conventional Reservoirs.* We focus our development efforts primarily in areas with conventional, shallow, low-cost, permeable carbonate reservoirs with decades of production history. The nature of these reservoirs allows us to execute low-risk, repeatable drilling programs with predictable production profiles and a higher certainty of economic returns. Further, due to these low pressure and shallow characteristics, we are able to mitigate rising service costs.

- *Maintain Flexibility.* We have multi-year inventories of both oil and natural gas drilling locations within our core operating areas. Additionally, we maintain our own fleet of drilling rigs through Lariat. Maintaining inventories of both oil and natural gas drilling locations as well as our own drilling rigs allows us to efficiently direct capital toward projects with the most attractive returns.

- *Mitigate Commodity Price Risk.* We enter into derivative contracts in order to mitigate commodity price volatility inherent in the oil and natural gas industry. By increasing the predictability of cash inflows for a portion of our future production, we are better able to ensure funding for our longer term development plans and rates of return associated with those plans.

- *Monetize Non-Core Assets.* We periodically evaluate our properties to identify opportunities to monetize non-core assets in order to fund or accelerate development within our areas of focus. We sold non-core properties located in the Cana Shale play in Northwest Oklahoma and in the Permian Basin during the third and fourth quarters of 2010, respectively, and also entered into an agreement for another divesture of Permian Basin non-core assets during the fourth quarter of 2010. Proceeds realized from these transactions will be used to pay down amounts outstanding under our senior secured revolving credit facility (the "senior credit facility").

Recent Developments

Acquisitions and Divestures

Arena Acquisition. On July 16, 2010, we completed our acquisition of all of the outstanding common stock of Arena (the "Arena Acquisition"). In connection with the acquisition, we issued 4.7771 shares of our common stock and paid $4.50 in cash to Arena stockholders for each outstanding share of unrestricted Arena common stock. In addition, outstanding options to purchase Arena common stock that were deemed exercised pursuant to the merger agreement were converted into shares of our common stock pursuant to a formula in the merger agreement, and outstanding shares of Arena restricted common stock were converted into restricted shares of our common stock pursuant to a formula in the merger agreement. The total purchase price was approximately $1.4 billion.

In conjunction with stockholder approval of the issuance of SandRidge common stock in connection with the acquisition of Arena, our stockholders also approved an amendment to our certificate of incorporation to increase the number of authorized shares of common stock from 400.0 million shares to 800.0 million shares.

Sale of Oklahoma Deep Rights. On August 26, 2010, we sold certain deep acreage rights in the Cana Shale play in Western Oklahoma for estimated net proceeds of $110.0 million, subject to final post-closing adjustments. We retained the shallow rights associated with this acreage.

Sale of Avalon Shale and Bone Springs Assets. On December 10, 2010, we sold approximately 40,000 net acres of non-core assets in the Avalon Shale and Bone Spring reservoirs of the Permian Basin for $110.0 million, subject to post-closing adjustments. There was no production or proved reserves associated with these assets and we retained all rights above and below the Avalon Shale and Bone Spring formations.

Sale of Wolfberry Assets. On January 6, 2011, we sold our Wolfberry assets in the Permian Basin for approximately $155.0 million, subject to post-closing adjustments. The divested properties included approximately 18,400 net acres with production of approximately 1,600 Boe/d.

Sale of New Mexico Assets. On February 24, 2011, we executed a Purchase and Sales Agreement under which we agreed to sell properties in Lea County and Eddy County in New Mexico for $200.0 million. The properties include 23,000 net acres with production of approximately 1,500 Boe/d. We intend to use the cash proceeds to pay down outstanding borrowings under our senior credit facility. We expect the transaction, which is subject to customary closing conditions, to close in April 2011.

Proposed Royalty Trust Offering

On January 5, 2011, we and SandRidge Mississippian Trust I (the "Trust"), a newly formed Delaware statutory trust, filed registration statements with the SEC relating to a proposed public offering of up to $250.0 million in common units representing beneficial interests in the Trust. Prior to the closing of this offering, we intend to convey certain royalty interests to the Trust in exchange for units representing approximately 50% of the beneficial interest in the Trust and the net proceeds of the Trust's public offering. The royalty interests to be conveyed to the Trust would be in certain oil and natural gas properties leased by us in the Mississippian formation in five counties in Northern Oklahoma. There can be no assurance that we will complete this transaction, as it is subject to market conditions and other uncertainties, as well as completion of the SEC review process. If we complete this transaction, we intend to use the net proceeds from the offering to repay borrowings under our senior credit facility and for general corporate purposes.

Equity Transaction

On November 15, 2010, we completed a private placement of 3,000,000 shares of 7.0% convertible perpetual preferred stock for net proceeds of approximately $290.7 million, after deducting initial purchasers' discounts of $9.0 million and other offering expenses.

2011 Budget

On February 24, 2011, we updated 2011 production guidance to 23.3 MMBoe based on 2011 capital expenditure guidance of $1.3 billion. See Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources" for further discussion of our capital expenditures budget.

Our Business Segments and Primary Operations

We operate in three business segments: exploration and production, drilling and oil field services and midstream gas services. Financial information regarding each segment is provided in Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Exploration and Production

We explore for, develop and produce oil and natural gas reserves, with a focus on increasing our reserves and production in the Permian Basin, Mid-Continent and WTO. We operate substantially all of our wells in these areas. We also operate leasehold positions in the Cotton Valley Trend in East Texas, Gulf Coast and Gulf of Mexico.

The following table presents certain information concerning our exploration and production business as of December 31, 2010 unless otherwise noted:

Area	Estimated Net Proved Reserves (MMBoe)	Estimated Net Proved Reserves (Bcfe)	PV-10 (in millions)(1)	Daily Production (MBoe/d)(2)	Daily Production (MMcfe/d)(2)	Reserves/ Production (Years)	Proved Gross Acreage	Proved Net Acreage
Permian Basin	228.3	1,369.8	$3,096.9	28.3	169.4	22.1	336,634	244,671
Mid-Continent	63.0	378.0	656.5	7.4	44.6	23.3	851,054	644,020
WTO	135.7	814.2	157.5	16.0	95.9	23.2	625,623	501,066
East Texas	80.1	480.6	210.1	5.1	30.3	43.0	32,650	26,112
Gulf Coast	7.8	46.8	83.4	3.6	21.6	5.9	54,426	27,750
Gulf of Mexico	7.5	45.0	77.3	1.9	11.4	10.8	71,990	39,427
Tertiary recovery — West Texas	23.4	140.3	226.6	0.6	3.7	106.8	8,661	8,215
Other	0.1	0.6	0.9	—	—	—	940	683
Total	545.9	3,275.3	$4,509.2	62.9	376.9	23.8	1,981,978	1,491,944

(1) PV-10 generally differs from Standardized Measure of Discounted Net Cash Flows ("Standardized Measure") because it does not include the effects of income taxes on future net revenues. For a reconciliation of PV-10 to Standardized Measure, see — "Proved Reserves." Our total Standardized Measure was $3.7 billion at December 31, 2010.

(2) Average daily net production for the month of December 2010.

Permian Basin

The Arena Acquisition in July 2010 continued the expansion of our holdings in the Central Basin Platform ("CBP"), a part of the Permian Basin in West Texas, and added significant Permian Basin production from the Midland and Delaware Basins in Texas as well as the Northwest Shelf in New Mexico. Reserves and associated production in this area are predominantly oil.

The primary reservoirs in the CBP are the dolomites and limestones of the San Andres and Clear Fork formations. To date, the San Andres and Clear Fork zones have produced more than 4.0 and 1.8 billion barrels of oil, respectively, with well depths typically ranging from 4,500 to 8,000 feet. Our properties in the CBP are positioned for infill and step-out drilling to target these reservoirs in several of the major CBP fields, such as the Fuhrman Mascho, Goldsmith, Fullerton, Tex-Mex, Martin and Robertson fields.

As of December 31, 2010, our estimated net proved reserves in the Permian Basin were 228.3 MMBoe or 1,369.8 Bcfe, 56% of which were proved undeveloped reserves, based on estimates provided by our independent oil and natural gas consulting firms, Lee Keeling and Associates, Inc. ("Lee Keeling") and Netherland, Sewell & Associates, Inc. ("Netherland Sewell"). Our interests in the Permian Basin as of December 31, 2010 included 3,285 gross (3,128.1 net) producing wells with an average working interest of 94%. Our average daily net production for the month of December 2010 was approximately 28.3 MBoe or 169.4 MMcfe per day. We were operating 16 rigs in the Permian Basin as of December 31, 2010 and drilled 484 wells in this area during 2010.

Mid-Continent

We own interests in properties in Oklahoma, Arkansas and Southern Kansas that make up our Mid-Continent area. As of December 31, 2010, we held interests in 851,054 gross (644,020 net) leasehold and option acres in these areas. As of December 31, 2010, our estimated proved reserves in the Mid-Continent area were 63.0 MMBoe or 378.0 Bcfe, 63.8% of which were proved undeveloped reserves, based on estimates prepared by Netherland Sewell and our internal engineers. Our average daily net production for the month of December 2010 was approximately 7.4 MBoe or 44.6 MMcfe per day. We were operating 9 rigs in the Mid-Continent area as of December 31, 2010 and drilled or participated in the drilling of 49 wells in this area during 2010.

Mississippian Formation. The Mississippian formation within the Mid-Continent area is located on the Anadarko Shelf in Northern Oklahoma and Southern Kansas. The top of this expansive carbonate hydrocarbon system is encountered between 4,000 and 6,000 feet and lies stratigraphically between the Pennsylvanian-aged Morrow Sand and the Devonian-aged Woodford Shale formations. The Mississippian formation may reach 1,000 feet in gross thickness and the targeted porosity zone is between 50 and 100 feet in thickness. The formation's geology is well understood as a result of the thousands of vertical wells drilled and produced there since the 1940s. Beginning in 2007, the application of horizontal cased-hole drilling and multi-stage hydraulic fracturing treatments have demonstrated the potential for extracting significant additional quantities of oil and natural gas from the formation.

Since the beginning of 2009, there have been over 95 horizontal wells drilled and completed in the Mississippian formation in Oklahoma. Since 2009, we have drilled, as operator, 37 horizontal wells throughout the Mississippian formation, of which 29 were producing and 8 were awaiting completion at December 31, 2010. We had seven horizontal rigs drilling in the formation as of December 31, 2010. While horizontal wells are more expensive than vertical wells, a horizontal well bore increases the production of hydrocarbons and adds significant recoverable reserves per well. In addition, an operator can drill one horizontal well, which is the equivalent of several vertical wells. We had 684,993 gross (573,757 net) acres leased in the Mississippian formation in Oklahoma and Kansas as of December 31, 2010.

West Texas Overthrust

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 primary reservoir rocks in the WTO range in depth from 2,000 to 17,000 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 under-explored. The high CO_2 content of the natural gas, lack of infrastructure in the region, historical limitations of conventional subsurface geological and geophysical methods and commodity prices have combined to discourage exploration of the area. Our access to and control of the necessary infrastructure combined with the application of modern seismic techniques allow us to continue to identify exploration and development opportunities in the WTO. As of December 31, 2010, we had acquired, processed and interpreted 1,300 square miles of 3-D seismic data in the WTO. We believe the use of this data will lower exploratory risk and improve completion efficiency by identifying structural detail of potential reservoirs.

Piñon Field. The Piñon Field lies along the leading edge of the WTO in Pecos County. The primary reservoirs are the Tesnus sands (depths ranging from 3,500 to 5,000 feet), the Warwick Caballos chert (depths ranging from 5,000 to 8,000 feet) and the Dugout Creek Caballos chert (depths ranging from 7,000 to 10,000 feet). As of December 31, 2010, our estimated proved oil and natural gas reserves in the Piñon Field were 135.4 MMBoe or 812.4 Bcfe, 53% of which were proved undeveloped reserves based on estimates prepared by Netherland Sewell. Our interests in the Piñon Field as of December 31, 2010 included 892 gross (745.6 net) producing wells and a 96% average working interest in the producing area of the Piñon Field. We were operating 1 drilling rig in the Piñon Field as of December 31, 2010 and we drilled 112 wells in this field during 2010.

Century Plant. In order to facilitate expansion of CO_2 treating capacity in the WTO, we are constructing a CO_2 treatment plant in Pecos County, Texas (the "Century Plant"), and associated compression and pipeline facilities pursuant to a construction agreement with a subsidiary of Occidental Petroleum Corporation

("Occidental"). Under the terms of the agreement, we are obligated to construct the Century Plant and Occidental is obligated to pay us a minimum of 100% of the contract price, or $800.0 million, plus any subsequently agreed-upon revisions, through periodic cost reimbursements based upon the completion percentage of the project. Contract gains or losses will be recorded as development costs within our oil and natural gas properties as part of the full cost pool, when it is determined that a gain or loss will be incurred. During 2010, we recorded an addition of $105.0 million to our oil and natural gas properties for the estimated loss identified based on current projections of the costs to be incurred in excess of contract amounts.

We expect to complete the Century Plant in two phases. Phase I entered the commissioning stage during the fourth quarter of 2010 and is expected to complete final tests and transfer to Occidental in early 2011. Century Plant Phase II is under construction and expected to come on-line by mid-2012. Upon completion of each phase of the Century Plant, Occidental will take ownership of the related assets and will operate the Century Plant for the purpose of separating and removing CO_2 from delivered natural gas. Pursuant to a 30-year treating agreement executed simultaneously with the construction agreement, Occidental will remove CO_2 from our delivered production volumes. We will retain all methane gas from the natural gas we deliver to the Century Plant.

East Texas — Cotton Valley Trend

We own oil and natural gas interests in the natural gas bearing Cotton Valley Trend, which covers parts of East Texas and Northern Louisiana. As of December 31, 2010, we held interests in 32,650 gross (26,112 net) acres in East Texas. At that time, our estimated net proved reserves in East Texas were 80.1 MMBoe or 480.6 Bcfe, with net production of approximately 5.1 MBoe or 30.3 MMcfe per day for the month of December 2010. We focus our operations in the Cotton Valley Trend on the tight sand reservoirs of the Pettit and Travis Peak formations with depths ranging from 6,500 to 10,500 feet. 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 20 acres per well. We drilled 11 wells in the Cotton Valley Trend in 2010.

Gulf Coast

As of December 31, 2010, we owned oil and natural gas interests in 54,426 gross (27,750 net) acres in the Gulf Coast area, which encompasses the large coastal plain from the southernmost tip of Texas through the southern portion of Louisiana. As of December 31, 2010, our estimated net proved reserves in the Gulf Coast area were 7.8 MMBoe or 46.8 Bcfe, with net production of approximately 3.6 MBoe or 21.6 MMcfe per day for the month of December 2010.

Gulf of Mexico

As of December 31, 2010, we owned oil and natural gas interests in 71,990 gross (39,427 net) acres in state and federal waters off the coasts of Texas and Louisiana. As of December 31, 2010, our estimated net proved reserves in the Gulf of Mexico were 7.5 MMBoe or 45.0 Bcfe, with net production of approximately 1.9 MBoe or 11.4 MMcfe per day for the month of December 2010. Our operations in the Gulf of Mexico extend from the coast to more than 100 miles offshore and occur in waters ranging from 30 feet to 1,100 feet.

Tertiary Oil Recovery

We currently operate one active CO_2 flood and two waterfloods in which CO_2 pilot projects are currently under development. All three floods are located in the Permian Basin area of West Texas. The Wellman Unit, located in Terry County, is an active CO_2 flood in which CO_2 injection was re-initiated in November of 2005. The two prospective CO_2 pilot waterfloods are the George Allen Unit and the South Mallet Unit, located in

Gaines and Hockley Counties. Injection is expected to begin into the George Allen pilot in 2011 and into the South Mallet pilot in 2012.

The three enhanced recovery projects were producing 541 net Boe per day during 2010 and have produced a total of 113.8 MMBoe to date. As of December 31, 2010, net proved reserves attributable to the three properties were 23.4 MMBoe. Expansion opportunities exist in all three projects and will be evaluated based on early performance results.

Proved Reserves

The following historical estimates of net proved oil and natural gas reserves are based on reserve reports as of December 31, 2010, December 31, 2009 and December 31, 2008, substantially all of which were prepared by independent petroleum engineers. The PV-10 and Standardized Measure shown in the table below are not intended to represent the current market value of our estimated oil and natural gas reserves. The reserve reports as of December 31, 2010 and 2009 were based on our drilling schedule and the average price during the 12-month periods ended December 31, 2010 and 2009, using first-day-of-the-month prices for each month. Reserve reports for 2008 were based on oil and natural gas prices at year-end. We estimate that 80% of our current proved undeveloped reserves will be developed by 2013 and all of our current proved undeveloped reserves will be developed by 2014. Refer to "Risk Factors" in Item 1A of this report and "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 of this report in evaluating the material presented below.

SandRidge's Executive Vice President — Reservoir Engineering is the technical person primarily responsible for overseeing the preparation of the Company's reserve estimates. He has a Bachelor of Science degree in Mechanical Engineering with 30 years of practical industry experience, including 25 years of estimating and evaluating reserve information. In addition, our Executive Vice President — Reservoir Engineering has been a certified professional engineer in the state of Oklahoma since 1988 and a member of the Society of Petroleum Engineers since 1980.

SandRidge's Reservoir Engineering Department continually monitors asset performance and makes reserves estimate adjustments, as necessary, to ensure the most current reservoir information is reflected in reserves estimates. Reserve information includes production histories as well as other geologic, economic, ownership and engineering data. The department currently has a total of 18 full-time employees, comprised of seven degreed engineers and 11 engineering analysts/technicians with a minimum of a four-year degree in mathematics, economics, finance or other business or science field.

SandRidge maintains a continuous education program for engineers and technicians on new technologies and industry advancements and also offers refresher training on basic skill sets.

In order to ensure the reliability of reserves estimates, internal controls observed within the reserve estimation process include:

- No employee's compensation is tied to the amount of reserves booked.
- Reserves estimates are made by experienced reservoir engineers or under their direct supervision.
- The Reservoir Engineering Department reports directly to the Company's President, independently from all of our operating divisions.
- The Reservoir Engineering Department follows comprehensive SEC-compliant internal policies to determine and report proved reserves including:
    - confirming that reserve estimates include all properties owned and are based upon proper working and net revenue interests;

- reviewing and using in the estimation process data provided by other departments within the Company such as Accounting; and
- comparing and reconciling internally generated reserve estimates to those prepared by third parties.

Each quarter, the Executive Vice President – Reservoir Engineering presents the status of SandRidge's reserves to the Executive Committee, which subsequently approves all changes. In the event the quarterly updated reserves estimates are disclosed, the aforementioned review process is evidenced by signatures from the Executive Vice President – Reservoir Engineering and the Chief Financial Officer.

SandRidge's Reservoir Engineering Department works closely with its independent petroleum consultants at each fiscal year end to ensure the integrity, accuracy and timeliness of an annually developed independent reserves estimate. These independently developed reserves estimates are adopted as SandRidge's corporate reserves and are reviewed by the Audit Committee, as well as the Chief Financial Officer, Senior Vice President of Accounting, Vice President of Internal Audit, Vice President of Financial Reporting, Treasurer and General Counsel. In addition to reviewing the independently developed reserve reports, the Audit Committee annually interviews the third-party engineer at Netherland Sewell primarily responsible for the reserve report. The Audit Committee also periodically interviews the other independent petroleum consultants used to prepare estimates of proved reserves.

The table below shows the percentage of our total proved reserves for which each of the independent petroleum consultants prepared reports of estimated proved reserves of oil and natural gas for the years shown.

	December 31,		
	2010	**2009**	**2008**
Netherland, Sewell & Associates, Inc.	71.9%	51.7%	90.2%
Lee Keeling and Associates, Inc.	20.3%	33.7%	—
DeGolyer and MacNaughton	4.3%	9.6%	5.4%
Total	96.5%	95.0%	95.6%

The remaining 3.5%, 5.0% and 4.4% of our estimated proved reserves as of December 31, 2010, 2009 and 2008, respectively, were based on internally prepared estimates.

Copies of the reports issued by our independent petroleum consultants are filed with this report as Exhibits 99.1 – 99.3. The geographic location of our estimated proved reserves prepared by each of the independent petroleum consultants as of December 31, 2010 is presented below.

	Geographic Locations - by Area by State
Netherland, Sewell & Associates	Permian Basin - KS, OK, TX
	Mid-Continent - KS, OK
	WTO - TX
	East Texas
	Gulf Coast - LA, TX
	Gulf of Mexico
	Other - AL, MS, ND
Lee Keeling and Associates, Inc.	Permian Basin - NM, TX
DeGolyer and MacNaughton	Tertiary recovery - TX

The qualifications of the technical person at each of these firms primarily responsible for overseeing his firm's preparation of the Company's reserve estimates are set forth below. These qualifications meet or exceed the Society of Petroleum Engineers standard requirements to be a professionally qualified Reserve Estimator and Auditor.

Netherland, Sewell & Associates, Inc.:

- 29 years of practical experience in petroleum engineering and more than 12 years estimating and evaluating reserve information;
- a registered professional engineer in the states of Texas, Louisiana and Wyoming; and
- Bachelor of Science Degree in Civil Engineering and Masters in Business Administration.

Lee Keeling and Associates, Inc.:

- 56 years of practical experience in petroleum engineering and more than 47 years estimating and evaluating reserve information;
- a registered professional engineer in the state of Oklahoma; and
- Bachelor of Science Degree in Petroleum Engineering.

DeGolyer and MacNaughton:

- 35 years of experience in oil and gas reservoir studies and reserves evaluations;
- a registered professional engineer in the state of Texas; and
- Bachelor of Science Degree in Petroleum Engineering.

A summary of our proved oil and natural gas reserves, all of which are located in the continental United States, is presented below:

	December 31,		
	2010	**2009**	**2008**
Estimated Proved Reserves(1)			
Developed			
Oil (MMBbls)	92.0	38.3	15.3
Natural gas (Bcf)(2)	784.3	592.8	851.4
Total proved developed (MMBoe)	222.7	137.1	157.2
Total proved developed (Bcfe)	1,336.2	822.8	943.4
Undeveloped			
Oil (MMBbls)	160.1	67.0	27.8
Natural gas (Bcf)(2)	978.4	87.3	1,048.3
Total proved undeveloped (MMBoe)	323.2	81.6	202.5
Total proved undeveloped (Bcfe)	1,939.1	489.4	1,215.2
Total Proved			
Oil (MMBbls)	252.1	105.3	43.2
Natural gas (Bcf)(2)	1,762.7	680.1	1,899.6
Total proved (MMBoe)	545.9	218.7	359.7
Total proved (Bcfe)	3,275.3	1,312.2	2,158.6
PV-10 (in millions)(3)	$4,509.2	$1,561.0	$2,258.5
Standardized Measure of Discounted Net Cash Flows (in millions)(4)	$3,683.5	$1,561.0	$2,220.6

(1) Our estimated proved reserves and the future net revenues, PV-10 and Standardized Measure were determined using a 12-month average price for oil and natural gas for the years ended December 31, 2010

and 2009 and year-end prices for oil and natural gas as of December 31, 2008. The prices used in our external and internal reserve reports yield weighted average wellhead prices, which are based on index prices and adjusted for transportation and regional price differentials. The index prices and the equivalent weighted average wellhead prices are shown in the table below.

	Weighted average wellhead prices		Index prices	
	Oil (per Bbl)	Natural gas (per Mcf)	Oil (per Bbl)	Natural gas (per Mcf)
December 31, 2010	$66.93	$3.80	$75.96	$4.38
December 31, 2009	$49.98	$3.41	$57.65	$3.87
December 31, 2008	$39.42	$4.94	$41.00	$5.71

(2) Given the nature of our natural gas reserves, our natural gas production, specifically production from the WTO, contains natural gas that is high in CO_2 content. These figures are net of CO_2 volumes that exceed pipeline quality specifications.

(3) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved oil and natural gas 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 for periods prior to December 31, 2009 and 12-month average prices for the years ended December 31, 2010 and 2009. PV-10 differs from Standardized Measure because it does not include the effects of income taxes on future net revenues. Due to the full valuation allowance on our net deferred tax asset at December 31, 2009 that served to reduce to zero a tax benefit that otherwise would result from the tax effects of PV-10, there was no effect of income taxes on Standardized Measure at December 31, 2009. Neither PV-10 nor Standardized Measure represents an estimate of fair market value of our oil and natural gas properties. PV-10 is used by the industry and by our management as an arbitrary reserve asset value measure to compare against past reserve bases and the reserve bases of other business entities that are not dependent on the taxpaying status of the entity. The following table provides a reconciliation of our Standardized Measure to PV-10:

	December 31,		
	2010	2009	2008
		(In millions)	
Standardized Measure of Discounted Net Cash Flows	$3,683.5	$1,561.0	$2,220.6
Present value of future income tax discounted at 10%	825.7	—	37.9
PV-10	$4,509.2	$1,561.0	$2,258.5

(4) Standardized Measure represents the present value of estimated future cash inflows from proved oil and natural gas 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 as Standardized Measure includes the effect of future income taxes. Due to the full valuation allowance on our net deferred tax asset at December 31, 2009 that served to reduce to zero a tax benefit that otherwise would result from the tax effects of PV-10, there was no effect of income taxes on Standardized Measure at December 31, 2009.

Proved oil and natural gas reserves are those quantities of oil and natural gas that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for estimation. To be classified as proved reserves, the project to extract the oil or natural gas must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

The area of a reservoir considered proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establish a lower contact with reasonable certainty.

Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves that can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir, or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. In determining the amount of proved reserves, the price used must be the average price during the 12-month period prior to the ending date of the period covered by the reserve report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved Undeveloped Reserves. During 2010, the Company drilled 424 wells and approximately $480.7 million of our drilling capital expenditures were used to convert approximately 37.4 MMBoe or 224.4 Bcfe of proved undeveloped reserves to proved developed reserves. At December 31, 2010, 392 of these wells were classified as proved developed producing properties with the remaining wells still in progress. During 2009, the Company drilled 104 wells and approximately $128.6 million of our drilling capital expenditures were used to convert approximately 8.7 MMBoe or 52.2 Bcfe of proved undeveloped reserves to proved developed reserves. At December 31, 2009, 92 of these wells were classified as proved developed producing properties with the remaining wells still in progress.

The 12-month average natural gas index price of $4.38 per Mcf, compared to the 12-month average natural gas price of $3.87 for 2009, used in the estimation of natural gas reserves as of December 31, 2010 resulted in upward revisions of quantities associated with the Company's proved undeveloped properties. We recognized additional oil and natural gas reserves attributable to extensions and discoveries as a result of successful drilling in the Permian Basin and Mid-Continent areas. Additionally, the Arena Acquisition resulted in an increase to our proved undeveloped oil and natural gas reserves. The 12-month average natural gas index price of $3.87 per Mcf used in the estimation of reserves as of December 31, 2009 resulted in downward revisions of quantities associated with the Company's proved undeveloped properties as a significant number of properties generated no PV-10 value resulting in the elimination of associated reserve quantities and a shortening of the productive lives of certain proved properties that became uneconomic earlier in their lives with the use of lower natural gas prices compared to prices used in the estimation of reserves in previous periods. There were no downward revisions as a result of the 12-month average oil index price used in the estimation of reserves as of December 31, 2009. For additional information, please see Note 27 to our consolidated financial statements in Item 8 of this report.

Production and Price History

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

	Year Ended December 31,		
	2010	2009	2008
Production Data			
Oil (MBbls)(1)	7,386	2,894	2,334
Natural gas (MMcf)	76,226	87,461	87,402
Total volumes (MBoe)	20,090	17,471	16,901
Total volumes (MMcfe)	120,542	104,823	101,405
Average daily total volumes (MBoe/d)	55.0	47.9	46.2
Average daily total volumes (MMcfe/d)	330.3	287.2	277.1

	Year Ended December 31,		
	2010	2009	2008
Average Prices(2)			
Oil (per Bbl)(1)	$ 66.89	$ 55.62	$ 91.54
Natural gas (per Mcf)	$ 3.68	$ 3.36	$ 7.95
Total (per Boe)	$ 38.56	$ 26.03	$ 53.76
Total (per Mcfe)	$ 6.43	$ 4.34	$ 8.96

(1) Includes natural gas liquids.

(2) Reported prices represent realized average prices for the periods presented and do not give effect to derivative contract settlements.

	Year Ended December 31,		
	2010	2009	2008
Expenses per Boe			
Lease operating expenses:			
Transportation	$ 0.60	$0.66	$0.66
Processing, treating and gathering(1)	1.92	2.17	1.98
Other lease operating expenses	8.54	6.29	6.14
Total lease operating expenses	$11.06	$9.12	$8.78
Production taxes(2)	$ 1.45	$0.23	$1.80
Ad valorem taxes	$ 0.78	$0.60	$0.66
Expenses per Mcfe			
Lease operating expenses:			
Transportation	$ 0.10	$0.11	$0.11
Processing, treating and gathering(1)	0.32	0.36	0.33
Other lease operating expenses	1.42	1.05	1.02
Total lease operating expenses	$ 1.84	$1.52	$1.46
Production taxes(2)	$ 0.24	$0.04	$0.30
Ad valorem taxes	$ 0.13	$0.10	$0.11

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

(2) Net of severance tax refunds.

Productive Wells

The following table sets forth the number of productive wells in which we owned a working interest at December 31, 2010. Productive wells consist of producing wells and wells capable of producing, including oil wells awaiting connection to production facilities and natural gas wells awaiting pipeline connections to commence deliveries. 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.

	Oil		Natural Gas		Total	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Permian Basin	3,099	2,976.2	186	151.9	3,285	3,128.1
Mid-Continent	115	57.3	546	214.1	661	271.4
WTO	20	18.2	882	734.8	902	753.0
East Texas	2	1.7	265	244.0	267	245.7
Gulf Coast	18	9.7	103	64.7	121	74.4
Gulf of Mexico	23	15.4	12	6.6	35	22.0
Tertiary recovery — West Texas	49	46.0	—	—	49	46.0
Other	3	0.7	—	—	3	0.7
Total	3,329	3,125.2	1,994	1,416.1	5,323	4,541.3

The following table presents oil and natural gas production for the years presented for our Fuhrman Mascho field in the Permian Basin and our Piñon field in the WTO, which contained more than 15% of our total proved reserves at year-end.

	2010			
	Oil	**Natural Gas**	**Total**	
Field	**(MMBbls)**	**(MMcf)**	**(MMBoe)**	**MMcfe)**
Fuhrman Mascho field(1)	1,468.4	713.7	1,587.3	9,524.1
Piñon field	60.8	40,314.8	6,779.9	40,679.3

	2009			
	Oil	**Natural Gas**	**Total**	
	(MMBbls)	**(MMcf)**	**(MMBoe)**	**MMcfe)**
Piñon field	108.1	52,228.2	8,812.8	52,876.8

	2008			
	Oil	**Natural Gas**	**Total**	
	(MMBbls)	**(MMcf)**	**(MMBoe)**	**MMcfe)**
Piñon field	108.1	55,356.1	9,334.2	56,005.0

(1) Production is from date property was acquired, or July 16, 2010, through December 31, 2010.

Developed and Undeveloped Acreage

The following table sets forth information regarding our developed and undeveloped acreage at December 31, 2010:

Area	Developed Acreage(1) Gross(3)	Developed Acreage(1) Net(4)	Undeveloped Acreage(2) Gross(3)	Undeveloped Acreage(2) Net(4)
Permian Basin	161,769	134,896	174,865	109,775
Mid-Continent	173,347	93,172	677,707	550,848
WTO	35,933	33,180	589,690	467,886
East Texas	27,944	23,739	4,706	2,373
Gulf Coast	42,763	24,025	11,663	3,725
Gulf of Mexico	66,559	33,996	5,431	5,431
Tertiary recovery — West Texas	8,501	8,056	160	159
Other	820	662	120	21
Total	517,636	351,726	1,464,342	1,140,218

(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 we own a working interest.
(4) The number of net acres is the sum of our 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 is established prior to such date, in which event the lease will remain in effect until production has ceased. The following table sets forth as of December 31, 2010 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, 2011	498,447	392,598
December 31, 2012	328,416	207,189
December 31, 2013	537,866	471,755
December 31, 2014 and later	55,845	38,426
Other(1)	43,768	30,250
Total	1,464,342	1,140,218

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

Drilling Activity

The following table sets forth information with respect to wells we completed during the periods indicated. The information presented is not necessarily indicative of future performance, and should not be interpreted to present any correlation between the number of productive wells drilled and quantities or economic value of reserves found. Productive wells are those that produce commercial quantities of hydrocarbons, regardless of whether they produce a reasonable rate of return. Gross wells refer to the total number of wells in which we had a working interest and net wells refer to gross wells multiplied by our weighted average working interest. As of December 31, 2010, we had 62 gross (58.9 net) wells drilling or awaiting completion.

	2010				2009				2008			
Completed Wells	**Gross**	**Percent**	**Net**	**Percent**	**Gross**	**Percent**	**Net**	**Percent**	**Gross**	**Percent**	**Net**	**Percent**
Development												
Productive	579	95.7%	538.8	95.7%	147	97.4%	117.2	97.9%	398	98.5%	372.4	98.5%
Dry	26	4.3%	24.3	4.3%	4	2.6%	2.5	2.1%	6	1.5%	5.7	1.5%
Total	605	100.0%	563.1	100.0%	151	100.0%	119.7	100.0%	404	100.0%	378.1	100.0%
Exploratory												
Productive	15	83.3%	14.9	83.2%	9	100.0%	8.6	100.0%	48	96.0%	46.4	95.9%
Dry	3	16.7%	3.0	16.8%	—	—	—	—	2	4.0%	2.0	4.1%
Total	18	100.0%	17.9	100.0%	9	100.0%	8.6	100.0%	50	100.0%	48.4	100.0%
Total												
Productive	594	95.3%	553.7	95.3%	156	97.5%	125.8	98.1%	446	98.2%	418.8	98.2%
Dry	29	4.7%	27.3	4.7%	4	2.5%	2.5	1.9%	8	1.8%	7.7	1.8%
	623	100.0%	581.0	100.0%	160	100.0%	128.3	100.0%	454	100.0%	426.5	100.0%

Drilling Rigs

The following table sets forth information with respect to the rigs operating on our acreage as of December 31, 2010.

Area	**Owned**	**Third-Party**
Permian Basin	14	2
Mid-Continent	5	4
WTO	1	—
Total	20	6

Marketing and Customers

We sell oil, natural gas and natural gas liquids to a variety of customers, including utilities, oil and natural gas companies and trading and energy marketing companies. We had two customers that individually accounted for more than 10% of our total revenue during 2010. See Note 25 to our consolidated financial statements in Item 8 of this report for additional information on our major customers. The number of readily available purchasers for our products makes it unlikely that the loss of a single customer in the areas in which we sell our products would materially affect our sales. We are not committed under any existing contracts or agreements to provide fixed and determinable quantities of oil or natural gas in the future.

Title to Properties

As is customary in the oil and natural gas industry, we initially conduct a cursory review of the title to our properties for 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 drilling 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 oil and natural gas leases, we perform title reviews on the most significant leases, and depending on the materiality of properties, we may obtain a drilling title opinion or review previously obtained title opinions. To date, we have obtained drilling title opinions on substantially all of our producing properties and believe that we have good and defensible title to our producing properties. Our oil and natural gas 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

The drilling and related oil field services that we provide to our exploration and production business and to third parties are described below.

Drilling Operations

We drill for our own account primarily in West Texas and Northwest Oklahoma through our drilling and oil field services subsidiary, Lariat. In addition, we also drill wells for other oil and natural gas companies, primarily in the West Texas region. We believe that drilling with our own rigs allows us to control costs and maintain operating flexibility. Our rig fleet is designed to drill in our specific areas of operation and has an average of over 800 horsepower and an average depth capacity of greater than 10,500 feet. As of December 31, 2010, our drilling rig fleet consisted of 31 rigs with 20 of these rigs working on properties that we operated.

The table below presents certain information concerning our contract drilling operations and our rigs:

	Year Ended December 31,		
	2010	2009	2008
Number of operational rigs owned at end of period	31	30	28
Average number of operational rigs owned during the period	27.5	30.0	27.6
Average drilling revenue per day per rig working for third parties(1)(2)	$14,287	$11,398	$14,217

(1) Represents revenues from our rigs working for third parties divided by the total number of days our drilling rigs were used by third parties during the period.

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

The average drilling revenue per day per rig working for third parties increased for the year ended December 31, 2010 compared to 2009 primarily due to some rigs receiving reduced idle or stand-by rates during 2009. There were no rigs receiving idle or stand-by rates during 2010.

As of December 31, 2010, we owned 31 drilling rigs through Lariat. The table below presents a summary of our rigs:

	December 31,		
Rigs	2010	2009	2008
Working for SandRidge	20	14	13
Working for third parties	9	2	3
Idle	2	14	12
Total operational	31	30	28
Non-operational(1)	—	1	3
Total	31	31	31

(1) Includes rigs being serviced at December 31, 2009 and 2008.

Our drilling program and drilling activity for third parties increased significantly in 2010, resulting in more rigs working for us and third parties and fewer rigs idle at December 31, 2010 compared to December 31, 2009 or December 31, 2008.

Types of Drilling Contracts

We obtain our contracts for drilling oil and natural gas wells either through competitive bidding or through direct negotiations with customers. Our drilling contracts generally provide for compensation on a daywork or footage 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, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Segment Overview — Drilling and Oil Field Services Segment" in Item 7 of this report.

Oil Field Services

Our oil field services business conducts operations that together with our drilling services complement our exploration and production business. Oil field services include providing pulling units, trucking, rental tools, location and road construction and roustabout services to us as well as to third parties.

Our Customers

During 2010, we performed approximately 89% of our drilling and oil field services in support of our exploration and production segment and approximately 11% for other operators. For the years ended December 31, 2010, 2009 and 2008, we generated revenues of $28.6 million, $23.6 million and $47.0 million, respectively, for drilling and oil field services performed for third parties.

Capital Expenditures

Our capital expenditures for 2010 related to our drilling and oil field services were $31.7 million. We have budgeted approximately $25.0 million in capital expenditures in 2011 for our drilling and oil field services segment.

Midstream Gas Services

We provide gathering, compression and treating services of natural gas in West Texas. Our midstream operations and assets not only serve our exploration and production segment, but also service other oil and natural gas companies. The following tables set forth information regarding our primary midstream assets as of December 31, 2010:

Gas Treating Plants (West Texas)	Plant Capacity (MMcf/d)	Average Utilization(1)	Third-Party Usage
Pike's Peak	90	85%	<1%
Grey Ranch	220	70%	8%

(1) Average utilization for the year ended December 31, 2010.

SandRidge CO_2 Compression Facilities (West Texas)	CO_2 Compression Capacity (MMcf/d)	Average Utilization (1)
Pike's Peak	36.0	89%
Mitchell	26.5	69%
Grey Ranch	88.0	72%
Terrell	28.0	84%

(1) Average utilization for the year ended December 31, 2010.

West Texas

In Pecos County, we own and operate the Pike's Peak gas treating plant, which has the capacity to treat 90 MMcf per day of natural 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 2020. In October 2009, we took over operations at the Grey Ranch plant pursuant to an agreement with such partnership. The treating capacities for both the Pike's Peak and Grey Ranch plants are dependent upon the quality of natural gas being treated. The data included in the table above for the Pike's Peak and Grey Ranch plants is based on a natural gas stream that averaged 66% CO_2.

Our two West Texas gas treating 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. In addition, we have access for up to 60 MMcf per day of treating capacity at Hoover Energy Partners' Mitchell Plant under a long-term fixed fee arrangement.

We also own or operate over 1,100 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 oil and natural gas 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, 2010, we owned or operated approximately 86,000 horsepower of gas compression in West Texas.

In conjunction with the June 2009 sale of our gathering and compression assets located in the Piñon Field, we entered into a gas gathering agreement and an operations and maintenance agreement. Under the gas gathering agreement, we have dedicated the Piñon Field acreage for priority gathering services for a period of 20 years and we will pay a fee that was negotiated at arms' length for such services.

Other Areas

As of December 31, 2010, we owned approximately 82 miles of pipeline gathering systems and operated more than 13,000 horsepower of natural gas compression in East Texas. We also owned approximately 83 miles of pipeline gathering systems and operated over 4,000 horsepower of gas compression in the Gulf Coast area, and owned approximately 47 miles of pipeline in the Mid-Continent area.

Capital Expenditures

The growth of our midstream assets is driven by our oil and natural gas 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 2010, we spent $48.4 million in capital expenditures primarily to install pipeline and compression infrastructure. With Phase I of the Century Plant expected to be fully commissioned in early 2011, we will add 400 MMcf per day in available treating capacity in 2011. We have budgeted approximately $105.0 million in 2011 capital expenditures for our midstream gas services segment and other general corporate purposes.

Marketing

Through Integra Energy, L.L.C., our wholly owned subsidiary, we buy and sell natural gas from wells we operate and wells operated by third parties within our West Texas operations. 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 published pricing indices to eliminate price exposure.

We periodically buy and sell third-party natural gas. 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 50,000 MMBtu per day of firm transportation service subscribed on the Oasis Pipeline and 75,000 MMBtu per day on the Mid-Continent Express Pipeline for a portion of our Piñon Field production for 2011.

Other Operations

Our CO_2 capturing operations are conducted through SandRidge CO_2. As of December 31, 2010, SandRidge CO_2 owned 245 miles of CO_2 pipelines in West Texas with approximately 63,000 horsepower of owned and leased CO_2 compression available and currently operational. The captured CO_2 is primarily used for tertiary oil recovery operations. As of December 31, 2010, SandRidge CO_2 was capturing approximately 134 MMcf per day of CO_2. We delivered the majority of this to Occidental Permian Ltd. In December 2010, we captured and sold an average of 132 MMcf of CO_2 per day and utilized 30 MMcf per day in our enhanced oil recovery projects.

Future regulation of greenhouse gas emissions may provide us 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. 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 2.8 million metric tonnes of CO_2 per year, all of which is utilized in enhanced oil recovery projects. The captured CO_2 may prove beneficial to us if the CO_2 capture results in ERCs that can be traded or used by us to meet future regulatory compliance obligations that may otherwise be costly to satisfy. ERCs of just over 0.2 million metric tonnes were sold on the voluntary market during 2010. See "— Environmental Regulations."

Competition

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

We believe our geographic concentration of operations and vertical integration enables us to compete effectively with other exploration and production operations. We compete with major oil and natural gas companies and independent oil and natural gas companies for leases, equipment, personnel and markets for the sale of oil and natural gas. Many of these competitors are financially stronger than us, but even financially troubled competitors can affect the market because of their need to sell oil and natural gas at any price to attempt to maintain cash flow. Certain 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 oil and natural gas market prices. Our larger or fully 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 depends on 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 oil and natural gas properties.

Oil and natural gas compete with other forms of energy available to customers, primarily based on price. These alternate forms of energy include electricity, coal and fuel oils. Changes in the availability or price of oil and natural gas or other forms of energy, as well as business conditions, conservation, legislation, regulations and the ability to convert to alternate fuels and other forms of energy may affect the demand for oil and natural gas.

With respect to our drilling business, we believe the type, age and condition of our drilling rigs, the quality of our crews 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 usually awarded on the basis of competitive bids. We may, based on the economic environment at the time, determine that market conditions and profit margins are such that contract drilling for third parties is not a beneficial use of our resources.

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 and the experience of our rig crews 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. 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 natural 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.

Seasonal Nature of Business

Generally, demand for oil and natural gas decreases during the summer months and increases during the winter months. 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 oil and natural gas 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 Regulations

General

The exploration, development and production operations of oil and natural gas are subject to federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may, among other things, require permits to conduct drilling, water withdrawal and waste disposal operations; govern the amounts and types of substances that may be disposed or released into the environment; limit or prohibit construction or drilling activities in sensitive areas such as wetlands, wilderness areas or areas inhabited by endangered or threatened species; require investigatory and remedial actions to mitigate pollution conditions arising from our operations or attributable to former operations; and impose obligations to reclaim and abandon well sites and pits. Failure to comply with these laws and regulations may result in the assessment of sanctions, including monetary penalties, the imposition of remedial obligations and the issuance of orders enjoining some or all of our operations in affected areas.

The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly waste handling, storage, transport, disposal, or remediation requirements could have a material adverse effect on our operations and financial position. We may be unable to pass on such increased compliance costs to its customers. Moreover, accidental releases or spills may occur in the course of our operations, and there can be no assurance that we will not incur significant costs and liabilities as a result of such releases or spills, including any third party claims for damage to property and natural resources or personal injury.

The following is a summary of the more significant existing environmental, health and safety laws and regulations applicable to the oil and natural gas industry and for which compliance may have a material adverse impact on our operations.

Hazardous Substances and Wastes

The Comprehensive Environmental Response, Compensation, and Liability Act, as amended ("CERCLA"), also known as the Superfund law and comparable state laws impose joint and several liability without regard to fault or legality of conduct, on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include current and prior owners or operators of the site where the release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these "responsible persons" may be subject to strict joint and several, liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain environmental and health studies. In addition, it is not uncommon for neighboring land owners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances into the environment. CERCLA also authorizes the Environmental Protection Agency ("EPA") and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. We generate materials in the course of our operations that may be regulated as hazardous substances.

We also generate wastes that are subject to the requirements of the Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable state statutes. RCRA imposes strict requirements on the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. In the course of our operations, we generate petroleum hydrocarbon wastes and ordinary industrial wastes that are subject to regulation under the RCRA. We are in substantial compliance with all regulations regarding the handling and disposal of oil and natural gas exploration and production wastes from its operations.

We currently own or lease, and in the past may have owned or leased, properties that have been used to explore for and produce oil and natural gas. Although we may have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons and wastes may have been disposed of or released on or under the properties owned or leased by us or on or under the other locations where these hydrocarbons and wastes have been taken for treatment or disposal. In addition, certain of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons and wastes was not under our control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes, to clean up contaminated property and to perform remedial operations to prevent future contamination.

Air Emissions

The federal Clean Air Act and comparable state laws control emissions of potentially harmful air emissions through permitting and monitoring regulations. We are required to obtain various permits to ensure that emissions from our operations remain within permitted levels. To comply with the terms of these permits, and, as part of our ongoing efforts to operate in an environmentally responsible manner, we have installed and maintained emission control technologies throughout our systems.

Climate Change

In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and certain other greenhouse gases ("GHGs") present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. These findings allow the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. Accordingly, the EPA has proposed regulations that would require a reduction in emissions of GHGs from motor vehicles and adopted regulations that could trigger permit review for GHG emissions from certain stationary sources. In addition, in October 2009, the EPA published a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, including sources emitting more than 25,000 tons of GHGs on an annual basis, beginning in 2011 for emissions occurring in 2010. On November 30, 2010, the EPA published a final rule that expands its October 2009 final rule on reporting of GHG emissions to include owners and operators of onshore and offshore oil and natural gas production, effective December 30, 2010. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHG gases from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with its operations or could adversely affect demand for the oil and natural gas it produces. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our assets and operations.

In addition, Congress has actively considered legislation to reduce emissions of GHGs and President Obama has indicated his support of legislation to reduce GHG emission through an emission allowance system. Even if such legislation is not adopted at the national level, almost one-half of the states have begun taking actions to control and/or reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Although most of the state-level initiatives have to date focused on large sources of GHG emissions, such as coal-fired electric plants, it is possible that smaller sources of emissions could become subject to GHG emission limitations or allowance purchase requirements in the future. Any future federal laws or implementing regulations that may be adopted to address GHG emissions could require us to incur increased operating costs, could adversely affect demand for the oil and natural gas that we produce, and could have a material adverse effect on our business, financial condition and results of operations. We will formally assess GHG emissions related to all company operations in 2011. We do not believe the total cost of this project will be material.

Water Discharge

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 natural gas and oil 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 ("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 requirements 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, conduct annual spill drills and provide varying degrees of financial assurance.

Groundwater and Safe Drinking Water Act

Oil and natural gas may be recovered from certain of our oil and natural gas properties through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Hydraulic fracturing, which involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production, is typically regulated by state oil and gas commissions but is not subject to regulation at the federal level. The EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with results of the study anticipated to be available by late 2012, and a committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. Legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states have adopted regulations that could restrict hydraulic fracturing in certain circumstances. If new laws or regulations that significantly restrict hydraulic fracturing are adopted in the states in which we operate, such legal requirements could make it more difficult or costly for us to perform fracturing to stimulate production in the Mississippian play and thereby affect the determination of whether a well is commercially viable. In addition, if hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permit requirements or operational restrictions and also to associated permitting delays and potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce in commercial quantities.

National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands or otherwise requiring federal approval are subject to the National Environmental Policy Act ("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 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 oil and natural gas projects in covered areas.

Endangered Species Act

The federal Endangered Species Act, as amended ("ESA"), restricts activities that may affect endangered and threatened species or their habitats. While some of our facilities or leased acreage may be located in areas that are designated as habitat for endangered or threatened species, we believes that we are in substantial compliance with the ESA. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Employee Health and Safety

Our operations are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, as amended ("OSHA"), and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

State Regulation

The states in which we operate regulate the drilling for, and the production and gathering of, oil and natural gas, including requirements relating to drilling permits, the location, spacing and density of wells, unitization and pooling of interests, the method of drilling, casing and equipping of wells, the protection of fresh water sources, the orderly development of common sources of supply of oil and natural gas, the operation of wells, allowable rates of production, the use of fresh water in oil and natural gas operations, saltwater injection and disposal operations, the plugging and abandonment of wells and the restoration of surface properties, the prevention of waste of oil and natural gas resources, the protection of the correlative rights of oil and natural gas owners and, where necessary to avoid unfair, unjust or discriminatory service, the fees, terms and conditions for the gathering of natural gas. The effect of these regulations may be to limit the number of wells that we may drill, impact the locations at which we may drill wells, restrict the amounts of oil and natural gas that may be produced from our wells and increase the costs of our operations.

Anti-Terrorism Measures

The federal Department of Homeland Security Appropriations Act of 2007 requires the Department of Homeland Security ("DHS") to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and natural gas facilities that are deemed to present high levels of security risk. The DHS issued an interim final rule in 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 establishing chemicals of interest and their respective threshold quantities that will trigger compliance with the interim rules. We have performed a preliminary assessment of our major facilities and determined that one of our facilities may require a formal vulnerability assessment and security plan. The costs to implement additional security measures as a result could be substantial.

Other Regulation of the Oil and Natural Gas Industry

The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities, including Native American tribes. Legislation affecting the oil and natural gas 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 oil and natural gas industry and its individual members, some of which carry substantial penalties for noncompliance. Although the regulatory burden on the oil and natural gas 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.

The availability, terms and cost of transportation significantly affect sales of oil and natural gas. The interstate transportation and sale for resale of oil and natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission. Federal and state regulations govern the price and terms for access to oil and natural gas pipeline transportation. The Federal Energy Regulatory Commission's regulations for interstate oil and natural gas transmission in some circumstances may also affect the intrastate transportation of oil and natural gas.

Although oil and natural gas prices are currently unregulated, Congress historically has been active in the area of oil and natural gas regulation. We cannot predict whether new legislation to regulate oil and natural gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on our operations. Sales of condensate and oil and natural gas liquids are not currently regulated and are made at market prices.

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 tribal areas where we operate also regulate one or more of the following activities:

- the location of wells;
- the method of drilling and casing wells;
- the timing of construction or drilling activities;
- the rates of production or "allowables";
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- the 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 oil and natural gas 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 oil and natural gas 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 oil and natural gas 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 natural gas, oil 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. Regulations of the Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMR") 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. BOEMR requires federal leaseholders to post performance bonds or otherwise provide necessary financial assurances to provide for such abandonment, decommissioning and removal. The New Mexico Oil Conservation requires the posting of performance bonds to fulfill financial requirements for owners and operators on state land. The Railroad Commission of Texas has financial responsibility requirements for owners and operators of facilities in state waters to provide for similar assurances. The United States Army Corps of Engineers ("ACOE") and many other state and local authorities also have regulations for plugging and abandonment, decommissioning and site restoration. Although the ACOE does not require bonds or other financial assurances, some state agencies and municipalities do have such requirements.

Natural Gas Sales and 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 ("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. Various federal laws enacted since 1978 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. Under the Energy Policy Act of 2005, FERC has substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties.

FERC also regulates interstate natural gas transportation rates and service conditions and establishes the terms under which we may use interstate natural gas pipeline capacity, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas and release of our natural gas pipeline capacity. 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, open access market for natural gas purchases and sales that permits all purchasers of natural 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 has in the past reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of transporting gas to point-of-sale locations.

Employees

As of December 31, 2010, we had 2,192 full-time employees, including more than 282 geologists, geophysicists, petroleum engineers, technicians, land and regulatory professionals. Of our 2,192 employees, 573 are located at our headquarters in Oklahoma City, Oklahoma, and the remaining employees work in our various field offices and at our drilling sites.

Glossary of Oil and Natural Gas Terms

The following is a description of the meanings of some of the oil and natural gas industry terms used in this report.

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 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 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. Although an equivalent barrel of condensate or natural gas may be equivalent to a barrel of oil on an energy basis, it is not equivalent on a value basis as there may be a large difference in value between an equivalent barrel and a barrel of oil. For example, based on the commodity prices used to prepare the estimate of our reserves at year-end 2010 of $4.38/Mcf for natural gas and $75.96/Bbl for oil, the ratio of economic value of oil to gas was approximately 17 to 1, even though the ratio for determining energy equivalency is 6 to 1.

Boe/d. Boe per day.

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 oil or natural gas, or in the case of a dry well, the reporting to the appropriate authority that the well has been abandoned.

Condensate. A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

CO_2. Carbon dioxide.

Developed acreage. The number of acres that are assignable to productive wells.

Developed oil and natural gas reserves. Developed oil and natural gas reserves are reserves of any category that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Development costs. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and natural gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to (i) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building and relocating public roads, gas lines and power lines, to the extent necessary in developing the proved reserves, (ii) drill and equip development wells, development-type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly, (iii) acquire, construct and install, production facilities such as leases, flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems, and (iv) provide improved recovery systems.

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

Dry well. An exploratory, development or extension well that proves to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

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 oil and natural gas 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 oil and natural gas 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 a new field or to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geological barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas of interest, etc.

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 oil or other liquid hydrocarbons.

MBoe. Thousand barrels of oil equivalent.

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 oil, condensate or natural gas liquids.

MMBbls. Million barrels of 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 oil, condensate or natural gas liquids. Although an equivalent barrel of condensate or natural gas may be equivalent to a barrel of oil on an energy basis, it is not equivalent on a value basis as there may be a large difference in value between an equivalent barrel and a barrel of oil. For example, based on the commodity prices used to prepare the estimate of our reserves at year-end 2010 of $4.38/Mcf for natural gas and $75.96/Bbl for oil, the ratio of economic value of oil to gas was approximately 17 to 1, even though the ratio for determining energy equivalency is 6 to 1.

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%.

Production costs.

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.

(B) Repairs and maintenance.

(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.

(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

Productive well. A well that is found to be capable of producing oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

Prospect. A specific geographic area that, 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. Reserves that are both proved and developed.

Proved oil and natural gas reserves. Has the meaning given to such term in Rule 4-10(a)(22) of Regulation S-X, which defines proved reserves as:

Those quantities of oil and natural gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

The area of a reservoir considered proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establish a lower contact with reasonable certainty.

Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir, or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved undeveloped reserves. Reserves that are both proved and undeveloped.

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

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

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.

Reserves. Estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to market, and all permits and financing required to implement the project.

Included Note: Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e. absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e. potentially recoverable resources from undiscovered accumulations).

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and 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 oil and natural gas 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 on future net revenues.

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

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

Undeveloped oil and natural gas reserves. Reserves of any category 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.

(i) Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations are classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves 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 projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology establishing reasonable certainty.

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.

Item 1A. *Risk Factors*

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

Our revenues, profitability and cash flow depend upon the prices and demand for oil and natural gas. The markets for these commodities are very volatile. Oil and natural gas prices can fluctuate widely in response to a variety of factors that are beyond our control. These factors include, among others:

- regional, domestic and foreign supply, and perceptions of supply, of oil and natural gas;
- the price of foreign imports;
- U.S. and worldwide political and economic conditions;
- the level of demand, and perceptions of demand, for oil and natural gas;
- weather conditions and seasonal trends;
- anticipated future prices of oil and natural gas, alternative fuels and other commodities;
- technological advances affecting energy consumption and energy supply;
- the proximity, capacity, cost and availability of pipeline infrastructure, treating, transportation and refining capacity;
- acts of force majeure;
- domestic and foreign governmental regulations and taxation;
- energy conservation and environmental measures; and
- the price and availability of alternative fuels.

For oil, from 2007 through 2010, the highest monthly NYMEX settled price was $134.62 per Bbl and the lowest was $33.87 per Bbl. For natural gas, from 2007 through 2010, the highest monthly NYMEX settled price was $13.11 per MMBtu and the lowest was $2.84 per MMBtu. In addition, the market price of oil and natural gas is generally higher in the winter months than during other months of the year due to increased demand for oil and natural gas for heating purposes during the winter season.

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

Future price declines may result in further reductions of the asset carrying values of our oil and natural gas properties.

We utilize the full cost method of accounting for costs related to our oil and natural gas properties. Under this accounting method, all costs for both productive and nonproductive properties are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the unit-of-production method. However, the amount of these costs that can be carried as capitalized assets is subject to a ceiling, which limits such pooled costs to the aggregate of the present value of future net revenues of proved oil and natural gas reserves attributable to proved properties, discounted at 10%, plus the lower of cost or market value of unevaluated properties. The full cost ceiling is evaluated at the end of each quarter using the most recent 12-month average prices for oil and natural gas, adjusted for the impact of derivatives accounted for as cash flow hedges. In the event any of our derivatives are accounted for as cash flow hedges, the impact of these derivative contracts will be included in the determination of our full cost ceiling. We had no full cost ceiling impairments during the year ended December 31, 2010, while our ceiling limitations during 2009 resulted in non-cash impairment charges totaling $1,693.3 million. Future declines in oil and natural gas prices, without other mitigating circumstances, could result in additional losses of future net revenues, including losses attributable to quantities that cannot be economically produced at lower prices, which could cause us to make additional write-downs of capitalized costs of our oil and natural gas properties and non-cash charges against future earnings. The amount of such future write-downs and non-cash charges could be substantial.

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

As of December 31, 2010, our total indebtedness was $2.9 billion, and we had preferred stock outstanding with an aggregate liquidation preference of $765.0 million. Our substantial level of indebtedness and the dividends payable on our preferred stock outstanding 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 and/or the preferred stock dividends. Our indebtedness and outstanding preferred stock, 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 disadvantage compared to our competitors that are less leveraged and, therefore, may be able to take advantage of opportunities that our indebtedness 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 have a material adverse effect on our business, financial condition and results of operations.

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 could materially affect the quantities and present value of our reserves. Our current estimates of reserves could change, potentially in material amounts, in the future.

The process of estimating oil and natural gas 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 oil and natural gas 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 — Our Businesses and Primary Operations" in Item 1 of this report for information about our oil and natural gas reserves.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas 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, which in turn could have a negative effect on the value of our assets. In addition, from time to time in the future, we may adjust estimates of proved reserves, potentially in material amounts, to reflect production history, results of exploration and development, oil and natural gas 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 oil and natural gas reserves.

We base the estimated discounted future net cash flows from our proved reserves on 12-month average prices and costs. Actual future net cash flows from our oil and natural gas properties also will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- the accuracy of our reserve estimates;
- the actual cost of development and production expenditures;
- the amount and timing of actual production;
- supply of and demand for oil and natural gas; 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 oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, we use a 10% discount factor when calculating discounted future net cash flows which 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 oil and natural gas industry in general.

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

Our future oil and natural gas 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.

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

The use of seismic data and other technologies and the study of producing fields in the same area does 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 2010, we participated in drilling a total of 623 gross wells, of which 29 were identified as dry wells. If we drill additional wells that we identify as dry wells in our current and future prospects, our drilling success rate may decline and materially harm our business. In summary, the cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive.

Volatility in the capital markets could affect our ability to obtain capital, cause us to incur additional financing expense or affect the value of certain assets.

In recent periods, global financial markets and economic conditions have been disrupted and volatile due to multiple factors, including significant write-offs in the financial services sector and weak economic conditions. In some cases, the markets have produced downward pressure on stock prices and credit capacity for certain issuers without regard to those issuers' underlying financial and/or operating strength. Due to this volatility, for many companies the cost of raising money in the debt and equity capital markets has been greater in recent periods than has historically been the case. Continued market volatility may from time to time adversely affect our ability to access capital and credit markets or to obtain funds at low interest rates or on other advantageous terms. These factors may adversely affect our business, results of operations or liquidity.

These factors may adversely affect the value of certain of our assets and our ability to draw on our senior credit facility. Adverse credit and capital market conditions may require us to impair the carrying value of assets associated with derivative contracts to account for non-performance by counterparties to those contracts. If financial institutions that have extended credit commitments to us are adversely affected by volatile conditions of the United States and international capital markets, they may become unable to fund borrowings under their credit commitments to us, which could have a material adverse effect on our financial condition and our ability to borrow additional funds, if needed, for working capital, capital expenditures and other corporate purposes.

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 an in-depth review of every individual property involved in each acquisition generally is not feasible. 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 may assume certain environmental and other risks and liabilities in connection with acquired properties, and such risks and liabilities could have a material adverse effect on our results of operations and financial condition.

The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate.

As of December 31, 2010, 59.2% of our total reserves were 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 West Texas, Northwest Oklahoma and Kansas, making us vulnerable to risks associated with operating in a limited number of major geographic areas.

As of December 31, 2010, approximately 78.2% of our proved reserves and approximately 77.6% of our annual production were located in the Permian Basin, Mid-Continent and WTO. This concentration could disproportionately expose us to operational and regulatory risk in these areas. This relative lack of diversification in location of our key operations could expose us to adverse developments in these areas or the oil and natural gas markets, including, for example, transportation or treatment capacity constraints, curtailment of production or treatment plant closures for scheduled maintenance. These factors could have a significantly greater impact on our financial condition, results of operations and cash flows than if our properties were more diversified.

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 oil and natural gas reserves.

The oil and natural gas industry is capital intensive. We make substantial capital expenditures in our business and operations for the exploration, development, production and acquisition of oil and natural gas reserves. Historically, we have financed capital expenditures primarily with proceeds from asset sales and from the sale of equity, debt and cash generated by operations. We will finance our future capital expenditures with the sale of equity and debt securities, cash flow from operations, asset sales 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 oil and natural gas we are able to produce from existing wells;
- the prices at which oil and natural gas are sold; and
- our ability to acquire, locate and produce new reserves.

If our revenues decrease as a result of lower oil and natural gas 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 may seek additional financing. However, our senior credit facility contains covenants limiting our ability to incur additional indebtedness, which our lenders may withhold in their sole discretion. Our senior note indentures also contain covenants that may restrict our ability to incur additional indebtedness if we do not satisfy certain financial metrics. If we are unable to obtain additional financing, it may be necessary for us to reduce or suspend our capital expenditures.

Continuing disruptions in the global financial and capital markets also could adversely affect our ability to obtain debt or equity financing on favorable terms, 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 oil and natural gas reserves.

The agreements governing our existing indebtedness have restrictions, financial covenants and borrowing base redeterminations which could adversely affect our operations.

Our senior credit facility and the indentures governing our senior notes 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. If commodity prices decline, this could adversely affect our ability to meet such restrictions and covenants. Our failure to comply with any of the restrictions and covenants under the senior credit facility, senior notes or other debt financing could result in a default under those instruments, which could cause all of our existing indebtedness to be immediately due and payable.

Our senior credit facility limits the amounts we can borrow to a borrowing base amount. The borrowing base is subject to review semi-annually; however, the lenders reserve the right to have one additional re-determination of the borrowing base per calendar year. Unscheduled re-determinations may be made at our request, but are limited to two requests per year. Borrowing base determinations are based upon proved developed producing reserves, proved developed non-producing reserves and proved undeveloped reserves. Outstanding borrowings exceeding the borrowing base must be repaid immediately, or we must pledge other oil and natural gas properties as additional collateral. Because of this, we may not have the financial resources in the future to make any mandatory principal prepayments under the senior credit facility, which are required, for example, when the committed line of credit is exceeded, proceeds of asset sales in new oil and natural gas properties are not reinvested, or indebtedness that is not permitted by the terms of the senior credit facility is incurred. If the indebtedness under our senior credit facility and senior notes were to be accelerated, our assets may not be sufficient to repay such indebtedness in full.

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

To achieve a more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we currently have, and may in the future, enter into derivative contracts for a portion of our oil and natural gas production, including collars, basis swaps and fixed-price swaps. As of December 31, 2010, we had oil price swaps of 8,288 MBbls at an average price of $86.08 per MBbl for 2011, 9,547 MBbls at an average price of $87.10 per MBbl for 2012 and 5,384 MBbls at an average price of $88.77 per MBbl for 2013. We also had natural gas price swaps of 59.6 Bcf at an average price of $4.69 per Mcf in place for 2011 and 26.8 Bcf at an average price of $5.15 per Mcf for 2012. The Company also has natural gas basis swaps in place through 2013 for 232.1 Bcf at an average price of $0.51 per Mcf and natural gas collars in place through 2015 for 3.2 Bcf with an average floor price of $4.00 and an average ceiling price of $7.66. We have not and do not plan to designate any of our derivative contracts as hedges for accounting purposes and, as a result, record all derivative contracts on our balance sheet at fair value. Changes in the fair value of our derivative contracts are recognized in current period earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative contracts. Derivative contracts also expose us to the risk of financial loss in some circumstances, including when:

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

In addition, these types of derivative contracts limit the benefit we would receive from increases in the prices for oil and natural gas.

All of our consolidated drilling and services revenues are derived from companies in the oil and natural gas industry.

Companies to which we provide drilling and related services are affected by the oil and natural gas industry risks mentioned above. Market prices of oil and natural gas, limited access to capital and reductions in capital expenditures could result in oil and natural gas companies canceling or curtailing their drilling programs, which could reduce the demand for our drilling and related services. Any prolonged reduction in the overall level of exploration and development activities, whether resulting from changes in oil and natural gas prices or otherwise, could impact our drilling and services segment by negatively affecting:

- revenues, cash flow and profitability;
- our ability to retain skilled rig personnel whom we would need in the event of an upturn in the demand for drilling and related services; and
- the fair value of our rig fleet.

A significant decrease in natural gas production in our areas of operations, due to declines in production from existing wells, depressed commodity prices or otherwise, would adversely affect our ability to satisfy certain contractual obligations and revenues and cash flow from our midstream gas services segment.

In June 2009, we sold an entity, Piñon Gathering Company, LLC ("PGC"), holding our gathering and compression assets located in the Piñon Field, which is part of the WTO in Pecos County, Texas, to an unaffiliated third party. In conjunction with the sale, we entered into a gas gathering agreement pursuant to which we dedicated our Piñon Field acreage to PGC for gathering services for 20 years. During that period, we have minimum throughput and delivery obligations to PGC. In addition, we continue to construct gathering and compression assets in the Piñon Field. Most of the reserves supporting our contractual obligations to PGC and our own 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

PGC and our pipelines and facilities for gathering, transporting and treating. 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. We are obligated to pay minimum fees under the gas gathering agreement with PGC if we do not satisfy the contractual throughput and delivery commitments to PGC, due, for example, to our failure to connect new wells to PGC's gathering systems or when there is a decline in the amount of natural gas that we produce from the Piñon Field. In addition, if we fail to connect new wells to our own gathering systems, the amount of natural gas we gather, transport and treat will decline substantially over time and could, upon exhaustion of the current wells, cause us to abandon our gathering systems and, possibly cease gathering, transporting and treating operations.

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

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

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. After giving effect to plant shrink, as many as 3.5 Mcf of high CO_2 natural 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.

Our use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas. In addition, the use of such technology requires greater predrilling expenditures, 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 may 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, we will have 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 oil and natural gas 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 oil and natural gas can be unprofitable if dry wells are drilled and if productive wells 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:

- delays imposed by or resulting from compliance with regulatory requirements including permitting;
- unusual or unexpected geological formations and miscalculations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment malfunctions, failures or accidents;
- lack of available gathering facilities or delays in construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines;
- unexpected operational events and drilling conditions;
- pipe or cement failures;
- casing collapses;
- pressures, fires and blowouts;
- lost or damaged drilling and service tools;
- loss of drilling fluid circulation;
- uncontrollable flows of oil and natural gas, water or drilling fluids;
- natural disasters;
- environmental hazards, such as oil and natural gas leaks, pipeline ruptures and discharges of toxic gases;
- adverse weather conditions and natural disasters;
- reductions in oil and natural gas prices;
- oil and natural gas property title problems; and
- market limitations for oil and natural gas.

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 could incur losses for uninsurable or uninsured risks or in amounts exceeding 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.

The high cost or unavailability of drilling rigs, equipment, supplies, personnel and other oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies or qualified personnel. During these periods, the costs of rigs, equipment, supplies and personnel are substantially greater and their availability may be limited. Additionally, these services may not be available on commercially reasonable terms.

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

Market conditions or a lack of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas 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 treating facilities. For example, in 2009 we experienced capacity limitations on high CO_2 gas treating in the Piñon Field. Our failure to obtain such services on acceptable terms in the future or expand our midstream assets could have a material adverse effect on 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 treating facilities may be limited or unavailable. We would be unable to realize revenue from any shut-in wells until production arrangements were made to deliver the production to market.

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

The oil and natural gas industry is intensely competitive, and we compete with companies that have greater resources than we do. Many of these companies not only explore for and produce oil and natural gas, 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 oil and natural gas 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 oil and natural gas 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 oil and natural gas properties. See "Business — Competition" in Item 1 of this report.

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

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

Our oil and natural gas 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. Further, in light of the explosion and fire on the drilling rig Deepwater Horizon in the Gulf of Mexico, as well as incidents involving the release of oil and natural gas and fluids as a result of drilling activities in the United States, there has been a variety of regulatory initiatives at the federal and state level to restrict oil and natural gas drilling operations in certain locations. Any increased regulation or suspension of oil and natural gas exploration and production, or revision or reinterpretation of existing laws and regulations, that arises out of these incidents or otherwise could result in delays and higher operating costs. Such costs or significant delays could have a material adverse effect on our business, financial condition and results of operations. We must also comply with laws and regulations prohibiting fraud and market manipulations in energy markets. To the extent we are a shipper on interstate pipelines, we must comply with tariffs of such pipelines and with federal policies related to the use of interstate capacity.

Laws and regulations governing oil and natural gas exploration and production may also affect production levels. We are required to comply with federal and state laws and regulations governing conservation matters, including provisions related to the unitization or pooling of the oil and natural gas properties; the establishment of maximum rates of production from wells; the spacing of wells; and the plugging and abandonment of wells. These and other laws and regulations can limit the amount of oil and natural gas we can produce from our wells, limit the number of wells we can drill, or limit the locations at which we can conduct drilling operations.

New laws or regulations, or changes to existing laws or regulations may unfavorably impact us, could result in increased operating costs and have a material adverse effect on our financial condition and results of operations. For example, Congress is currently considering legislation that, if adopted in its proposed form, would subject companies involved in oil and natural gas and oil exploration and production activities to, among other items, additional regulation of and restrictions on hydraulic fracturing of wells, the elimination of most U.S. federal tax incentives and deductions available to oil and natural gas exploration and production activities, and the prohibition or additional regulation of private energy commodity derivative and hedging activities.

Additionally, state and federal regulatory authorities may expand or alter applicable pipeline safety laws and regulations, compliance with which may require increased capital costs on the part of us and third party downstream oil and natural gas transporters. These and other potential regulations could increase our operating costs, reduce our liquidity, delay our operations, increase direct and third party post production costs or otherwise alter the way we conducts our business, which could have a material adverse effect on our financial condition, results of operations and cash flows and which could reduce cash received by or available for distribution, including any amounts paid by us for transportation on downstream interstate pipelines.

Our operations are subject to environmental laws and regulations that may result in significant costs and liabilities.

Our oil and natural gas exploration and production operations are subject to stringent and comprehensive federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations that are applicable to our operations including the acquisition of a permit before conducting drilling; water withdrawal or waste disposal activities; the restriction of types, quantities and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and the imposition of substantial liabilities for pollution resulting from operations. Numerous governmental authorities, such as the U.S. Environmental Protection Agency ("EPA") and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties; the imposition of investigatory or remedial obligations; and the issuance of injunctions limiting or preventing some or all of our operations.

There is inherent risk of incurring significant environmental costs and liabilities in the performance of our operations due to its handling of petroleum hydrocarbons and wastes, because of air emissions and wastewater discharges related to its operations, and as a result of historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we could be subject to joint and several strict liability for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or contamination or if the operations were not in compliance with all applicable laws at the time those actions were taken. Private parties, including the owners of properties upon which our wells are drilled and facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal may also have the right to pursue legal actions to enforce compliance, as well as to seek damages for non-compliance, with environmental laws and regulations or for personal injury or property damage. In addition, the risk of accidental spills or releases could expose us to significant liabilities that could have a material adverse effect on our financial condition or results of operations. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on its results of operations, competitive position or financial condition. We may not be able to recover some or any of these costs from insurance. As a result of the increased cost of compliance, we may decide to discontinue drilling.

The Century Plant may not operate or perform as intended.

We are constructing the Century Plant, a CO_2 treatment plant in Pecos County, Texas, and associated compression and pipeline facilities pursuant to an agreement with a subsidiary of Occidental. The Century Plant will be owned and operated by Occidental for the purpose of separating and removing CO_2 from natural gas delivered by us. Pursuant to a 30-year treating agreement executed simultaneously with the construction agreement, Occidental will remove CO_2 from our delivered production volumes. There are significant risks associated with the operation and performance of a facility such as the Century Plant. In addition, there is no guarantee that we will be able to construct the Century Plant within the budgeted amount or find, produce and deliver enough high CO_2 gas to satisfy our delivery obligations or that the Century Plant will operate at its designed capacity or otherwise perform as anticipated.

We may not realize the anticipated benefits of acquisitions, and integration of acquisitions may disrupt our business and management.

In the future, we may acquire other companies or large asset packages, as we have done in the past. We may not realize the anticipated benefits of an acquisition and each acquisition has numerous risks. These risks include:

- difficulty in assimilating the operations and personnel of the acquired company;
- difficulty in maintaining controls, procedures and policies during the transition and integration;
- disruption of our ongoing business and distraction of our management and employees from other opportunities and challenges;
- difficulty integrating the acquired company's accounting, management information, human resources and other administrative systems;
- inability to retain key personnel of the acquired business;
- inability to achieve the financial and strategic goals for the acquired and combined businesses;
- inability to take advantage of anticipated tax benefits;
- potential failure of the due diligence processes to identify significant problems, liabilities or other shortcomings or challenges of an acquired business;
- exposure to litigation or other claims in connection with, or inheritance of claims or litigation risk as a result of, an acquisition, including but not limited to, claims from terminated employees, customers, former stockholders or other third-parties;
- potential inability to assert that internal controls over financial reporting are effective; and
- potential incompatibility of business cultures.

Repercussions from terrorist activities or armed conflict could harm our business.

Terrorist activities, anti-terrorist efforts or other armed conflict involving the United States or its interests abroad may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If events of this nature occur and persist, the attendant political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on prevailing oil and natural gas prices and causing a reduction in our revenues. Oil and natural gas production facilities, transportation systems and storage facilities could be direct targets of terrorist attacks, and or operations could be adversely impacted if infrastructure integral to our operations is destroyed by such an attack. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

If we fail to maintain an adequate system of internal control over financial reporting, it could adversely affect our ability to accurately report our results.

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 material fraud. If we cannot provide reliable financial reports or prevent material fraud, our reputation and operating results would be harmed. Our efforts to develop and maintain our internal controls may not be successful, and we may be unable to maintain adequate controls over our financial processes and reporting in the future, including future compliance with the obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to develop or maintain effective controls, or difficulties encountered in their implementation, including those related to acquired businesses, 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.

Certain U.S. federal income tax preferences currently available with respect to oil and natural gas production may be eliminated as a result of future legislation.

Among the changes contained in President Obama's Budget Proposal for Fiscal Year 2012 is the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production. The President's budget proposes to eliminate certain tax preferences applicable to taxpayers engaged in the exploration or production of natural resources. Specifically, the budget proposes to repeal the deduction for percentage depletion with respect to wells, in which case only cost depletion would be available. It is unclear whether any such changes will be enacted or how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could negatively affect our financial condition and results of operations.

New derivatives legislation and regulation could adversely affect our ability to hedge risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") creates a new regulatory framework for oversight of derivatives transactions by the Commodity Futures Trading Commission (the "CFTC") and the SEC. Among other things, the Dodd-Frank Act subjects certain swap participants to new capital, margin and business conduct standards. In addition, the Dodd-Frank Act contemplates that where appropriate in light of outstanding exposures, trading liquidity and other factors, swaps (broadly defined to include most hedging instruments other than futures) will be required to be cleared through a registered clearing facility and traded on a designated exchange or swap execution facility. The Dodd-Frank Act also establishes a new Energy and Environmental Markets Advisory Committee to make recommendations to the CFTC regarding matters of concern to exchanges, firms, end users and regulators with respect to energy and environmental markets and also expands the CFTC's power to impose position limits on specific categories of swaps (excluding swaps entered into for *bona fide* hedging purposes).

There are some exceptions to these requirements for entities that use swaps to hedge or mitigate commercial risk. While we may qualify for one or more of such exceptions, the scope of these exceptions is uncertain and will be further defined through rulemaking proceedings at the CFTC and SEC. Further, although we may qualify for exceptions, our derivatives counterparties may be subject to new capital, margin and business conduct requirements imposed as a result of the new legislation, which may increase our transaction costs or make it more difficult for us to enter into hedging transactions on favorable terms. Our inability to enter into hedging transactions on favorable terms, or at all, could increase our operating expenses and put us at increased exposure to risks of adverse changes in oil and natural gas prices, which could adversely affect the predictability of cash flows from sales of oil and natural gas.

In January 2011, the CFTC proposed rules to establish a position limits regime on certain "core" physical-delivery contracts and their economically equivalent derivatives, some of which reference major energy commodities, including oil and natural gas. The CFTC also indicated that it intends to propose a process for determining what other swaps may be subject to position limits. Although it is not possible at this time to predict the consequences that would arise from implementing these proposals, any regulations that are adopted that subject us or our derivatives counterparties to additional capital or margin requirements relating to, or impose additional restrictions on, our trading and commodity positions could have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activity.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays as well as adversely affect our services.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions but is not subject to regulation at the federal level. The EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with results of the study anticipated to be available by late 2012, and a committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. Legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. If new laws or regulations that significantly restrict or regulate hydraulic fracturing are adopted, such legal requirements could make it more difficult or costly for us to perform fracturing to stimulate production from a formation and thereby affect the determination of whether a well is commercially viable. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce in commercial quantities.

Climate change laws and regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the oil and natural gas that we produce while the physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

On December 15, 2009, the EPA published its findings that emissions of GHGs present a danger to public health and the environment. These findings allow the agency to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. Accordingly, the EPA has proposed regulations that would require a reduction in emissions of GHGs from motor vehicles and adopted regulations that could trigger permit review for GHG emissions from certain stationary sources. In addition, on October 30, 2009, the EPA published a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, beginning in 2011 for emissions occurring in 2010. On November 30, 2010, the EPA published a final rule that expands its October 2009 final rule on reporting of GHG emissions to include owners and operators of onshore oil and natural gas production, effective December 30, 2010. Both houses of Congress have actively considered legislation to reduce emissions of GHGs and the Obama Administration has indicated its support for legislation to reduce GHG emissions through an emission allowance system. At the state level, almost one-half of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of GHGs. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with its operations or could adversely affect demand for the oil and natural gas that it produces. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our assets and operations.

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

None.

Item 2. ***Properties***

Information regarding our properties is included in Item 1. Also, refer to Note 27 of the notes to our consolidated financial statements included in Item 8 of this report.

Item 3. ***Legal Proceedings***

On or about June 27, 2008, there was a fire at the Company's Grey Ranch Plant. The Company, as owner of the plant, recovered approximately $18.7 million from its property insurance carrier for damages caused by the fire. At the time of the fire, the plant was operated by Southern Union Gas Services, Ltd. ("Southern Union Gas"). On June 4, 2010, the Company's property insurance carrier filed a lawsuit (the "lawsuit") against Southern Union Gas and its parent, Southern Union Company (together with Southern Union Gas, "Southern Union") seeking recovery for amounts paid under the policy. Southern Union, in turn, has tendered an indemnity request to Grey Ranch Plant, L.P., of which the Company is a 50% owner. Grey Ranch Plant, L.P. has not accepted or acknowledged any responsibility to indemnify Southern Union. To the extent the Company, as a 50% owner of Grey Ranch Plant, L.P., is required to fund any indemnification of Southern Union, it will pursue coverage for such a liability under its general liability insurance policy. An estimate of reasonably possible losses associated with this claim cannot be made at this time. The Company has not established any reserves relating to this claim.

On February 14, 2011, Aspen Pipeline, II, L.P. ("Aspen") filed a complaint in the District Court of Harris County, Texas against Arena Resources, Inc. and SandRidge Energy, Inc. claiming damages based upon alleged representations by Arena in connection with the construction by Aspen of a natural gas pipeline in West Texas. The plaintiff seeks damages that include the construction cost of the pipeline, which it claims approach $90.0 million. The Company intends to defend this lawsuit vigorously and, believes the plaintiff's claims are without merit. This case is in the early stages and, accordingly, an estimate of reasonably possible losses associated with this claim cannot be made at this time. The Company has not established any reserves relating to this claim.

SandRidge is a defendant in lawsuits from time to time in the normal course of business. In management's opinion, we are not currently involved in any other legal proceedings that, individually or in the aggregate, could have a material effect on our financial condition, operations or cash flows.

Item 4. *Reserved*

PART II

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

Price Range of Common Stock

Our common stock is listed on the New York Stock Exchange ("NYSE") under the symbol "SD." The range of high and low sales prices for our common stock for the periods indicated, as reported by the NYSE, is as follows:

	High	Low
2010		
Fourth Quarter	$ 7.49	$4.85
Third Quarter	$ 6.79	$3.87
Second Quarter	$ 8.03	$5.20
First Quarter	$11.08	$7.13
2009		
Fourth Quarter	$14.08	$7.97
Third Quarter	$15.00	$7.44
Second Quarter	$11.84	$6.31
First Quarter	$ 8.79	$4.49

On February 18, 2011, there were 271 record holders of our common stock.

We have neither declared nor paid any cash dividends on our common stock, and we do not anticipate declaring any dividends on our common stock in the foreseeable future. We expect to retain our cash for the operation and expansion of our business, including exploration, development and production activities. In addition, the terms of our indebtedness restrict our ability to pay dividends to holders of our common 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.

Issuer Purchases of Equity Securities

As part of our incentive compensation program, we make required tax payments on behalf of employees as their restricted 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 are recorded as treasury stock and, beginning in December 2010, are retired as repurchased. See Note 22 to the consolidated financial statements included in Item 8 of this report for further discussion of treasury stock. During the quarter ended December 31, 2010, the following shares of common stock were withheld in satisfaction of tax withholding obligations arising from the vesting of restricted stock:

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
October 1, 2010 — October 31, 2010	71,743	$5.50	N/A	N/A
November 1, 2010 — November 30, 2010	102,454	$5.21	N/A	N/A
December 1, 2010 — December 31, 2010	1,511	$7.25	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 Arena Acquisition, effective July 16, 2010, the acquisition of properties from Forest (the "Forest Acquisition"), effective December 21, 2009, and the acquisition of NEG Oil & Gas, LLC, effective November 21, 2006. The information should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 of this report and our consolidated financial statements and notes thereto contained in "Financial Statements and Supplementary Data" in Item 8 of this report. The following information is not necessarily indicative of our future results.

	Year Ended December 31,				
	2010	2009	2008	2007	2006
	(In thousands, except per share data)				
Statement of Operations Data					
Revenues	$ 931,736	$ 591,044	$ 1,181,814	$ 677,452	$388,242
Expenses					
Production	237,863	169,880	159,545	106,192	35,149
Production taxes	29,170	4,010	30,594	19,557	4,654
Drilling and services	22,368	28,380	22,872	44,211	98,436
Midstream and marketing	90,149	80,608	189,428	94,253	115,076
Depreciation and depletion — oil and natural gas	275,335	176,027	290,917	173,568	26,321
Depreciation and amortization — other	50,776	50,865	70,448	53,541	29,305
Impairment	—	1,707,150	1,867,497	—	—
General and administrative	179,565	100,256	109,372	61,780	55,634
Loss (gain) on derivative contracts	50,872	(147,527)	(211,439)	(60,732)	(12,291)
Loss (gain) on sale of assets	2,424	26,419	(9,273)	(1,777)	(1,023)
Total operating expenses	938,522	2,196,068	2,519,961	490,593	351,261
(Loss) income from operations	(6,786)	(1,605,024)	(1,338,147)	186,859	36,981
Other income (expense)					
Interest income	296	375	3,569	4,694	991
Interest expense	(247,738)	(185,691)	(147,027)	(117,185)	(16,904)
Income from equity investments	—	1,020	1,398	4,372	967
Other income, net	2,558	7,272	1,454	729	118
Total other expense	(244,884)	(177,024)	(140,606)	(107,390)	(14,828)
(Loss) income before income taxes	(251,670)	(1,782,048)	(1,478,753)	79,469	22,153
Income tax (benefit) expense	(446,680)	(8,716)	(38,328)	29,524	6,236
Net income (loss)	195,010	(1,773,332)	(1,440,425)	49,945	15,917
Less: net income (loss) attributable to noncontrolling interest	4,445	2,258	855	(276)	296
Net income (loss) attributable to SandRidge Energy, Inc	190,565	(1,775,590)	(1,441,280)	50,221	15,621
Preferred stock dividends and accretion	37,442	8,813	16,232	39,888	3,967
Income available (loss applicable) to SandRidge Energy, Inc., common stockholders	$ 153,123	$(1,784,403)	$(1,457,512)	$ 10,333	$ 11,654
Earnings Per Share Information					
Basic	$ 0.52	$ (10.20)	$ (9.36)	$ 0.09	$ 0.16
Diluted	$ 0.52	$ (10.20)	$ (9.36)	$ 0.09	$ 0.16
Weighted average number of SandRidge Energy, Inc., common shares outstanding					
Basic	291,869	175,005	155,619	108,828	73,727
Diluted	315,349	175,005	155,619	110,041	74,664

	As of December 31,				
	2010	2009	2008	2007	2006
	(In thousands)				
Balance Sheet Data					
Cash and cash equivalents	$ 5,863	$ 7,861	$ 636	$ 63,135	$ 38,948
Property, plant and equipment, net	$4,733,865	$2,433,643	$3,175,559	$3,337,410	$2,134,718
Total assets	$5,231,448	$2,780,317	$3,655,058	$3,630,566	$2,388,384
Long-term debt	$2,909,086	$2,578,938	$2,375,316	$1,067,649	$1,066,831
Redeemable convertible preferred stock(1)	$ —	$ —	$ —	$ 450,715	$ 439,643
Total equity	$1,547,483	$ (195,905)	$ 793,551	$1,771,563	$ 654,910
Total liabilities and equity	$5,231,448	$2,780,317	$3,655,058	$3,630,566	$2,388,384

(1) On May 7, 2008, we converted all of our then outstanding redeemable convertible preferred stock into shares of our common stock.

There have been no cash dividends declared or paid on our common stock.

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

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 within the meaning of the Exchange Act. These forward-looking statements may include projections and estimates concerning 2011 capital expenditures, our liquidity and capital resources, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, elements of our business strategy and other statements concerning our operations, economic performance and financial condition. Forward-looking statements are generally accompanied by words such as "estimate," "project," "predict," "believe," "expect," "anticipate," "potential," "could," "may," "foresee," "plan," "goal," "should," "intend" or other words that convey the uncertainty of future events or outcomes. We have based these forward-looking statements on our current expectations and assumptions about future events. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. The forward-looking statements in this report speak only as of the date of this report; we disclaim any obligation to update or revise these statements unless required by securities law, and we caution you not to rely on them unduly. 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 "Risk Factors" in Item 1A of this report including the following:

- the volatility of oil and natural gas prices;
- uncertainties in estimating oil and natural gas reserves;
- the need to replace the oil and natural gas reserves we produce;
- our ability to execute our growth strategy by drilling wells as planned;
- the need to drill productive, economically viable oil and natural gas wells;
- risks and liabilities associated with acquired properties;
- amount, nature and timing of capital expenditures, including future development costs, required to develop our undeveloped areas;
- concentration of operations in West Texas and the Mid-Continent;
- 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 oil and natural gas wells;
- availability of satisfactory oil and natural gas marketing and transportation;
- availability and terms of capital;
- amount and timing of proceeds of planned asset sales and asset monetizations;
- 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 oil and natural gas industry;
- general economic conditions, either internationally or domestically or in the jurisdictions in which we operate;
- costs to comply with current and future governmental regulation of the oil and natural gas industry, including environmental, health and safety laws and regulations; and
- the need to maintain adequate internal control over financial reporting.

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 should be read in conjunction with other sections of this report, including: "Business" in Item 1, "Selected Financial Data" in Item 6 and "Financial Statements and Supplementary Data" in Item 8. Our discussion and analysis relates to the following subjects:

- Overview of Our Company
- Results by Segment
- Results of Operations
- Liquidity and Capital Resources
- Critical Accounting Policies and Estimates
- New Accounting Pronouncements

Overview of Our Company

We are an independent oil and natural gas company concentrating on development and production activities related to the exploitation of our significant holdings in West Texas and the Mid-Continent area of Oklahoma and Kansas. Our primary areas of focus are the Permian Basin in West Texas, the Mississippian formation in the Mid-Continent and the WTO. We also own and operate other interests in the Mid-Continent, Cotton Valley Trend in East Texas, Gulf Coast and Gulf of Mexico. Beginning in 2009, we began expanding the oil component of our property base. Included in this expansion was the purchase of properties from Forest in December 2009 and the Arena Acquisition in July 2010, which are both in the Permian Basin area. Concurrent with our Permian acquisitions, we have focused on significantly growing oil production from our existing properties in the Mid-Continent.

We operate businesses that are complementary to our development and production activities. We own related gas gathering and treating facilities, a gas marketing business and an oil field services business. The extent to which each of these supplemental businesses contributes to our consolidated results of operations largely is determined by the amount of work each performs for third parties. Revenues and costs related to work performed by these businesses for our own account are eliminated in consolidation and, therefore, do not directly contribute to our consolidated results of operations.

We currently generate the majority of our consolidated revenues and cash flow from the production and sale of oil and natural gas. Our revenues, profitability and future growth depend substantially on prevailing prices for oil and natural gas and on our ability to find and economically develop and produce oil and natural gas reserves. Prices for oil and natural gas fluctuate widely. In order to reduce our exposure to these fluctuations, we enter into derivative commodity contracts for a portion of our anticipated future oil and natural gas production. Reducing our exposure to price volatility helps ensure that we have adequate funds available for our capital expenditure programs.

Results by Segment

We operate in three business segments: exploration and production, drilling and oil field services and midstream gas services. The All Other column in the tables below includes items not related to our reportable segments such as our CO_2 gathering and sales operations and corporate operations. Management evaluates the performance of our business segments based on operating income (loss), which is defined as segment operating revenues less operating expenses. Results of 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 business segments for the years ended December 31, 2010, 2009 and 2008 (in thousands).

	Exploration and Production	Drilling and Oil Field Services	Midstream Gas Services	All Other	Consolidated Total
Year Ended December 31, 2010					
Revenues	$ 779,450	$ 265,262	$ 275,071	$ 35,285	$ 1,355,068
Inter-segment revenue	(259)	(236,687)	(176,549)	(9,837)	(423,332)
Total revenues	$ 779,191	$ 28,575	$ 98,522	$ 25,448	$ 931,736
Operating income (loss)	$ 88,390	$ (9,970)	$ 3,959	$ (89,165)	$ (6,786)
Interest income (expense), net	496	(920)	(649)	(246,369)	(247,442)
Other income, net	1,251	—	625	682	2,558
Income (loss) before income taxes	$ 90,137	$ (10,890)	$ 3,935	$(334,852)	$ (251,670)
Capital expenditures(1)	$ 1,027,933	$ 31,658	$ 48,401	$ 21,661	$ 1,129,653
Depreciation, depletion and amortization	$ 278,110	$ 30,031	$ 4,030	$ 13,940	$ 326,111
Year Ended December 31, 2009					
Revenues	$ 457,397	$ 225,227	$ 299,580	$ 30,654	$ 1,012,858
Inter-segment revenue	(261)	(201,641)	(215,667)	(4,245)	(421,814)
Total revenues	$ 457,136	$ 23,586	$ 83,913	$ 26,409	$ 591,044
Operating loss(2)	$(1,487,914)	$ (15,166)	$ (36,989)	$ (64,955)	$(1,605,024)
Interest income (expense), net	1,121	(2,074)	(1,246)	(183,117)	(185,316)
Other income, net	4,673	—	3,365	254	8,292
Loss before income taxes	$(1,482,120)	$ (17,240)	$ (34,870)	$(247,818)	$(1,782,048)
Capital expenditures(1)	$ 555,809	$ 4,090	$ 52,425	$ 32,818	$ 645,142
Depreciation, depletion and amortization	$ 178,783	$ 28,221	$ 5,496	$ 14,392	$ 226,892
Year Ended December 31, 2008					
Revenues	$ 912,716	$ 434,963	$ 688,071	$ 22,791	$ 2,058,541
Inter-segment revenue	(220)	(387,972)	(483,933)	(4,602)	(876,727)
Total revenues	$ 912,496	$ 46,991	$ 204,138	$ 18,189	$ 1,181,814
Operating (loss) income	$(1,262,903)	$ (5,393)	$ 2,087	$ (71,938)	$(1,338,147)
Interest expense, net	(6,336)	(2,766)	—	(134,356)	(143,458)
Other income, net	1,171	1,015	398	268	2,852
(Loss) income before income taxes	$(1,268,068)	$ (7,144)	$ 2,485	$(206,026)	$(1,478,753)
Capital expenditures(1)	$ 1,909,078	$ 52,869	$ 160,460	$ 55,440	$ 2,177,847
Depreciation, depletion and amortization	$ 293,625	$ 42,077	$ 15,241	$ 10,422	$ 361,365

(1) On an accrual basis.

(2) The operating loss for the exploration and production segment for the years ended December 31, 2009 and 2008 includes non-cash full cost ceiling impairments of $1,693.3 million and $1,855.0 million, respectively, on our oil and natural gas properties. The operating loss for the midstream gas services segment for the year ended December 31, 2009 includes a $26.1 million loss on the sale of our gathering and compression assets in the Piñon Field.

Exploration and Production Segment

The primary factors affecting the financial results of our exploration and production segment are the prices we receive for our oil and natural gas production, the quantity of oil and natural gas we produce and changes in the fair value of commodity derivative contracts we use to reduce the volatility of the prices we receive for our oil and natural gas production. Annual comparisons of production and price data are presented in the tables below. Changes in our results for these periods reflect the strategic movement toward increased oil production in 2010, including the acquisition of oil and natural gas properties from Forest in December 2009 and Arena in July 2010, which increased production volumes and associated oil and natural gas revenues.

	Year Ended December 31,		Change	
	2010	2009	Amount	Percent
Production data				
Oil (MBbls)	7,386	2,894	4,492	155.2%
Natural gas (MMcf)	76,226	87,461	(11,235)	(12.8)%
Total volumes (MBoe)	20,090	17,471	2,619	15.0%
Total volumes (MMcfe)	120,542	104,823	15,719	15.0%
Average daily total volumes (MBoe/d)	55.0	47.9	7.1	15.0%
Average daily total volumes (MMcfe/d)	330.3	287.2	43.1	15.0%
Average prices — as reported(1)				
Oil (per Bbl)(2)	$ 66.89	$ 55.62	$ 11.27	20.3%
Natural gas (per Mcf)	$ 3.68	$ 3.36	$ 0.32	9.5%
Total (per Boe)	$ 38.56	$ 26.03	$ 12.53	48.1%
Total (per Mcfe)	$ 6.43	$ 4.34	$ 2.09	48.1%
Average prices — including impact of derivative contract settlements				
Oil (per Bbl)(2)	$ 68.15	$ 59.69	$ 8.46	14.2%
Natural gas (per Mcf)	$ 6.20	$ 7.20	$ (1.00)	(13.9)%
Total (per Boe)	$ 48.58	$ 45.95	$ 2.63	5.7%
Total (per Mcfe)	$ 8.10	$ 7.66	$ 0.44	5.7%

	Year Ended December 31,		Change	
	2009	2008	Amount	Percent
Production data				
Oil (MBbls)	2,894	2,334	560	24.0%
Natural gas (MMcf)	87,461	87,402	59	0.1%
Total volumes (MBoe)	17,471	16,901	570	3.4%
Total volumes (MMcfe)	104,823	101,405	3,418	3.4%
Average daily total volumes (MBoe/d)	47.9	46.2	1.7	3.6%
Average daily total volumes (MMcfe/d)	287.2	277.1	10.1	3.6%
Average prices — as reported(1)				
Oil (per Bbl)(2)	$ 55.62	$ 91.54	$ (35.92)	(39.2)%
Natural gas (per Mcf)	$ 3.36	$ 7.95	$ (4.59)	(57.7)%
Total (per Boe)	$ 26.03	$ 53.76	$ (27.73)	(51.6)%
Total (per Mcfe)	$ 4.34	$ 8.96	$ (4.62)	(51.6)%
Average prices — including impact of derivative contract settlements				
Oil (per Bbl)(2)	$ 59.69	$ 88.09	$ (28.40)	(32.2)%
Natural gas (per Mcf)	$ 7.20	$ 7.90	$ (0.70)	(8.9)%
Total (per Boe)	$ 45.95	$ 52.98	$ (7.03)	(13.3)%
Total (per Mcfe)	$ 7.66	$ 8.83	$ (1.17)	(13.3)%

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

(2) Includes natural gas liquids.

As of December 31, 2010, we had 545.9 MMBoe or 3,275.3 Bcfe of estimated net proved reserves with a PV-10 of $4,509.2 million, compared to 218.7 MMBoe or 1,312.2 Bcfe of estimated net proved reserves with a PV-10 of $1,561.0 million as of December 31, 2009. Our Standardized Measure was $3,683.5 million at December 31, 2010 compared to $1,561.0 million at December 31, 2009 and $2,220.6 million at December 31, 2008. The increase in PV-10 in 2010 is primarily attributable to reserves acquired in the Arena Acquisition and higher commodity prices during 2010 compared to 2009. For a discussion of PV-10 and reconciliation to Standardized Measure, see "Business — Our Business and Primary Operations — Proved Reserves" in Item 1 of this report.

Exploration and Production Segment — Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

Exploration and production segment revenues increased $322.1 million, or 70.5%, to $779.2 million in the year ended December 31, 2010 from $457.1 million in 2009, primarily as a result of the 155.2% increase in oil production, slightly offset by the 12.8% decrease in natural gas production volumes. Also contributing to the increase was a 48.1% increase in the combined average price we received on our oil and natural gas production. In the year ended December 31, 2010, oil production increased by 4,492 MBbls to 7,386 MBbls. The increase in oil production was due to the addition of Permian Basin properties acquired from Forest and Arena, and a focus on increased oil drilling in 2010. We produced 3,774 MBbls of oil for the year ended December 31, 2010 from the properties acquired from Forest and Arena. The 11.2 Bcf decrease in natural gas production was a result of the decline in the number of rigs drilling for natural gas during 2010 due to depressed natural gas prices and our strategic shift to increased oil drilling.

The average price received for our oil production increased 20.3%, or $11.27 per barrel, to $66.89 per barrel during the year ended December 31, 2010 from $55.62 per barrel in 2009. The average price we received for our natural gas production for the year ended December 31, 2010 increased 9.5%, or $0.32 per Mcf, to $3.68 per Mcf from $3.36 per Mcf in 2009. Including the impact of derivative contract settlements, the effective price received for oil for the year ended December 31, 2010 was $68.15 per Bbl compared to $59.69 per Bbl in 2009. Including the impact of derivative contract settlements, the effective price received for natural gas for the year ended December 31, 2010 was $6.20 per Mcf compared to $7.20 per Mcf in 2009. Due to the long-term nature of our investment in the development of our properties, we enter into oil and natural gas swaps and collars for a portion of our production in order to stabilize future cash inflows for planning purposes. Our derivative contracts are not designated as hedges and, as a result, gains or losses on commodity derivative contracts are recorded as a component of operating expenses. Internally, management views the settlement of such derivative contracts as adjustments to the price received for oil and natural gas production to determine "effective prices." Realized gains or losses from the settlement of derivative contracts with contractual maturities outside of the reporting period are not considered in the calculation of "effective prices."

During the year ended December 31, 2010, the exploration and production segment reported a $50.9 million net loss on our commodity derivative positions ($224.3 million realized gain and $275.2 million unrealized loss) compared to a $147.5 million net gain on our commodity derivative positions ($348.0 million realized gain and $200.5 million unrealized loss) in 2009. The realized gain of $224.3 million for the year ended December 31, 2010 was primarily due to lower natural gas prices at the time of settlement compared to the contract price. Realized gains totaling $114.4 million resulting from settlements of commodity derivative contracts with original contractual maturities after the quarterly period in which they were settled were included in the realized gain for the year ended December 31, 2010. Unrealized gains or losses on derivative contracts represent the change in fair value of open derivative contracts during the period. The unrealized loss on our commodity contracts recorded during the year ended December 31, 2010 was primarily attributable to an increase in average oil prices at December 31, 2010 compared to the average oil prices at December 31, 2009 or the contract price for contracts entered into during 2010 and the settlement of natural gas price swaps during the year ended December 31, 2010. The unrealized loss for the year ended December 31, 2009 was attributable to increased average oil and natural gas prices and decreases in the price differentials on our basis swaps at December 31, 2009.

For the year ended December 31, 2010, we had operating income of $88.4 million in our exploration and production segment compared to an operating loss of $1,487.9 million in 2009. The $320.1 million increase in oil and natural gas revenues and the absence of a full cost pool ceiling impairment were partially offset by the $50.9 million net loss on commodity derivative contracts, a $68.0 million increase in production expenses, a $25.2 million increase in production taxes and a $99.3 million increase in depreciation and depletion on oil and natural gas properties. See discussion of production expense, production taxes and depreciation and depletion under "Consolidated Results of Operations" below.

Exploration and Production Segment — Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Exploration and production segment revenues decreased 49.9% to $457.1 million for the year ended December 31, 2009 from $912.5 million in 2008, as a result of a 51.6% decrease in the average price we received for the oil and natural gas we produced, offset slightly by a 3.4% increase in combined production volumes. During 2009, we increased oil production by 560 MBbls to 2,894 MBbls and increased natural gas production slightly by 59 MMcf to 87.5 Bcf. The total combined 570 MBoe or 3.4 Bcfe increase in production was primarily due to the increased oil production resulting from new wells in West Texas and the Permian Basin.

The average price received for our oil production decreased to $55.62 per Bbl from $91.54 per Bbl in 2008. The average price we received for our natural gas production for the year ended December 31, 2009 decreased $4.59 per Mcf, or 57.7%, to $3.36 per Mcf from $7.95 per Mcf in 2008. The average price we received for our oil and natural gas production was negatively impacted by the continued decline in oil and natural gas prices experienced by the industry during 2009. Our oil derivative contract settlements increased our effective price received for oil by $4.07 per Bbl to $59.69 per Bbl for the year ended December 31, 2009. Our oil derivative contract settlements decreased our effective price received for oil by $3.45 per Bbl to $88.09 per Bbl for the year ended December 31, 2008. Including the impact of derivative contract settlements, the effective average price received for natural gas for the year ended December 31, 2009 was $7.20 per Mcf compared to $7.90 per Mcf during 2008.

During the year ended December 31, 2009, the exploration and production segment reported a $147.5 million net gain on our commodity derivative contracts ($348.0 million realized gain and $200.5 million unrealized loss) compared to a $211.4 million net gain ($13.0 million realized loss and $224.4 million unrealized gain) in 2008. The realized gain of $348.0 million for the year ended December 31, 2009 was primarily due to a decline in natural gas prices at the time of settlement compared to the contract price. The unrealized loss on oil and natural gas derivative contracts recorded during the year ended December 31, 2009 was attributable to an increase in average oil and natural gas prices at December 31, 2009 compared to the average oil and natural gas prices at December 31, 2008 or the contract price for contracts entered into during 2009.

For the year ended December 31, 2009, we had an operating loss of $1,487.9 million in our exploration and production segment, compared to an operating loss of $1,262.9 million in 2008. The operating loss for the year ended December 31, 2009 was attributable to the $455.4 million decrease in exploration and production segment revenues and the full cost ceiling impairments totaling $1,693.3 million, partially offset by $147.5 million in net gain on our commodity derivative contracts and a $114.9 million decrease in depreciation and depletion on oil and natural gas properties due to the decrease in the average depreciation and depletion per unit. The 2009 full cost ceiling impairments were the result of the decline in the future value of our reserves based on the oil and natural gas prices at March 31, 2009 and the 12-month average prices at December 31, 2009.

Under SEC rules that became effective December 31, 2009, oil and natural gas reserves were calculated based on the average price during the 12-month period, using the first-day-of-the-month price for each month in the period instead of the one-day period end pricing method previously used. As a result of lower oil and natural gas prices during 2009, which were used to determine the future value of our reserves, we were required to record a ceiling impairment of $388.9 million at December 31, 2009, in addition to the $1,304.4 million ceiling impairment recorded at March 31, 2009.

Drilling and Oil Field Services Segment

The financial results of our drilling and oil field services segment depend primarily on demand and the price we can charge for our services. In addition to providing drilling services, our oil field services business also conducts operations that complement our exploration and production segment such as providing pulling units, trucking, rental tools, location and road construction and roustabout services. On a consolidated basis, drilling and oil field service revenues earned and expenses incurred in performing services for third parties, including third party working interests in wells we operate, are included in drilling and services revenues and expenses while drilling and oil field service revenues earned and expenses incurred in performing services for our own account are eliminated in consolidation.

As of December 31, 2010, we owned 31 drilling rigs, through Lariat. The table below presents a summary of our rigs for each of the years ended December 31, 2010, 2009 and 2008:

	December 31,		
Rigs	**2010**	**2009**	**2008**
Working for SandRidge	20	14	13
Working for third parties	9	2	3
Idle	2	14	12
Total operational	31	30	28
Non-operational	—	1	3
Total rigs	31	31	31

Until April 15, 2009, we indirectly owned, through Lariat and its partner Clayton Williams Energy, Inc. ("CWEI"), an additional 11 operational rigs through an investment in Larclay L.P. ("Larclay"). Although our ownership in Larclay afforded us access to Larclay's rigs, we did not control Larclay, and, therefore, did not consolidate the results of its operations with ours. Only the activities of our wholly owned drilling and oil field services subsidiaries are included in the financial results of our drilling and oil field services segment. On April 15, 2009, Lariat completed an assignment to CWEI of Lariat's 50% equity interest in Larclay pursuant to the terms of an Assignment and Assumption Agreement (the "Larclay Assignment") entered into between Lariat and CWEI. Pursuant to the Larclay Assignment, Lariat assigned all of its right, title and interest in and to Larclay to CWEI effective as of April 15, 2009, and CWEI assumed all of the obligations and liabilities of Lariat relating to Larclay. We fully impaired our investment in and notes receivable due from Larclay at December 31, 2008. There were no additional losses on Larclay during the year ended December 31, 2009 or as a result of the Larclay Assignment.

Drilling and Oil Field Services Segment — Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

Drilling and oil field services segment revenues increased to $28.6 million in the year ended December 31, 2010 from $23.6 million in the year ended December 31, 2009 and drilling and oil field services segment expenses decreased $0.2 million to $38.5 million during the same period. The increase in revenues resulted in a reduced operating loss of $10.0 million in the year ended December 31, 2010 compared to $15.2 million for the same period in 2009. The increase in revenues was primarily attributable to an increase in services performed for third parties during 2010 as we had more rigs drilling for third parties during 2010 than during 2009. During 2010, an average of four rigs were working for third parties compared to an average of one rig working for third parties during 2009. Additionally, the average daily rate received per rig working for third parties increased to an average of $14,287 per rig per working day during 2010 compared to an average of $11,398 per rig per working day during 2009. The reduced, or stand-by, rates received on two of our rigs during 2009 resulted in a lower average rate per rig per working day in 2009. During 2010, none of our rigs received stand-by rates.

Drilling and Oil Field Services Segment — Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Drilling and oil field services segment revenues decreased to $23.6 million for the year ended December 31, 2009 from $47.0 million for the year ended December 31, 2008. This resulted in an operating loss of $15.2 million during 2009 compared to an operating loss of $5.4 million during 2008. The decline in revenues and operating income was primarily attributable to a decrease in the number of our rigs operating and decreases in services performed for third parties as well as lower operating margins during 2009 compared to 2008. During 2009, an average of 8.3 of the 30 operational rigs we owned were working compared to an average of 25.5 of the 28 operational rigs working during 2008. Additionally, the average daily rate received per rig working for third parties declined to an average of $11,398 per rig per working day during 2009 from an average of $14,217 per rig per working day during 2008. We received reduced, or stand-by, rates on two of our rigs during 2009, which resulted in a lower average rate per rig per working day for the year ended December 31, 2009 than the comparable period in 2008.

Midstream Gas Services Segment

Midstream gas services segment revenues consist mostly of revenue from gas marketing, which is a very low-margin business. Midstream gas services are primarily undertaken to realize incremental margins on natural gas purchased at the wellhead, and provide value-added services to customers. On a consolidated basis, midstream and marketing revenues represent natural gas sold on behalf of third parties and the fees we charge related to gathering, compressing and treating this natural gas. Gas marketing operating costs represent payments made to third parties for the proceeds from the sale of natural gas owned by such parties, net of any applicable margin and actual costs we charge to gather, compress and treat the natural gas. 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. The primary factors affecting the results of our midstream gas services segment are the quantity of natural gas we gather, treat and market and the prices we pay and receive for natural gas.

In June 2009, we completed the sale of our gathering and compression assets located in the Piñon Field. Net proceeds from the sale were approximately $197.5 million, which resulted in a loss on the sale of $26.1 million. In conjunction with the sale, we entered into a gas gathering agreement and an operations and maintenance agreement. Under the gas gathering agreement, we have dedicated our Piñon Field acreage for priority gathering services for a period of 20 years and we will pay a fee for such services that was negotiated at arms' length. Pursuant to the operations and maintenance agreement, we will operate and maintain the gathering system assets sold for a period of 20 years unless we or the buyer of the assets chooses to terminate the agreement.

Grey Ranch Plant, L.P. ("GRLP") is a limited partnership that operates the Grey Ranch plant we own that is located in Pecos County, Texas. We purchased our investment in GRLP during 2003. During October 2009, we executed amendments to certain agreements related to the ownership and operation of GRLP. As a result of these amendments, we became the primary beneficiary of GRLP. Due to this change, we began consolidating the activity of GRLP in our midstream gas services segment prospectively beginning on the effective date of the amendments, October 1, 2009.

Midstream Gas Services Segment — Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

Midstream gas services segment revenues for the year ended December 31, 2010 were $98.5 million compared to $83.9 million in the same period in 2009. Operating income was $4.0 million for the year ended December 31, 2010 compared to an operating loss of $37.0 million in 2009. The increase in natural gas prices for third party volumes we marketed in the year ended December 31, 2010 compared to 2009 contributed to the increase in revenues. The consolidation of GRLP activity into the midstream gas services segment for the year ended December 31, 2010 also contributed to the increase in midstream gas services segment revenues and to the increase in operating income. Prior to October 1, 2009 when we began consolidating GRLP, our share of GRLP activity was reported as income from equity investments. The 2010 increase in operating income was primarily due to the inclusion of a $26.1 million loss on the sale of our gathering and compression assets and a $10.0 million impairment on our spare parts inventory in the year ended December 31, 2009.

Midstream Gas Services Segment — Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Midstream gas services segment revenues for the year ended December 31, 2009 were $83.9 million compared to $204.1 million in 2008. The decrease in midstream gas services revenues was attributable to an overall decrease in natural gas prices in 2009 compared to 2008. Operating costs decreased in proportion to revenue based on the decrease in natural gas prices paid in 2009 compared to 2008. Profit margin for 2009 was 6.2% compared to a profit margin of 8.6% for 2008. The operating loss of $37.0 million for 2009 compared to operating income of $2.1 million in 2008 was primarily attributable to the loss on the sale of our gathering and compression assets. Also contributing to the operating loss was the impairment of spare parts inventory recorded in 2009.

Consolidated Results of Operations

Year Ended December 31, 2010 Compared to the Year Ended December 31, 2009

Revenues. Total revenues increased 57.6% to $931.7 million for the year ended December 31, 2010 from $591.0 million in 2009. This increase is primarily due to the increase in oil and natural gas sales that resulted from increased oil production and increased prices received on our oil and natural gas production.

	Year Ended December 31,			
	2010	2009	$ Change	% Change
	(In thousands)			
Revenues				
Oil and natural gas	$774,763	$454,705	$320,058	70.4%
Drilling and services	28,543	23,586	4,957	21.0%
Midstream and marketing	100,118	86,028	14,090	16.4%
Other	28,312	26,725	1,587	5.9%
Total revenues	$931,736	$591,044	$340,692	57.6%

Total oil and natural gas revenues increased $320.1 million for the year ended December 31, 2010 compared to 2009, primarily as a result of increased oil production, offset slightly by decreased natural gas production, and increased prices received for our oil and natural gas production. The increase in oil production was primarily due to the addition of properties acquired from Forest and Arena and a focus on increased oil drilling in 2010. The combined average price received, excluding the impact of derivative contracts, for our oil and natural gas production increased 48.1% in 2010 to $38.56 per Boe or $6.43 per Mcfe compared to $26.03 per Boe or $4.34 per Mcfe in 2009.

Drilling and services revenues increased 21.0% for the year ended December 31, 2010 compared to 2009. The increase was due to an increase in the number of rigs drilling for third parties and an increase in the average revenue per rig per day.

Midstream and marketing revenues increased $14.1 million, or 16.4%, for the year ended December 31, 2010 compared to 2009. The increase in revenues was primarily attributable to the inclusion of GRLP activity for the year ended December 31, 2010, as previously discussed. Also contributing to the increase was an increase in the price of natural gas marketed for third parties.

Operating Costs and Expenses. Total operating costs and expenses decreased to $938.5 million during 2010, compared to $2,196.1 million in 2009, primarily due to the absence of a full cost ceiling impairment during 2010. The absence of a ceiling impairment was partially offset by increases in production expense, production taxes, midstream and marketing expense, depreciation and depletion, general and administrative expense and the loss on derivative contracts.

	Year Ended December 31,			
	2010	**2009**	**$ Change**	**% Change**
	(In thousands)			
Operating costs and expenses				
Production	$237,863	$ 169,880	$ 67,983	40.0%
Production taxes	29,170	4,010	25,160	627.4%
Drilling and services	22,368	28,380	(6,012)	(21.2)%
Midstream and marketing	90,149	80,608	9,541	11.8%
Depreciation and depletion — oil and natural gas	275,335	176,027	99,308	56.4%
Depreciation and amortization — other	50,776	50,865	(89)	(0.2)%
Impairment	—	1,707,150	(1,707,150)	(100.0)%
General and administrative	179,565	100,256	79,309	79.1%
Loss (gain) on derivative contracts	50,872	(147,527)	198,399	(134.5)%
Loss on sale of assets	2,424	26,419	(23,995)	(90.8)%
Total operating costs and expenses	$938,522	$2,196,068	$(1,257,546)	(57.3)%

Production expense includes the costs associated with our exploration and production activities, including, but not limited to, lease operating expense and treating costs. Production expense increased $68.0 million for the year ended December 31, 2010 compared to 2009 primarily due to the addition of operating expenses associated with properties acquired from Forest and Arena. Also contributing to the increase were higher production costs associated with oil volumes compared to production costs on natural gas volumes. Oil production increased by 4,492 MBbls in 2010 to 7,386 MBbls from the comparable period in 2009.

Production taxes increased $25.2 million due to the additional taxes for production from properties acquired from Forest and Arena and a decrease in the amount of high-cost gas severance tax refunds received in the year ended December 31, 2010 compared to 2009. As a result, production taxes on a unit-of-production basis increased from $0.23 per Boe or $0.04 per Mcfe for 2009 to $1.45 per Boe or $0.24 per Mcfe for 2010.

Drilling and services expenses, which include operating expenses attributable to the drilling and oil field services segment and our CO_2 services companies, decreased $6.0 million, or 21.2%, for the year ended December 31, 2010 compared to 2009 due, in part, to higher CO_2 volumes used by us in the completion operations of wells on our oil and natural gas properties. Also contributing to the decrease in expense was the overall increase in rig activity and higher profit margins experienced in 2010, which resulted in a higher amount of costs associated with the drilling business being allocated to the full cost pool and a decreased amount of such costs being expensed.

Midstream and marketing expenses increased $9.5 million, or 11.8%, due to the consolidation of GRLP activity as well as increased prices paid for natural gas purchased from third parties during 2010 compared to 2009.

Depreciation and depletion of our oil and natural gas properties increased to $275.3 million for the year ended December 31, 2010 from $176.0 million in the same period in 2009. The increase was primarily due to an increase in our depreciation and depletion rate to $13.70 per Boe or $2.28 per Mcfe in 2010 from $10.08 per Boe or $1.68 per Mcfe in 2009 as a result of an increase to our depreciable oil and natural gas properties, primarily due to the acquisition of properties from Arena in July 2010 and Forest in December 2009.

During 2009, we reduced the carrying value of our oil and natural gas properties by $1,693.3 million due to full cost ceiling limitations at both March 31, 2009 and December 31, 2009. There were no full cost ceiling impairments recorded during 2010. There were additional impairment expenses of $10.0 million and $3.9 million in 2009 related to the decline in market value of our spare parts inventory and buildings that we determined will not have use or value in the future, respectively.

General and administrative expenses increased $79.3 million, or 79.1%, for the year ended December 31, 2010 compared to 2009 due, in part, to a $25.8 million increase in compensation costs resulting from an increase in non-cash stock compensation and an increase in the number of employees and severance expense during 2010. The increased compensation costs are primarily a result of the Arena Acquisition. Also contributing to the increase was $17.0 million in costs incurred related to our acquisition of Arena, $18.2 million for the settlement of a dispute with certain working interest owners and an increase of approximately $8.0 million in professional services rendered to us.

We recorded a net loss of $50.9 million ($224.3 million realized gain and $275.2 million unrealized loss) on our commodity derivative contracts for the year ended December 31, 2010 compared to a net gain of $147.5 million ($348.0 million realized gain and $200.5 million unrealized loss) in 2009. See further discussion of gains and losses on commodity derivative contracts under "Results by Segment — Exploration and Production Segment" above.

Loss on sale of assets decreased $24.0 million, or 90.8%, for the year ended December 31, 2010 from a $26.4 million loss in 2009, primarily due to a $26.1 million loss recorded on the sale of our gathering and compression assets during the 2009 period.

Other Income (Expense). Total other expense increased to $244.9 million for the year ended December 31, 2010 from $177.0 million in 2009. The increase is reflected in the table below.

	Year Ended December 31, 2010	Year Ended December 31, 2009	$ Change	% Change
	(In thousands)			
Other income (expense)				
Interest income	$ 296	$ 375	$ (79)	(21.1)%
Interest expense	(247,738)	(185,691)	(62,047)	33.4%
Income from equity investments	—	1,020	(1,020)	(100.0)%
Other income, net	2,558	7,272	(4,714)	(64.8)%
Total other expense	(244,884)	(177,024)	(67,860)	38.3%
Loss before income taxes	(251,670)	(1,782,048)	1,530,378	(85.9)%
Income tax benefit	(446,680)	(8,716)	(437,964)	5,024.8%
Net income (loss)	$ 195,010	$(1,773,332)	$1,968,342	(111.0)%

Interest expense increased to $247.7 million for the year ended December 31, 2010 from $185.7 million in 2009. This increase was primarily attributable to higher average debt balances outstanding during the year ended December 31, 2010 compared to 2009 mainly due to increased borrowings under our senior credit facility during the period and the issuance of our 9.875% Senior Notes in May 2009 and our 8.75% Senior Notes in December 2009. Also contributing to the increase was a $16.5 million net loss on our interest rate swaps for the year ended December 31, 2010 compared to a $5.8 million net loss for 2009.

Other income, net decreased to $2.6 million in 2010 from $7.3 million in 2009. The decrease was due primarily to a break-up fee received in 2009 as a result of the termination of an acquisition transaction.

We reported an income tax benefit of $446.7 million, net of income tax expense attributable to noncontrolling interest, for the year ended December 31, 2010, compared to an income tax benefit of $8.7 million for 2009. The increase was primarily due to the release of a portion of our valuation allowance against our net deferred tax asset as a result of the Arena Acquisition. Net deferred tax liabilities recorded as a result of the Arena Acquisition in July 2010 reduced our existing net deferred tax asset position, allowing a corresponding reduction in the valuation allowance against the net deferred tax asset.

Year Ended December 31, 2009 Compared to the Year Ended December 31, 2008

Revenues. Total revenues decreased 50.0% to $591.0 million for the year ended December 31, 2009 from $1,181.8 million in 2008. This decrease was primarily due to a $454.0 million decrease in oil and natural gas sales and a $121.6 million decrease in midstream and marketing revenues.

	Year Ended December 31,			
	2009	2008	$ Change	% Change
	(In thousands)			
Revenues				
Oil and natural gas	$454,705	$ 908,689	$(453,984)	(50.0)%
Drilling and services	23,586	46,855	(23,269)	(49.7)%
Midstream and marketing	86,028	207,602	(121,574)	(58.6)%
Other	26,725	18,668	8,057	43.2%
Total revenues	$591,044	$1,181,814	$(590,770)	(50.0)%

Total oil and natural gas revenues decreased $454.0 million to $454.7 million for the year ended December 31, 2009, compared to $908.7 million in 2008, primarily as a result of the decrease in oil and natural gas prices received for our production. The average price received, excluding the impact of derivative contracts, for our oil and natural gas production decreased 51.6% in 2009 to a combined equivalent price of $26.03 per Boe or $4.34 per Mcfe compared to $53.76 per Boe or $8.96 per Mcfe in 2008. The average price we received for our oil and natural gas production was negatively impacted by the decline in oil and natural gas prices experienced by the oil and natural gas industry during 2009. Total natural gas production increased 0.1% to 87.5 Bcf in 2009 compared to 87.4 Bcf in 2008, while oil production increased 24.0% to 2,894 MBbls in 2009 from 2,334 MBbls in 2008.

Drilling and services revenues decreased 49.7% to $23.6 million in 2009 compared to $46.9 million in 2008. The decline in revenues was due to a decrease in rigs operating for and services performed for third parties and the decline in the average daily rate received per rig working for third parties. The average daily rate we received per rig working for third parties declined to an average of $11,398 per rig per working day during 2009 from an average of $14,217 per rig per working day during 2008.

Midstream and marketing revenues decreased $121.6 million, or 58.6%, to $86.0 million for the year ended December 31, 2009, compared to $207.6 million in 2008. The decrease was attributable to the decrease in prices for natural gas that we sold on behalf of third parties in 2009 compared to 2008.

Other revenues increased to $26.7 million for the year ended December 31, 2009 from $18.7 million for 2008. The increase was primarily due to higher CO_2 volumes sold to third parties during 2009 than 2008.

Operating Costs and Expenses. Total operating costs and expenses decreased to $2,196.1 million during 2009, compared to $2,520.0 million in 2008, primarily as a result of decreases in our midstream and marketing expenses, depreciation and depletion and the full cost ceiling impairment.

	Year Ended December 31, 2009	Year Ended December 31, 2008	$ Change	% Change
	(In thousands)			
Operating costs and expenses				
Production	$ 169,880	$ 159,545	$ 10,335	6.5%
Production taxes	4,010	30,594	(26,584)	(86.9)%
Drilling and services	28,380	22,872	5,508	24.1%
Midstream and marketing	80,608	189,428	(108,820)	(57.4)%
Depreciation and depletion — oil and natural gas	176,027	290,917	(114,890)	(39.5)%
Depreciation and amortization — other	50,865	70,448	(19,583)	(27.8)%
Impairment	1,707,150	1,867,497	(160,347)	(8.6)%
General and administrative	100,256	109,372	(9,116)	(8.3)%
Gain on derivative instruments	(147,527)	(211,439)	63,912	(30.2)%
Loss (gain) on sale of assets	26,419	(9,273)	35,692	(384.9)%
Total operating costs and expenses	$2,196,068	$2,519,961	$(323,893)	(12.9)%

Production expenses increased slightly to $169.9 million for the year ended December 31, 2009, compared to $159.5 million in 2008, primarily due to the slight increase in production from our 2009 drilling activity in the Permian Basin and West Texas.

Production taxes decreased $26.6 million, or 86.9%, to $4.0 million for the year ended December 31, 2009, compared to $30.6 million in 2008, as a result of severance tax refunds totaling approximately $13.2 million in 2009 and the decreased prices received for production. As a result, production taxes on a unit-of-production basis decreased from $1.80 per Boe or $0.30 per Mcfe for 2008 to $0.23 per Boe or $0.04 per Mcfe for 2009.

Drilling and services expenses increased $5.5 million, or 24.1%, to $28.4 million in 2009 compared to $22.9 million in 2008. The increase was primarily due to less rig activity conducted on our properties and lower profit margins in 2009, which resulted in a lower amount of costs associated with the drilling business being allocated to the full cost pool and an increased amount of such costs being expensed.

Midstream and marketing expenses decreased $108.8 million, or 57.4%, to $80.6 million in 2009 compared to $189.4 million in 2008, due primarily to lower prices paid for natural gas that we sold on behalf of third parties during 2009 than 2008.

Depreciation and depletion for our oil and natural gas properties decreased to $176.0 million during 2009 from $290.9 million in 2008. Our average depreciation and depletion decreased to $10.08 per Boe or $1.68 per Mcfe from $17.21 per Boe or $2.87 per Mcfe in 2008 as a result of the cumulative full cost ceiling impairment, which reduced the carrying value of our oil and natural gas properties. The effect of the decrease in depreciation and depletion per unit was slightly offset by the 3.4% increase in production for the year ended December 31, 2009 compared to 2008.

Depreciation and amortization for our other assets consists primarily of depreciation of our drilling rigs, midstream gathering and compression facilities and other equipment. The $19.6 million decrease in depreciation and amortization for our other assets was attributable primarily to the change in asset lives of certain of our drilling, oil field service, midstream and other assets to align with industry average lives for similar assets. We calculate depreciation of property and equipment using the straight-line method over the estimated useful lives of the assets, which range from 3 to 39 years.

During 2009, we recorded a cumulative non-cash impairment charge of $1,693.3 million on our properties as total capitalized costs of our oil and natural gas properties exceeded our full cost ceiling limitation at both March 31, 2009 and December 31, 2009. Additional impairment expenses of $10.0 million and $3.9 million in 2009 were related to the decline in market value of our spare parts inventory and buildings that we determined will not have use or value in the future, respectively. At December 31, 2008, we recorded a non-cash full cost ceiling limitation impairment charge of $1,855.0 million on our properties. Additional impairment expenses in 2008 related to the impairment of our investment in and notes receivable due from Larclay.

General and administrative expenses decreased 8.3% to $100.3 million in 2009 from $109.4 million in 2008. The decrease was attributable, in part, to lower administrative costs due to the decrease in the number of people we employed for the year. As of December 31, 2009, we had 466 corporate employees compared to 528 at December 31, 2008. Also contributing to the decrease were lower professional services and office costs as a result of focused cost control efforts. General and administrative expenses included non-cash stock compensation expense, net of amounts capitalized, of $20.5 million for the year ended December 31, 2009 compared to $18.8 million in 2008. Corporate salaries and wages were partially offset by capitalized general and administrative expenses of $22.3 million, which included $4.3 million of capitalized stock compensation, for 2009 and $19.1 million for 2008. In accordance with the full cost method of accounting, we capitalize, into the full cost pool, 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. There was no stock compensation capitalized in 2008.

Due to the decline in average oil and natural gas prices during 2009, we recorded a net gain of $147.5 million ($348.0 million realized gain and $200.5 million unrealized loss) on our derivatives contracts for 2009 compared to a $211.4 million net gain ($13.0 million realized loss and $224.4 million unrealized gain) in 2008. The realized gain of $348.0 million for the year ended December 31, 2009 was primarily due to a decline in natural gas prices at the time of settlement compared to the contract price. The unrealized loss recorded in 2009 was attributable to an increase in average natural gas prices at December 31, 2009 compared to December 31, 2008 or the contract date for contracts entered into during 2009.

The loss on sale of assets for the year ended December 31, 2009 was primarily due to the $26.1 million loss on the sale of our gathering and compression assets located in the Piñon Field. For the year ended December 31, 2008, the gain on sale of assets was attributable to the approximately $7.2 million gain on the sale of our assets located in the Piceance Basin of Colorado.

Other Income (Expense). Total other expense increased to $177.0 million for the year ended December 31, 2009 from $140.6 million in 2008. The increase is reflected in the table below.

	Year Ended December 31,			
	2009	2008	$ Change	% Change
		(In thousands)		
Other income (expense)				
Interest income	$ 375	$ 3,569	$ (3,194)	(89.5)%
Interest expense	(185,691)	(147,027)	(38,664)	26.3%
Income from equity investments	1,020	1,398	(378)	(27.0)%
Other income, net	7,272	1,454	5,818	400.1%
Total other expense	(177,024)	(140,606)	(36,418)	25.9%
Loss before income taxes	(1,782,048)	(1,478,753)	(303,295)	20.5%
Income tax benefit	(8,716)	(38,328)	29,612	(77.3)%
Net loss	$(1,773,332)	$(1,440,425)	$(332,907)	23.1%

Interest income decreased to $0.4 million in 2009 from $3.6 million in 2008. This decrease was generally due to lower excess cash levels during 2009 compared to 2008.

Interest expense increased to $185.7 million in 2009, from $147.0 million, net of $0.4 million of capitalized interest, in 2008. The increase in interest expense for 2009 was the result of higher average debt balances outstanding during 2009 compared to 2008.

During the year ended December 31, 2009, we reported income from equity investments of $1.0 million compared to $1.4 million in 2008. The slight decline in income from equity investments was due to the consolidation of GRLP beginning October 1, 2009 and Lariat's assignment of its 50% equity interest in Larclay to CWEI on April 15, 2009.

Other income, net increased to $7.3 million in 2009 from $1.5 million in 2008. The increase was generally due to $4.5 million of a $7.0 million break-up fee received in 2009 as a result of the termination of an acquisition transaction. Approximately $2.5 million of the break-up fee was recorded in general and administrative expenses to offset costs we incurred during the acquisition process.

We reported an income tax benefit of $8.7 million for the year ended December 31, 2009 compared to an income tax benefit of $38.3 million in 2008. The 2009 income tax benefit represented an effective income tax rate of 0.5% compared to an effective income tax rate of 2.6% in 2008. The lower effective income tax rate associated with the net loss attributable to us before income taxes of $1,784.3 million was predominantly due to a valuation allowance on the net deferred tax asset. The valuation allowance serves to reduce the tax benefits recognized from the net deferred tax asset to an amount that is more likely than not to be realized based on the weight of all available evidence. The tax benefit of $8.7 million, net of the valuation allowance, for the year ended December 31, 2009 was due to various federal and state return-to-accrual adjustments.

Liquidity and Capital Resources

Our primary sources of liquidity and capital resources are cash flow generated from operations, borrowings under our senior credit facility, the issuance of equity and debt securities, and the monetization of non-core assets. As described in Item 1 "Business — Recent Developments," we could also realize proceeds from the proposed royalty trust offering. Our primary uses of capital are expenditures related to our oil and natural gas properties and other fixed assets, the acquisition of oil and natural gas properties, the repayment of amounts outstanding on our senior credit facility, the payment of dividends on our outstanding convertible perpetual preferred stock and interest payments on our outstanding debt. We maintain access to funds that may be needed to meet capital funding requirements through our senior credit facility.

Working Capital

Our working capital balance fluctuates as a result of the timing and amount of borrowings or repayments under our credit arrangements and changes in the fair value of our outstanding commodity derivative instruments. Absent any significant effects from our commodity derivative instruments, we typically have a working capital deficit or a relatively small amount of positive working capital because our capital spending generally has exceeded our cash flows from operations and we generally use excess cash to pay down borrowings outstanding under our credit arrangements.

At December 31, 2010, we had a working capital deficit of $368.9 million compared to a surplus of $30.4 million at December 31, 2009. Current assets decreased $80.4 million at December 31, 2010, compared to current assets at December 31, 2009, primarily due to a $101.0 million decrease in our current derivative contract assets resulting from the settlement of commodity derivative contracts during 2010. Current liabilities increased $318.9 million due, in part, to a $173.0 million increase in accounts payable and accrued expenses due to increased drilling activity. Our current derivative contract liabilities increased $96.3 million due to increased liability positions on our oil price swaps and our natural gas basis swaps. Additionally, we recorded a provision of $105.0 million for the estimated contract loss related to construction of the Century Plant. The contract loss provision was net of accumulated costs on the contract and included in current liabilities.

Cash Flows

Our cash flows for the years ended December 31, 2010, 2009 and 2008 are presented in the following table and discussed below:

	Year Ended December 31,		
	2010	2009	2008
		(In thousands)	
Cash flows			
Cash flows provided by operating activities	$ 390,128	$ 311,559	$ 579,189
Cash flows used in investing activities	(962,753)	(1,247,059)	(1,909,443)
Cash flows provided by financing activities	570,627	942,725	1,267,755
Net (decrease) increase in cash and cash equivalents	$ (1,998)	$ 7,225	$ (62,499)

Cash Flows from Operating Activities

Our operating cash flow is mainly influenced by the prices we receive for our oil and natural gas production; the quantity of oil and natural gas we produce; the demand for our drilling rigs and oil field services and the rates we are able to charge for these services; and the margins we obtain from our natural gas and CO_2 gathering and treating contracts.

Net cash provided by operating activities for the years ended December 31, 2010 and 2009 was $390.1 million and $311.6 million, respectively. The increase in cash provided by operating activities in 2010 compared to 2009 was primarily due to a 48.1% increase in the combined average prices we received for our oil and natural gas production, and increased oil production resulting from the properties acquired from Forest and Arena and a focus on increased oil drilling in 2010.

Net cash provided by operating activities for the years ended December 31, 2009 and 2008 was $311.6 million and $579.2 million, respectively. The decrease in cash provided by operating activities from 2008 to 2009 is primarily due to our $454.0 million decrease in revenues as a result of the 51.6% decrease in prices received on our production during 2009. These decreases were partially offset by increases in realized gains on our commodity derivative contracts settled during 2009.

Cash Flows from Investing Activities

We dedicate and expect to continue to dedicate a substantial portion of our capital expenditure program toward the development, production and acquisition of oil and natural gas reserves. These capital expenditures are necessary to offset inherent declines in production and proven reserves, which is typical in the capital-intensive oil and natural gas industry.

Cash flows used in investing activities decreased to $962.8 million in the year ended December 31, 2010 from $1,247.1 million in 2009 primarily due to the use of equity to fund the majority of the Arena Acquisition in July 2010 rather than cash, which was used to purchase the properties acquired from Forest in 2009. This was partially offset by increased capital expenditures during 2010.

Cash flows used in investing activities decreased to $1,247.1 million during 2009 from $1,909.4 million in 2008 due to the reduction in our capital expenditure program in 2009. Capital expenditures, excluding acquisitions, decreased $1,532.7 million to $645.1 million for the year ended December 31, 2009 compared to $2,177.8 million for the same period in 2008 primarily due to our decreased drilling activities. The decrease in cash outflows for capital expenditures was partially offset by the Forest Acquisition which resulted in $795.1 million of cash outflows in 2009. Cash outflows from capital expenditures in 2009 were partially offset by approximately $255.0 million in combined net proceeds from the sale of our gathering and compression assets located in the Piñon Field and our deep drilling rights in East Texas. Cash outflows from capital expenditures in 2008 were partially offset by approximately $147.2 million in proceeds from the sale of our assets located in the Piceance Basin of Colorado.

Capital Expenditures. Our capital expenditures, on an accrual basis, by segment are summarized below:

	Year Ended December 31,		
	2010	2009	2008
		(In thousands)	
Capital expenditures			
Exploration and production	$1,027,933	$ 555,809	$1,909,078
Drilling and oil field services	31,658	4,090	52,869
Midstream gas services	48,401	52,425	160,460
Other	21,661	32,818	55,440
Capital expenditures, excluding acquisitions	1,129,653	645,142	2,177,847
Acquisitions(1)	138,428	795,074	—
Total	$1,268,081	$1,440,216	$2,177,847

(1) 2010 acquisition expenditures include only the cash portion of the Arena Acquisition.

Cash Flows from Financing Activities

Our financing activities provided $570.6 million in cash for the year ended December 31, 2010 compared to $942.7 million in 2009. Cash provided by financing activities during the year ended December 31, 2010 was primarily comprised of $328.0 million of net borrowings, representing borrowings under our senior credit facility reduced by payments on our debt and $290.7 million of net proceeds from the issuance of 3,000,000 shares of our 7.0% convertible perpetual preferred stock, offset slightly by the payment of dividends on our 8.5% convertible perpetual preferred stock and our 6.0% convertible perpetual preferred stock and debt issuance costs. Cash provided by financing activities during the year ended December 31, 2009 was generated primarily by the private placements of an aggregate of 4,650,000 shares of our convertible perpetual preferred stock and the registered underwritten offering of 40,080,000 shares common stock that provided combined proceeds of approximately $768.0 million, the majority of which were used to pay down amounts outstanding under the senior credit facility.

Our financing activities provided $942.7 million in cash for the year ended December 31, 2009 compared to $1,267.8 million for the year ended December 31, 2008. Proceeds from borrowings were $2,619.6 million for the year ended December 31, 2009 compared to $3,252.2 million for 2008, as a result of lower borrowings during 2009 under our senior credit facility. We repaid borrowings of approximately $2,417.0 million during 2009, leaving net borrowings of approximately $202.6 million for the year. During 2009, we completed registered underwritten offerings of an aggregate of 40,080,000 shares of our common stock for net proceeds of approximately $324.8 million. Also in 2009, we completed private placements of an aggregate of 4,650,000 shares of our convertible perpetual preferred stock for net proceeds of approximately $443.2 million.

Indebtedness

Senior Credit Facility. The amount we may borrow under our senior credit facility is limited to a borrowing base, which is currently $850.0 million, and is subject to periodic redeterminations. The borrowing base is determined based upon the discounted present value of future cash flows attributable to our proved reserves. Because the value of our proved reserves is a key factor in determining the amount of the borrowing base, changing commodity prices and our success in developing reserves may affect the borrowing base. Outstanding letters of credit affect the availability under the senior credit facility on a dollar-for-dollar basis.

The senior credit facility contains various covenants that limit the ability of us and certain of our subsidiaries 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 the ability of us and certain of our subsidiaries to incur additional indebtedness with certain exceptions. The senior credit facility also contains financial covenants, including maintaining agreed levels for the (i) ratio of total funded debt to EBITDAX (as defined in the senior credit facility), which may not exceed 4.5:1.0 at each quarter end calculated using the last four completed fiscal quarters and (ii) ratio of current assets to current liabilities, which must be at least 1.0:1.0 at each quarter end. In the current ratio calculation (as defined in the senior credit facility) any amounts available to be drawn under the senior credit facility are included in current assets, and unrealized assets and liabilities resulting from mark-to-market adjustments on the Company's derivative contracts are disregarded.

In April 2010, we amended and restated our $1.75 billion senior credit facility, extending the maturity date to April 15, 2014 from November 2011 and affirming the borrowing base at $850.0 million. The senior credit facility received commitments from 27 participating lender institutions, three of which were new to the bank group. The largest commitment held by any individual lender is 5.9%. In conjunction with the April 2010 amendment and restatement, (a) we and the lenders agreed to eliminate the covenant that had required us to maintain the ratio of EBITDAX to interest expense plus current maturities of long-term debt at specified levels and (b) our ability to make investments was increased from the previous terms. In October 2010, the senior credit facility was further amended and, effective with this amendment, the ratio of our secured indebtedness to EBITDAX may not exceed 2.0:1.0 at each quarter end.

On February 23, 2011, our senior credit facility was amended to, among other things, (a) exclude from the calculation of Consolidated Net Income the net income (or loss) of a Royalty Trust, except to the extent of cash distributions received by us, (b) establish that an investment in a Royalty Trust and dispositions to, and of interests in, Royalty Trusts are permitted, (c) clarify that a Royalty Trust is not a Subsidiary, (d) allow us to net against our calculation of Consolidated Funded Indebtedness cash balances exceeding $10.0 million in the event no loans are outstanding under the senior credit facility at that time, and (e) establish that, for any fiscal quarter prior to March 31, 2012, if our Senior Secured Leverage Ratio is less than 1.5:1.0 then our Consolidated Leverage Ratio is negated. Terms capitalized in the preceding sentence have the meaning given to them in the senior credit facility, as amended. We remain in compliance with all debt covenants and the next redetermination of the borrowing base is scheduled to occur in the second quarter of 2011.

Long-term debt. Long-term obligations under outstanding debt agreements consist of the following at December 31, 2010 (in thousands):

Senior credit facility	$ 340,000
Other notes payable	23,322
Senior Floating Rate Notes due 2014	350,000
8.625% Senior Notes due 2015	650,000
9.875% Senior Notes due 2016, net of $12,793 discount	352,707
8.0% Senior Notes due 2018	750,000
8.75% Senior Notes due 2020, net of $6,943 discount	443,057
Total debt	$2,909,086

The indentures governing the senior notes referred to above contain limitations on the incurrence of indebtedness, payment of dividends, investments, asset sales, certain asset purchases, transactions with related parties and consolidations or mergers.

For more information about the senior credit facility, the senior notes and our other long-term debt obligations, see Note 14 to the consolidated financial statements included in Item 8 of this report.

Outlook

For 2011, we have budgeted $1.3 billion for capital expenditures. The majority of our capital expenditures are discretionary and could be curtailed if our cash flows decline from expected levels or we are unable to obtain capital on attractive terms. We may increase or decrease planned capital expenditures depending on oil and natural gas prices, asset sales and the availability of capital through the issuance of additional equity or long-term debt.

Our revenue, profitability and future growth are substantially dependent upon the prevailing and future prices for oil and natural gas, each of which depend on numerous factors beyond our control such as economic conditions, regulatory developments and competition from other energy sources. The energy markets and oil and natural gas prices historically have been volatile and may be subject to significant fluctuations in the future. Our derivative arrangements serve to mitigate a portion of the effect of this price volatility on our cash flows, and while derivative contracts for the majority of expected 2011 and 2012 oil production are in place, fixed price swap contracts are in place for only a portion of expected 2011 and 2012 natural gas production and 2013 oil production and no fixed price swap contracts are in place for our natural gas production beyond 2012 or oil production beyond 2013. See Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" for additional information regarding our derivative contracts. In addition, we have and will continue to need to incur capital expenditures in order to achieve production targets contained in certain gathering and treating arrangements. We are dependent on the availability of borrowings under our senior credit facility, along with cash flows from operating activities and proceeds from planned asset sales, to fund those capital expenditures. Based on anticipated oil and natural gas prices, availability under our senior credit facility, potential access to the capital markets and anticipated proceeds from the sales or other strategic monetizations of assets, we expect to be able to fund our planned capital expenditures budget, debt service requirements and working capital needs for the next 12 months. However, a substantial or extended decline in oil or natural gas prices could have a material adverse effect on our financial position, results of operations, cash flows and quantities of oil and natural gas reserves that may be economically produced, which could adversely impact our ability to comply with the financial covenants under our senior credit facility, which in turn would limit further borrowings to fund capital expenditures. We may choose to refinance borrowings outstanding under the facility by issuing long-term debt or equity in the public or private markets, or both. We have the ability to reduce our capital expenditures budget if cash flows are not available.

As of December 31, 2010, our cash and cash equivalents were $5.9 million and we had approximately $2.9 billion in total debt outstanding with $340.0 million outstanding under our senior credit facility. As of December 31, 2010, we were in compliance with all of the covenants under all of our senior notes and our senior credit facility. As of February 22, 2011, our cash and cash equivalents were approximately $4.3 million, the balance outstanding under our senior credit facility was $382.0 million and we had $34.4 million outstanding in letters of credit.

Contractual Obligations

A summary of our contractual obligations as of December 31, 2010 is provided in the following table:

	Payments Due by Year						
	2011	2012	2013	2014	2015	After 2015	Total
				(In thousands)			
Long-term debt	$ 7,293	$ 1,051	$ 1,120	$691,191	$651,266	$1,576,901	$2,928,822
Interest on senior notes(1)	206,084	206,084	206,084	195,169	149,483	317,666	1,280,570
Firm transportation	20,075	20,130	16,973	11,315	11,315	33,976	113,784
Gas gathering and throughput agreements	43,087	52,121	51,942	50,354	42,153	225,678	465,335
Purchase commitment	12,410	12,444	10,336	—	—	—	35,190
Third-party drilling rig commitments(2)	19,034	—	—	—	—	—	19,034
Asset retirement obligations	25,360	3,944	154	5,101	993	84,325	119,877
Operating leases & other	9,585	3,971	2,364	112	27	8,334	24,393
Total	$342,928	$299,745	$288,973	$953,242	$855,237	$2,246,880	$4,987,005

(1) For the Senior Floating Rate Notes due 2014, interest rates as of December 31, 2010 were used.

(2) Drilling contracts with third-party drilling rig operators at specified day or footage rates. All of our drilling rig contracts contain operator performance conditions that allow for pricing adjustments or early termination for operator nonperformance.

Interest associated with borrowings under our senior credit facility have been excluded from the above table due to variability of both the amount borrowed and the applicable interest rate. The principal amount outstanding under the senior credit facility at December 31, 2010 was $340.0 million and has been included in the table. Amounts borrowed under the senior credit facility are due in 2014 and bore interest at a rate of 2.51% as of December 31, 2010.

We maintain deposits in bank trust and escrow accounts as required by BOEMR, surety bond underwriters, purchase agreements or other settlement agreements to satisfy our eventual responsibility to plug and abandon wells and remove structures when certain offshore fields are no longer in use.

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 of America. 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 "Note 1 — Summary of Significant Accounting Policies" to the consolidated financial statements included in Item 8 of this report for a discussion of our significant accounting policies.

Proved Reserves. Approximately 96.5% of our reserves are estimated on an annual basis by independent petroleum engineers. Estimates of proved reserves are based on the quantities of oil and natural gas that 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. Estimating reserves 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, 2010, 2009 and 2008, we revised our proved reserves from prior years' reports by approximately 327.2 MMBoe or 1,963.1 Bcfe, (198.7) MMBoe or (1,191.9) Bcfe and 75.4 MMBoe or 452.6 Bcfe, respectively, due to market prices during or at the end of the applicable period or production performance indicating more (or less) reserves in place or larger (or smaller) reservoir size than initially estimated or additional proved reserve bookings within the original field boundaries. 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 depreciation and depletion expenses.

Method of Accounting for Oil and Natural Gas Properties. The accounting for our business is subject to special accounting rules that are unique to the oil and natural gas industry. There are two allowable methods of accounting for oil and natural gas business activities: the successful efforts method and the full cost method. We follow the full cost method of accounting. All direct costs and certain indirect costs associated with the acquisition, exploration and development of oil and natural gas properties are capitalized. Exploration and development costs include dry well costs, geological and geophysical costs, direct overhead related to exploration and development activities and other costs incurred for the purpose of finding oil and natural gas reserves. Amortization of oil and natural gas properties is provided using the unit-of-production method based on estimated proved oil and natural gas reserves. Sales and abandonments of oil and natural gas 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 oil and natural gas reserves. A significant alteration would not ordinarily be expected to occur upon the sale of reserves involving less than 25% of the reserve quantities of a cost center.

Under the successful efforts method, geological and geophysical costs and costs of carrying and retaining undeveloped properties are charged to expense as incurred. Costs of drilling exploratory wells that do not result in proved reserves are charged to expense. Depreciation, depletion and impairment of oil and natural gas properties are generally calculated on a well by well, lease or field basis versus the aggregated "full cost" pool basis. Additionally, gain or loss is generally recognized on all sales of oil and natural gas properties under the successful efforts method. As a result, our financial statements will differ from companies that apply the successful efforts method since we will generally reflect a higher level of capitalized costs as well as a higher oil and natural gas depreciation, depletion and amortization rate, and we will not have exploration expenses that successful efforts companies frequently have.

In accordance with full cost accounting rules, capitalized costs are subject to a limitation. The capitalized cost of oil and natural gas 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 oil and natural gas reserves, discounted at 10% per annum, plus the lower of cost or fair value of unproved properties, plus estimated salvage value, less related tax effects (the "ceiling limitation"). Beginning with the December 31, 2009 calculation, we began calculating our full cost ceiling limitation using the 12-month average oil and natural gas prices for the most recent 12 months as of the balance sheet date and adjusted for "basis" or location differential, held constant over the life of the reserves. Prior to December 31, 2009, the full cost ceiling limitation calculation required companies to use oil and natural gas prices on the last day of the period. If capitalized costs exceed the ceiling limitation, the excess must be charged to expense. Once incurred, a write-down is not reversible at a later date. During the year ended December 31, 2009, total capitalized costs of our oil and natural gas properties exceeded our ceiling limitation resulting in a non-cash ceiling impairment of $1,693.3 million, $388.9 million of which was incurred in the fourth quarter under the current SEC rule and $1,304.4 million of which was incurred in the first quarter under the rules in effect at the time. For the year ended December 31, 2008, total capitalized costs of our oil and natural gas properties exceeded our ceiling limitation resulting in a non-cash ceiling impairment of $1,855.0 million calculated under the previous rules. There were no full cost ceiling impairments recorded during 2010.

Unevaluated Properties. The balance of unevaluated properties consists 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 six-year period from the date of acquisition, contingent on our capital expenditures and drilling program.

Asset Retirement Obligations. Asset retirement obligations represent the estimate of fair value to plug, abandon and remediate our oil and natural gas properties at the end of their productive lives, in accordance with applicable state laws. 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 Natural Gas Balancing. Oil and natural gas revenues are recorded when title of sold oil and natural gas production 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 and footage drilling contracts as the services are performed, since we do not bear the risk of completion of the well.

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 typically range from 30 days to two years.

Revenue from sales of CO_2 is recognized when the product is delivered to the customer.

Property, Plant and Equipment, Net. Other capitalized costs, including drilling equipment, natural gas gathering and treating 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 reflected in operations.

Income Taxes. Deferred income taxes are recorded for temporary differences between financial statement and income tax basis. Temporary differences are differences between the amounts of assets and liabilities reported for financial statement purposes and their tax basis. 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.

As of December 31, 2010, we continue to have a full valuation allowance against our net deferred tax asset. Our deferred tax position changed from a net deferred tax liability as of December 31, 2007 to a net deferred tax asset as of December 31, 2008 due to the recording of a full cost ceiling impairment of $1,855.0 million. The valuation allowance serves to reduce the tax benefits recognized from the net deferred tax asset to an amount that is more likely than not to be realized based on the weight of all available evidence. Net deferred tax liabilities recorded as a result of the Arena Acquisition reduced our existing net deferred tax asset position, allowing a corresponding reduction in the valuation allowance.

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

We recognize all of our derivative contracts as either assets or liabilities at fair value. We determine fair value of our derivative contracts primarily based upon quotes obtained from the counterparties to the contracts. The changes in the fair value (i.e., gains or losses) of a derivative contract is included in earnings unless the derivative contract has been designated and qualifies as part of a hedging relationship, and further, on the type of hedging relationship. None of our derivatives was designated as hedging instruments during 2010, 2009 and 2008.

Goodwill. Goodwill represents the excess of the consideration paid over the fair value of identifiable net assets acquired in the Arena Acquisition. Goodwill is not amortized, but rather tested annually for impairment. We will evaluate the carrying value of goodwill as of July 1 of each year and between annual evaluations if events occur or circumstances change that would more likely than not reduce the fair value of the reporting unit below its carrying amount. We have not identified any such events as of December 31, 2010 that required an impairment test prior to our annual goodwill evaluation.

New Accounting Pronouncements

For a discussion of recently adopted accounting standards, see Note 1 to our consolidated financial statements included in Item 8 of this report.

Item 7A. *Quantitative and Qualitative Disclosures about Market Risk*

General

The discussion in this section provides information about the financial instruments we use to manage commodity prices and interest rate volatility. All contracts are settled in cash and do not require the actual delivery of a commodity at settlement.

Commodity Price Risk. Our most significant market risk relates to the prices we receive for our oil and natural gas production. Due to the historical volatility of these commodities, we periodically have entered into, and expect in the future to enter into, derivative arrangements for the purpose of reducing the variability of oil and natural gas prices we receive for our production. From time to time, we enter into commodity pricing derivative contracts for a portion of our anticipated production volumes depending upon management's view of opportunities under the then prevailing current market conditions. Our senior credit agreement limits our ability to enter into derivative transactions to 85% of expected production volumes from estimated proved reserves. We do not intend to enter into derivative contracts that would exceed our expected production volumes for the period covered by the derivative arrangement. Future credit agreements could require a minimum level of commodity price hedging.

The use of derivative contracts involves the risk that the counterparties will be unable to meet their obligations under the contracts. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty. As of December 31, 2010, we had 19 approved derivative counterparties, all of which are lenders under our senior credit facility. We currently have derivative contracts outstanding with 15 of these counterparties.

We use, and may continue to use, a variety of commodity-based derivative contracts, including fixed-price swaps and basis protection swaps. Our oil fixed price swap transactions are settled based upon the average daily prices for the calendar month of the contract period. Our natural gas fixed price swap transactions are settled based upon New York Mercantile Exchange prices, and our natural gas basis protection swap transactions are settled based upon the index price of natural gas at the Waha hub, a West Texas gas marketing and delivery center, and the Houston Ship Channel. Settlement for oil derivative contracts occurs in the succeeding month and natural gas derivative contracts are settled in the production month.

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 reflects changes in oil and natural gas prices. We establish fair value of our derivative contracts by price quotations obtained from counterparties to the derivative contracts. Changes in fair values of our derivative contracts 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 the fair value of our commodity derivative contracts. Changes in fair value are principally measured based on period-end prices compared to the contract price.

See Note 16 to our consolidated financial statements included in Item 8 of this report for a summary of our open oil and natural gas commodity derivative contracts.

The following table summarizes the cash settlements and valuation gains and losses on our commodity derivative contracts for the years ended December 31, 2010, 2009 and 2008 (in thousands):

Oil and Natural Gas Derivatives	Year Ended December 31, 2010	2009	2008
Realized (gain) loss(1)	$(224,337)	$(348,022)	$ 12,981
Unrealized loss (gain)	275,209	200,495	(224,420)
Loss (gain) on commodity derivative contracts	$ 50,872	$(147,527)	$(211,439)

(1) Includes $114.4 million of realized gains for the year ended December 31, 2010, related to settlements of commodity derivative contracts with contractual maturities after the quarterly period in which they were settled. There were no commodity derivative contracts settled prior to the contractual maturity during 2009 or 2008.

Credit Risk. We minimize the volatility of our liquidity by entering into derivative contracts that enable us to mitigate a portion of our exposure to oil and natural gas prices and interest rate volatility. We periodically review the credit quality of each counterparty to our derivative contracts and the level of overall financial exposure we have to each counterparty to limit our credit risk exposure with respect to these contracts. Additionally, we apply a credit default risk rating factor for our counterparties in determining the fair value of our derivative contracts. The counterparties for all of our derivative transactions have an "investment grade" credit rating.

Our ability to fund our capital expenditure budget is partially dependent upon the availability of funds under our senior credit facility. In order to mitigate the credit risk associated with individual financial institutions committed to participate in our senior credit facility, our bank group currently consists of 27 financial institutions with commitments ranging from 0.57% to 5.9%.

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 to (i) changes in market interest rates reflected in the fair value of the debt and (ii) 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.

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 agreement. We have entered into two $350.0 million notional interest rate swap agreements to fix the variable interest rate on the Senior Floating Rate Notes through April 1, 2013. The first interest rate swap agreement fixes the rate on the Senior Floating Rate Notes at an annual rate of 6.26% through April 1, 2011. The second interest rate swap agreement fixes the rate on the Senior Floating Rate Notes at an annual rate of 6.69% for the period from April 1, 2011 to April 1, 2013. The two interest rate swaps effectively serve to fix the variable interest rate on our Senior Floating Rate Notes for the majority of the term of these notes. These swaps have not been designated as hedges.

Our interest rate swaps reduce our market risk on our Senior Floating Rate Notes. We use sensitivity analyses to determine the impact that market risk exposures could have on our variable interest rate borrowings if not for our interest rate swaps. Based on the $350.0 million outstanding balance of our Senior Floating Rate Notes at December 31, 2010, a one percent change in the applicable rates, with all other variables held constant, would have resulted in a change in our interest expense of approximately $3.5 million for the year ended December 31, 2010.

The following table summarizes the cash settlements and valuation gains and losses on our interest rate swaps for the years ended December 31, 2010, 2009 and 2008 (in thousands):

	Year Ended December 31,		
Interest Rate Swaps	**2010**	**2009**	**2008**
Realized loss (gain)	$ 8,145	$6,229	$(1,304)
Unrealized loss (gain)	8,395	(446)	8,745
Loss on interest rate swaps	$16,540	$5,783	$ 7,441

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***

Disclosure Controls and Procedures. Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we performed an evaluation 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 annual report. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2010 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 SEC, and such information is accumulated and communicated to management, as appropriate to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting and Report of Independent Registered Public Accounting Firm. The information required to be furnished pursuant to this item is set forth under the captions "Management's Report on Internal Control over Financial Reporting" and "Report of Independent Registered Public Accounting Firm" in Item 8 of this report.

Changes in Internal Control over Financial Reporting. There were no changes in our internal control over financial reporting during the quarter ended December 31, 2010 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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 the following sections of our definitive proxy statement, which will be filed no later than May 2, 2011: "Director Biographical Information," "Executive Officers," "Compliance with Section 16(a) of the Exchange Act" and "Corporate Governance Matters."

Item 11. ***Executive Compensation***

The information required by this item is incorporated herein by reference to the following sections of our definitive proxy statement, which will be filed no later than May 2, 2011: "Director Compensation," "Outstanding Equity Awards" and "Executive Officers and Compensation."

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 the following sections of our definitive proxy statement, which will be filed no later than May 2, 2011: "Equity Compensation Plan Information" and "Security Ownership of Certain Beneficial Owners and Management."

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

The information required by this item is incorporated herein by reference to the following sections of our definitive proxy statement, which will be filed no later than May 2, 2011: "Related Party Transactions" and "Corporate Governance Matters."

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

The information required by this item is incorporated herein by reference to the section captioned "Ratification of Selection of Independent Registered Public Accounting Firm" in our definitive proxy statement, which will be filed no later than May 2, 2011.

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*

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) under the Exchange Act. Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

Based on our evaluation on criteria for effective internal control over financial reporting described in *Internal Control — Integrated Framework*, our management concluded, that as of December 31, 2010, our internal control over financial reporting was effective.

The effectiveness of our internal control over financial reporting as of December 31, 2010 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report that follows.

/s/ TOM L. WARD	/s/ JAMES D. BENNETT
Tom L. Ward Chief Executive Officer	James D. Bennett Executive Vice President and Chief Financial Officer

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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying "Management's Report on Internal Control Over Financial Reporting." Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 1 to the consolidated financial statements, effective December 31, 2009, the Company has changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.

A company's 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 for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Houston, Texas
February 28, 2011

SandRidge Energy, Inc., and Subsidiaries
Consolidated Balance Sheets

	December 31, 2010	December 31, 2009
	(In thousands)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 5,863	$ 7,861
Accounts receivable, net	146,118	105,476
Derivative contracts	5,028	105,994
Inventories	3,945	3,707
Costs in excess of billings	—	12,346
Other current assets	14,636	20,580
Total current assets	175,590	255,964
Oil and natural gas properties, using full cost method of accounting		
Proved	8,159,924	5,913,408
Unproved	547,953	281,811
Less: accumulated depreciation, depletion and impairment	(4,483,736)	(4,223,437)
	4,224,141	1,971,782
Other property, plant and equipment, net	509,724	461,861
Restricted deposits	27,886	32,894
Goodwill	234,356	—
Other assets	59,751	57,816
Total assets	$ 5,231,448	$ 2,780,317
LIABILITIES AND EQUITY		
Current liabilities		
Current maturities of long-term debt	$ 7,293	$ 12,003
Accounts payable and accrued expenses	376,922	203,908
Billings and estimated contract loss in excess of costs incurred	31,474	—
Derivative contracts	103,409	7,080
Asset retirement obligation	25,360	2,553
Total current liabilities	544,458	225,544
Long-term debt	2,901,793	2,566,935
Other long-term obligations	19,024	14,099
Derivative contracts	124,173	61,060
Asset retirement obligation	94,517	108,584
Total liabilities	3,683,965	2,976,222
Commitments and contingencies (Note 20)		
Equity		
SandRidge Energy, Inc. stockholders' equity		
Preferred stock, $0.001 par value, 50,000 shares authorized		
8.5% Convertible perpetual preferred stock; 2,650 shares issued and outstanding at December 31, 2010 and December 31, 2009; aggregate liquidation preference of $265,000	3	3
6.0% Convertible perpetual preferred stock; 2,000 shares issued and outstanding at December 31, 2010 and December 31, 2009; aggregate liquidation preference of $200,000	2	2
7.0% Convertible perpetual preferred stock; 3,000 shares issued and outstanding at December 31, 2010; aggregate liquidation preference of $300,000	3	—
Common stock, $0.001 par value, 800,000 and 400,000 shares authorized at December 31, 2010 and December 31, 2009, respectively; 406,830 issued and 406,360 outstanding at December 31, 2010 and 210,581 issued and 208,715 outstanding at December 31, 2009	398	203
Additional paid-in capital	4,528,912	2,961,613
Treasury stock, at cost	(3,547)	(25,079)
Accumulated deficit	(2,989,576)	(3,142,699)
Total SandRidge Energy, Inc. stockholders' equity (deficit)	1,536,195	(205,957)
Noncontrolling interest	11,288	10,052
Total equity (deficit)	1,547,483	(195,905)
Total liabilities and equity	$ 5,231,448	$ 2,780,317

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

SandRidge Energy, Inc., and Subsidiaries
Consolidated Statements of Operations

	Years Ended December 31,		
	2010	2009	2008
	(In thousands, except per share amounts)		
Revenues			
Oil and natural gas	$ 774,763	$ 454,705	$ 908,689
Drilling and services	28,543	23,586	46,855
Midstream and marketing	100,118	86,028	207,602
Other	28,312	26,725	18,668
Total revenues	931,736	591,044	1,181,814
Expenses			
Production	237,863	169,880	159,545
Production taxes	29,170	4,010	30,594
Drilling and services	22,368	28,380	22,872
Midstream and marketing	90,149	80,608	189,428
Depreciation and depletion — oil and natural gas	275,335	176,027	290,917
Depreciation and amortization — other	50,776	50,865	70,448
Impairment	—	1,707,150	1,867,497
General and administrative	179,565	100,256	109,372
Loss (gain) on derivative contracts	50,872	(147,527)	(211,439)
Loss (gain) on sale of assets	2,424	26,419	(9,273)
Total expenses	938,522	2,196,068	2,519,961
Loss from operations	(6,786)	(1,605,024)	(1,338,147)
Other income (expense)			
Interest income	296	375	3,569
Interest expense	(247,738)	(185,691)	(147,027)
Income from equity investments	—	1,020	1,398
Other income, net	2,558	7,272	1,454
Total other expense	(244,884)	(177,024)	(140,606)
Loss before income taxes	(251,670)	(1,782,048)	(1,478,753)
Income tax benefit	(446,680)	(8,716)	(38,328)
Net income (loss)	195,010	(1,773,332)	(1,440,425)
Less: net income attributable to noncontrolling interest	4,445	2,258	855
Net income (loss) attributable to SandRidge Energy, Inc.	190,565	(1,775,590)	(1,441,280)
Preferred stock dividends and accretion	37,442	8,813	16,232
Income available (loss applicable) to SandRidge Energy, Inc. common stockholders	$ 153,123	$(1,784,403)	$(1,457,512)
Earnings (loss) per share			
Basic	$ 0.52	$ (10.20)	$ (9.36)
Diluted	$ 0.52	$ (10.20)	$ (9.36)
Weighted average number of common shares outstanding			
Basic	291,869	175,005	155,619
Diluted	315,349	175,005	155,619

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

SandRidge Energy, Inc., and Subsidiaries
Consolidated Statements of Changes in Stockholders' Equity

	Convertible Perpetual Preferred Stock		Common Stock		Additional Paid-In Capital	Treasury Stock	Retained Earnings (Accumulated Deficit)	Noncontrolling Interest	Total
	Shares	Amount	Shares	Amount					
	(In thousands)								
Balance, December 31, 2007	—	$—	141,843	$140	$1,686,113	$(18,578)	$ 99,216	$ 4,672	$ 1,771,563
Distributions to noncontrolling interest owners	—	—	—	—	—	—	—	(5,497)	(5,497)
Accretion on redeemable convertible preferred stock	—	—	—	—	—	—	(7,636)	—	(7,636)
Conversion of redeemable convertible preferred stock	—	—	22,276	23	458,328	—	—	—	458,351
Purchase of treasury stock	—	—	—	—	—	(3,553)	—	—	(3,553)
Common stock issued under retirement plans	—	—	211	—	3,167	2,799	—	—	5,966
Stock-based compensation	—	—	—	—	18,784	—	—	—	18,784
Stock-based compensation excess tax benefit	—	—	—	—	4,594	—	—	—	4,594
Issuance of restricted stock awards, net of cancellations	—	—	1,716	—	—	—	—	—	—
Net (loss) income	—	—	—	—	—	—	(1,441,280)	855	(1,440,425)
Redeemable convertible preferred stock dividends	—	—	—	—	—	—	(8,596)	—	(8,596)
Balance, December 31, 2008	—	—	166,046	163	2,170,986	(19,332)	(1,358,296)	30	793,551
Distributions to noncontrolling interest owners	—	—	—	—	—	—	—	(26)	(26)
Consolidation of Grey Ranch Plant L.P.	—	—	—	—	—	—	—	7,790	7,790
Issuance of convertible perpetual preferred stock, net	4,650	5	—	—	443,205	—	—	—	443,210
Issuance of common stock	—	—	40,080	40	324,790	—	—	—	324,830
Purchase of treasury stock	—	—	—	—	—	(1,494)	—	—	(1,494)
Stock purchase — retirement plans	—	—	(373)	—	(602)	(4,253)	—	—	(4,855)
Stock-based compensation	—	—	—	—	27,098	—	—	—	27,098
Stock-based compensation excess tax benefit	—	—	—	—	(3,864)	—	—	—	(3,864)
Issuance of restricted stock awards, net of cancellations	—	—	2,962	—	—	—	—	—	—
Net (loss) income	—	—	—	—	—	—	(1,775,590)	2,258	(1,773,332)
Convertible perpetual preferred stock dividends	—	—	—	—	—	—	(8,813)	—	(8,813)
Balance, December 31, 2009	4,650	5	208,715	203	2,961,613	(25,079)	(3,142,699)	10,052	(195,905)
Distributions to noncontrolling interest owners	—	—	—	—	—	—	—	(3,515)	(3,515)
Contributions from noncontrolling interest owners	—	—	—	—	—	—	—	306	306
Issuance of common stock in acquisition	—	—	190,280	190	1,246,144	—	—	—	1,246,334
Issuance of convertible perpetual preferred stock, net	3,000	3	—	—	290,701	—	—	—	290,704
Stock issued under legal settlement	—	—	1,789	2	(1,835)	14,033	—	—	12,200
Purchase of treasury stock	—	—	—	—	—	(6,275)	—	—	(6,275)
Retirement of treasury stock	—	—	—	—	(11,268)	11,268	—	—	—
Stock purchase — retirement plans, net of distributions	—	—	(96)	—	2,327	2,506	—	—	4,833
Stock awards assumed in acquisition	—	—	—	—	2,152	—	—	—	2,152
Issuance of restricted stock awards, net of cancellations	—	—	5,672	3	(3)	—	—	—	—
Stock-based compensation	—	—	—	—	39,066	—	—	—	39,066
Stock-based compensation excess tax benefit	—	—	—	—	15	—	—	—	15
Net income	—	—	—	—	—	—	190,565	4,445	195,010
Convertible perpetual preferred stock dividends	—	—	—	—	—	—	(37,442)	—	(37,442)
Balance, December 31, 2010	7,650	$ 8	406,360	$398	$4,528,912	$ (3,547)	$(2,989,576)	$11,288	$ 1,547,483

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

SandRidge Energy, Inc., and Subsidiaries
Consolidated Statements of Cash Flows

	2010	2009	2008
		Years Ended December 31, (In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	$ 195,010	$(1,773,332)	$(1,440,425)
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Provision for doubtful accounts	129	214	1,748
Depreciation, depletion and amortization	326,111	226,892	361,365
Impairment	—	1,707,150	1,867,497
Debt issuance costs amortization	11,006	7,477	5,623
Discount amortization on long-term debt	2,153	990	—
Deferred income taxes	(447,500)	—	(47,530)
Unrealized loss (gain) on derivative contracts	283,604	200,049	(215,675)
Loss (gain) on sale of assets	2,424	26,419	(9,273)
Investment income	(460)	(51)	(402)
Income from equity investments	—	(1,020)	(1,398)
Stock-based compensation	37,681	22,793	18,784
Changes in operating assets and liabilities increasing (decreasing) cash			
Receivables	(11,480)	8,760	3,735
Inventories	(238)	61	307
Other current assets	8,079	47,317	(20,603)
Billings in excess of costs/costs in excess of billings	(61,180)	(26,490)	14,144
Other assets and liabilities, net	2,667	(26,937)	14,271
Accounts payable and accrued expenses	42,122	(108,733)	27,021
Net cash provided by operating activities	390,128	311,559	579,189
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures for property, plant and equipment	(1,044,371)	(715,205)	(2,058,415)
Acquisitions of assets, net of $39,518 and $0 cash received	(138,428)	(795,074)	—
Proceeds from sale of assets	204,951	263,220	158,781
Deposit received on pending asset sale	10,000	—	—
Contributions on equity investments	—	—	(1,528)
Loans to equity investees	—	—	(7,500)
Refunds of restricted deposits	5,095	—	—
Fundings of restricted deposits	—	—	(781)
Net cash used in investing activities	(962,753)	(1,247,059)	(1,909,443)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from borrowings	2,117,914	2,619,607	3,252,209
Repayments of borrowings	(1,789,919)	(2,416,975)	(1,944,542)
Dividends paid-preferred	(28,525)	—	(17,552)
Noncontrolling interest distributions	(3,515)	(26)	(5,497)
Noncontrolling interest contributions	306	—	—
Proceeds from issuance of common stock, net	—	324,830	—
Proceeds from issuance of convertible perpetual preferred stock, net	290,704	443,210	—
Stock-based compensation excess tax benefit	15	(3,864)	4,594
Purchase of treasury stock	(7,169)	(5,747)	(3,553)
Derivative settlements	3,356	—	—
Debt issuance costs	(12,540)	(18,310)	(17,904)
Net cash provided by financing activities	570,627	942,725	1,267,755
NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	(1,998)	7,225	(62,499)
CASH AND CASH EQUIVALENTS, beginning of year	7,861	636	63,135
CASH AND CASH EQUIVALENTS, end of year	$ 5,863	$ 7,861	$ 636
Supplemental Disclosure of Cash Flow Information			
Cash paid for interest	$ 211,377	$ 171,994	$ 131,183
Cash (received) paid for income taxes	(1,508)	2,908	2,191
Supplemental Disclosure of Noncash Investing and Financing Activities			
Change in accrued capital expenditures	$ 85,282	$ (70,063)	$ 119,432
Convertible perpetual preferred stock dividends payable	17,363	8,813	—
Adjustment to oil and natural gas properties for estimated contract loss	105,000	—	—
Common stock issued in connection with acquisition	1,246,334	—	—
Stock issued to satisfy settlement	12,200	—	—
Accretion on redeemable convertible preferred stock	—	—	7,636

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

SandRidge Energy, Inc., and Subsidiaries
Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

Nature of Business. SandRidge Energy, Inc. (including its subsidiaries, the "Company" or "SandRidge") is an independent oil and natural gas company concentrating on development and production activities related to the exploitation of its significant holdings in West Texas and the Mid-Continent area of Oklahoma and Kansas. The Company owns and operates other interests in the Mid-Continent, Cotton Valley Trend in East Texas, Gulf Coast and Gulf of Mexico. The Company also operates businesses that are complementary to its primary development and production activities. The Company owns and operates gas gathering and treating facilities, a gas marketing business, an oil field services business, including a drilling rig business, and tertiary oil recovery operations.

Principles of Consolidation. The consolidated financial statements include the accounts of SandRidge Energy, Inc. and its wholly owned or majority owned subsidiaries and variable interest entities for which the Company is the primary beneficiary. All significant intercompany accounts and transactions have been eliminated in consolidation.

Reclassifications. Certain reclassifications have been made to prior period financial statements to conform to the 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 exploration 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.

Risks and Uncertainties. The Company's revenue, profitability and future growth are substantially dependent upon the prevailing and future prices for oil and natural gas, each of which depends on numerous factors beyond the Company's control such as economic conditions, regulatory developments and competition from other energy sources. The energy markets and oil and natural gas prices historically have been volatile, and may be subject to significant fluctuations in the future. The Company's derivative arrangements serve to mitigate a portion of the effect of this price volatility on the Company's cash flows, and while derivative contracts for the majority of expected 2011 and 2012 oil production are in place, fixed price swap contracts are in place for only a portion of expected 2011 and 2012 natural gas production and 2013 oil production and no fixed price swap contracts are in place for the Company's natural gas production beyond 2012 or oil production beyond 2013. See Note 16 for the Company's open oil and natural gas commodity derivative contracts. The Company has incurred, and will have to continue to incur, capital expenditures to achieve production targets contained in certain gathering and treating arrangements. The Company is dependent on the availability of borrowings under its senior credit facility, along with cash flows from operating activities and the proceeds from planned asset sales, to fund those capital expenditures. Based on anticipated oil and natural gas prices, availability under its senior credit facility, potential access to the capital markets and anticipated proceeds from sales or other strategic monetizations of assets, the Company expects to be able to fund its planned capital expenditures budget, debt service requirements and working capital needs for the next 12 months. However, a substantial or extended decline in oil or 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, which could adversely impact the Company's ability to comply with the financial covenants under its senior credit facility, which in turn would limit further borrowings to fund capital expenditures. See Note 14 for discussion of the financial covenants in the senior credit facility.

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 as these instruments are readily convertible to known amounts of cash and bear insignificant risk of changes in value due to their short maturity period.

Accounts Receivable, Net. The Company has receivables for sales of oil and natural gas, as well as receivables related to the exploration and treating services for oil and natural gas. Management has established an allowance for doubtful accounts. The allowance is evaluated by management and is based on management's review of the collectability of the receivables in light of historical experience, the nature and volume of the receivables and other subjective factors. Accounts receivable are charged against the allowance, upon approval by management, when they are deemed uncollectible.

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.

Investments. Investments in affiliated companies are accounted for under the equity method in circumstances where the Company is deemed to exercise significant influence over the operating and investing policies of the investee but does not have control. Under the equity method, the Company recognizes its share of the investee's earnings in its consolidated statements of operations. Investments in affiliated companies not accounted for under the equity method are accounted for under the cost method. Investments in marketable equity securities have been designated as available for sale and measured at fair value pursuant to the fair value option which requires unrealized gains and losses be reported in earnings.

Fair Value of Financial Instruments. The Company's financial instruments, not otherwise recorded at fair value, consist primarily of cash, trade receivables, trade payables and long-term debt. The carrying value of cash, trade receivables and trade payables are considered to be representative of their respective fair values due to the short-term maturity of these instruments. See Note 3 for discussion of the fair value of the Company's derivative contracts and long-term debt.

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

The Company recognizes all of its derivative instruments as either assets or liabilities at fair value. The accounting for changes in the fair value (i.e., gains or losses) of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship, and further, on the type of hedging relationship. For those derivative instruments that are designated and qualify as hedging instruments, the Company designates the hedging instrument, based on the exposure being hedged, as either a fair value hedge or a cash flow hedge. For derivative instruments not designated as hedging instruments, the gain or loss is recognized in current earnings during the period of change. None of the Company's derivatives was designated as hedging instruments during 2010, 2009 and 2008.

Debt Issuance Costs. The Company amortizes debt issuance costs related to its long-term debt as interest expense over the scheduled maturity period of the debt. Unamortized debt issuance costs were $50.6 million as of December 31, 2010 and $49.1 million as of December 31, 2009. The Company includes these unamortized costs in other assets in its consolidated balance sheets.

Goodwill. Goodwill is the excess of the purchase price over the fair value of identifiable net assets acquired in the Arena Acquisition. The Company does not amortize goodwill, but will test it for impairment annually as of July 1, beginning in 2011, and between annual evaluations if events occur or circumstances change that would more likely than not reduce the fair value of the reporting unit below its carrying amount. The Company monitors the existence of potential impairment indicators throughout the year and has not identified any such events since the Arena Acquisition in July 2010.

Oil and Natural Gas Operations. The Company uses the full cost method to account for its oil and natural gas properties. Under full cost accounting, all costs directly associated with the acquisition, exploration and development of oil and natural gas 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 2010, the Company capitalized internal costs of $28.6 million to the full cost pool, including $5.6 million of stock compensation. During 2009, the Company capitalized internal costs of $22.3 million to the full cost pool, including $4.3 million of stock compensation. During 2008, the Company capitalized internal costs of $19.1 million to the full cost pool. The Company capitalized $0.3 million of interest to the full cost pool in 2010 related to properties that were made ready for production during 2010. There was no interest capitalized to the full cost pool in 2009 or 2008 and no stock compensation capitalized to the full cost pool in 2008.

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 the 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 amortizable 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, subjected to amortization. Sales and abandonments of oil and natural gas 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 oil and natural gas reserves. A significant alteration would not ordinarily be expected to occur upon the sale of reserves involving less than 25% of the reserve quantities of a cost center.

Under the full cost method of accounting, total capitalized costs of oil and natural gas 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 the related 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. See Note 7.

Effective December 31, 2009, the Company implemented Accounting Standards Update 2010-03 ("ASU 2010-03"), which aligned the oil and natural gas reserve estimation and disclosure requirements of ASC Topic 932, Extractive Industries — Oil and Gas, with the requirements in the SEC's final rule, *Modernization of the Oil and Gas Reporting Requirements*. Pursuant to ASU 2010-03, the ceiling limitation calculation was prepared using a 12-month oil and natural gas average price, as adjusted for basis or location differentials using a 12-month average, held constant over the life of the reserves ("net wellhead prices") for all quarters in 2010 and the fourth quarter of 2009. Per the requirements in place prior to December 31, 2009, the ceiling limitation calculation was prepared using oil and natural gas prices in effect as of the balance sheet date, as adjusted for basis or location differentials as of the balance sheet date, held constant over the life of the reserves, which was used for the first three quarters of 2009 and all quarters in 2008. If applicable, these net wellhead prices would be further adjusted to include the effects of any fixed price arrangements for the sale of oil and natural gas. The Company may, from time-to-time, use derivative financial instruments to hedge against the volatility of oil and 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 and has therefore not included its derivative contracts in estimating future cash flows. 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 limitation calculation.

The costs associated with unproved properties, initially excluded from the amortization base, 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 wells 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 various factors, including, but not limited to, the following: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; assignment of proved reserves; and 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 become subject to amortization.

Property, Plant and Equipment, Net. Other capitalized costs, including drilling equipment, natural gas gathering and treating 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 such 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 considered 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 considered impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value.

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

Asset Retirement Obligation. The Company owns oil and natural gas properties that require expenditures to plug and abandon the wells when the oil and natural gas reserves in the wells are depleted. These expenditures are recorded in the period in which the liability is incurred (at the time the wells are drilled or acquired). Asset retirement obligations are recorded as a liability at their estimated present value at the asset's inception, with the offsetting increase to property cost. Periodic accretion expense of the estimated liability is recorded in the consolidated 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 federal and state laws. The Company determines 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. The following table shows the activity of the asset retirement obligation for the years ended December 31 (in thousands).

	2010	2009	2008
Asset retirement obligation, January 1	$111,137	$ 84,772	$58,580
Liability incurred upon acquiring and drilling wells	17,347	14,537	5,707
Revisions in estimated cash flows	(17,017)	10,831	15,976
Liability settled in current period	(1,011)	(6,111)	(764)
Accretion of discount expense	9,421	7,108	5,273
Asset retirement obligation, December 31	119,877	111,137	84,772
Less: current portion	(25,360)	(2,553)	(275)
Asset retirement obligation, net of current	$ 94,517	$108,584	$84,497

The revisions in estimated cash flows for the year ended December 31, 2010 were primarily due to lengthening reserve lives based on higher oil and natural gas prices used to determine reserves relative to prices at the beginning of 2010. At December 31, 2010, asset retirement obligations of $21.8 million related to an offshore platform were moved to current, due to its anticipated plugging and abandonment in 2011. For the years ended December 31, 2009 and 2008, revisions in estimated cash flows were primarily due to shortening reserve lives based on lower oil and natural gas prices used to determine reserves relative to respective beginning of year prices. Also, due to hurricane damage, certain non-operated offshore platforms were plugged and abandoned during 2009 in advance of anticipated timelines.

Revenue Recognition and Natural Gas Balancing. Oil and natural gas revenues are recorded when title of sold oil and natural gas production 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 natural gas properties with insufficient proved reserves of $2.1 million and $1.9 million at December 31, 2010 and 2009, respectively. The Company includes the gas imbalance positions in other long-term obligations in its consolidated balance sheet. See Note 15.

The Company recognizes revenues and expenses generated from daywork and footage drilling contracts as the services are performed as the Company does not bear the risk of completion of the well. 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 can range from one month to two years.

Midstream gas services are primarily undertaken to realize incremental margins on gas purchased at the wellhead, and provide value-added services to customers. Consolidated midstream and marketing revenues represent natural gas sold on behalf of third parties and the fees the Company charges related to gathering, compressing and treating this gas. 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 determined and collectability is reasonably assured.

Revenue from sales of CO_2 is recognized when the product is delivered to the customer.

Environmental Costs. Environmental expenditures are expensed or capitalized, as appropriate, depending on future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no 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, 2010 and 2009 were not material.

Stock-Based Compensation. The Financial Accounting Standards Board's Accounting Standards Codification ("ASC") Topic 718, Compensation — Stock Compensation, establishes the accounting for equity instruments exchanged for employee services. Under ASC Topic 718, stock-based compensation cost is measured based on the calculated fair value of the award on the grant date. The expense is recognized on a straight-line basis over the employee's requisite service period, generally the vesting period of the award. The related excess tax benefit received upon vesting of restricted stock, if any, is reflected in the statement of cash flows as a financing activity. The related excess tax expense due upon vesting of restricted stock, if any, is reflected in the statement of cash flows as an operating activity.

Income Taxes. Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax reporting. Deferred tax assets are reduced by a valuation allowance if a determination is made that it is more likely than not that some or all of the deferred assets will not be realized based on the weight of all available evidence.

The Company has elected an accounting policy in which interest and penalties on income taxes are presented as a component of the income tax provision, rather than as a component of interest expense. Interest and penalties resulting from the underpayment of or the late payment of income taxes due to a taxing authority and interest and penalties accrued relating to income tax contingencies, if any, are presented, on a net of tax basis, as a component of the income tax provision.

Noncontrolling Interest. Effective January 1, 2009, the Company implemented the guidance in ASC Topic 810, Consolidation, which resulted in changes to the presentation for noncontrolling interests. Noncontrolling interest in the Company's subsidiaries represents ownership interests in the consolidated entity and is included as a component of equity in the consolidated balance sheets and consolidated statement of changes in equity as required by ASC Topic 810. All historical periods presented in the accompanying consolidated financial statements reflect these changes to the presentation for noncontrolling interests.

During October 2009, the Company executed amendments to certain agreements related to the ownership and operation of GRLP, the limited partnership that operates the Grey Ranch plant located in Pecos County, Texas. As a result of these amendments, the Company became the primary beneficiary of GRLP. The Company began consolidating the activity of GRLP in its consolidated financial statements prospectively on the effective date of the amendments, or October 1, 2009. The 50% ownership interest not held by the Company is presented as noncontrolling interest in the consolidated financial statements at December 31, 2010 and 2009. See Note 11 for a discussion of GRLP.

At December 31, 2010 and 2009, noncontrolling interest in the Company's consolidated subsidiaries included a 50% interest in GRLP and a 1.29% interest in Cholla Pipeline, LP. At December 31, 2008, noncontrolling interest in the Company's consolidated subsidiaries included a 1.29% interest in Cholla Pipeline, LP.

Concentration of Risk. The Company maintains cash balances at several financial institutions. Accounts at each institution are insured by the Federal Deposit Insurance Corporation up to $250,000. 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 exceeding the federally insured limit.

All of the Company's hedging transactions have been carried out in the over-the-counter market. The use of hedging transactions involves the risk that the counterparties may be unable to meet the financial terms of the transactions. The counterparties for all of the Company's hedging transactions have an "investment grade" credit rating. The Company monitors on an ongoing basis the credit ratings of its hedging counterparties and considers its counterparties' credit default risk rating in determining the fair value of its derivative contracts.

The purchasers of the Company's oil and natural gas production consist primarily of independent marketers, major oil and natural gas companies and gas pipeline companies. The Company has not experienced any significant losses from uncollectible accounts. See Note 25 for information regarding the Company's major customers. The Company believes other purchasers are available in its areas of operations and does not believe the loss of any one purchaser would materially affect the Company's ability to sell the oil and natural gas it produces.

Recently Adopted Accounting Pronouncements. In December 2009, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update 2009-17, "Consolidations — Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities" ("ASU 2009-17"), which codified FASB Statement No. 167, "Amendments to FASB Interpretation No. 46(R)." ASU 2009-17 represents a revision to former FASB Interpretation No. 46(R), "Consolidation of Variable Interest Entities," and changes how a reporting entity determines when an entity that is insufficiently capitalized or is not controlled through voting or similar rights should be consolidated. ASU 2009-17 also requires enhanced disclosures about a reporting entity's involvement with variable interest entities. The Company implemented ASU 2009-17 on January 1, 2010 with no impact on its financial position or results of operations. See Note 11.

In January 2010, the FASB issued Accounting Standards Update 2010-06, "Fair Value Measurements and Disclosures: Improving Disclosures about Fair Value Measurements" ("ASU 2010-06"). ASU 2010-06 requires additional disclosures and clarifies existing disclosure requirements about fair value measurement as set forth in ASC Topic 820, Fair Value Measurements and Disclosures. The Company implemented the new disclosures and clarifications of existing disclosure requirements under ASU 2010-06 effective with the first quarter of 2010, except for certain disclosure requirements regarding activity in Level 3 fair value measurements that are effective for fiscal years beginning after December 15, 2010. The implementation of ASU 2010-06 had no impact on the Company's financial position or results of operations. See Note 3. As the additional requirements under ASU 2010-06, which will be implemented January 1, 2011, pertain to disclosure of Level 3 activity, no effect to the Company's financial position or results of operations is expected.

In December 2010, the FASB issued Accounting Standards Update 2010-28, "Intangibles — Goodwill and Other: When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts" ("ASU 2010-28"). ASU 2010-28 requires step two of the goodwill impairment test to be performed when the carrying value of a reporting unit is zero or negative, if it is more likely than not that a goodwill impairment exists. The Company recorded goodwill as a result of the Arena Acquisition in July 2010, and will be performing the first annual impairment test in July 2011. The requirements of ASU 2010-28 are effective for fiscal years beginning after December 15, 2010, and will be used in conjunction with the Company's first annual goodwill impairment test in 2011. See Note 9 for discussion of the Company's goodwill.

In December 2010, the FASB issued Accounting Standards Update 2010-29, "Business Combinations: Disclosure of Supplementary Pro Forma Information for Business Combinations" ("ASU 2010-29"). ASU 2010-29 clarifies that when presenting comparative pro forma financial statements in conjunction with business combination disclosures, revenue and earnings of the combined entity should be presented as though the business combination that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period. In addition, the update requires a description of the nature and amount of material, nonrecurring pro forma adjustments included in pro forma revenue and earnings that are directly attributable to the business combination. ASU 2010-29 is effective prospectively for business combinations that occur on or after the beginning of the first annual reporting period after December 15, 2010. As ASU 2010-29 relates to disclosure requirements, there will be no impact on the Company's financial condition or results of operations.

2. Acquisitions and Dispositions

2008 Acquisitions and Dispositions

The Company completed the following acquisitions and dispositions in 2008:

- In May 2008, the Company sold all of its assets located in the Piceance Basin of Colorado. Assets sold included undeveloped acreage, working interests in wells, gathering and compression systems and other facilities related to the wells. Net proceeds to the Company were approximately $147.2 million after closing adjustments. The portion of the Company's net proceeds attributable to the disposed gathering and compression systems and facilities exceeded the book basis of those assets resulting in a gain on sale of approximately $7.2 million after closing adjustments. The sale of the acreage and working interests in wells was accounted for as an adjustment to the full cost pool with no gain or loss recognized.
- In July 2008, the Company purchased land, minerals, developed and undeveloped leasehold and interests in producing properties through various transactions for an aggregate purchase price of $67.6 million, which was paid in cash.
- In October 2008, the Company purchased certain working interests and related reserves in Company wells owned by the Company's Chairman and Chief Executive Officer and certain of his affiliates. The purchase price of approximately $67.3 million, after closing adjustments, was paid in cash.

2009 Acquisitions and Dispositions

The Company completed the following acquisitions and dispositions in 2009:

- In June 2009, the Company completed the sale of its gathering and compression assets located in the Piñon Field, which is located in Pecos County and Terrell County, Texas. Net proceeds to the Company were approximately $197.5 million, resulting in a loss of $26.1 million. In conjunction with the sale, the Company entered into a gas gathering agreement and an operations and maintenance agreement. Under the gas gathering agreement, the Company has dedicated its Piñon Field acreage for priority gathering services for a period of 20 years and the Company will pay a fee that was negotiated at arms' length for such services. Pursuant to the operations and maintenance agreement, the Company will operate and maintain the gathering system assets sold for a period of 20 years unless the Company or the buyer of the assets chooses to terminate the agreement.

- In June 2009, the Company completed the sale of its drilling rights in East Texas below the depth of the Cotton Valley formation. After post-closing adjustments, total net proceeds received were $58.5 million. The sale of the drilling rights was accounted for as an adjustment to the full cost pool with no gain or loss recognized by the Company.

- In December 2009, the Company purchased developed and undeveloped oil and natural gas properties located in the Permian Basin from Forest for $791.7 million, net of purchase price and post-closing adjustments. The acquisition qualified as a business combination and, as such, the Company estimated the fair value of the properties as of the December 21, 2009 acquisition date, which is the date the Company obtained control of the properties. The Company used a discounted cash flow model and made market assumptions about future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. These assumptions are classified as Level 3 inputs under the fair value hierarchy described in Note 3.

  The estimated fair value of these properties approximates the consideration paid to Forest, which the Company concluded approximates the fair value that would be paid by a typical market participant. As a result, no goodwill was recognized related to the acquisition. The acquisition-related costs of $0.3 million have been expensed as incurred in general and administrative expense on the consolidated income statements for both of the years ended December 31, 2010 and 2009. In the third quarter of 2010, the Company completed its valuation of assets acquired and liabilities assumed from Forest and made no significant changes to the initial allocation.

  The following table summarizes the consideration paid to Forest and the amounts of the assets acquired and liabilities assumed as of December 21, 2009.

	(In thousands)
Consideration paid to Forest:	
Cash, net of accrued purchase price adjustment	$795,074
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Proved developed and undeveloped properties	754,185
Unproved leasehold properties	52,246
Asset retirement obligation	(11,357)
Total identifiable net assets	$795,074

The unaudited financial information in the table below summarizes the combined results of the Company's operations and the properties acquired from Forest, on a pro forma basis, as though the purchase had taken place at the beginning of each period presented. The pro forma information is based on the Company's consolidated results of operations for the years ended December 31, 2009 and 2008, on historical results of the properties acquired, and on estimates of the effect of the transactions to the combined results. The pro forma information is not necessarily indicative of results that actually would have occurred had the transaction been in effect for the periods indicated, or of results that may occur in the future.

	Year Ended December 31,			
	2009		2008	
	Actual	Pro Forma	Actual	Pro Forma
	(In thousands, except per share data)	(Unaudited)		(Unaudited)
Revenues	$ 591,044	$ 682,593	$ 1,181,814	$ 1,373,834
Net loss attributable to SandRidge Energy, Inc.	$(1,775,590)	$(1,928,754)	$(1,441,280)	$(1,671,496)
Loss applicable to SandRidge Energy, Inc. common stockholders	$(1,784,403)	$(1,949,567)	$(1,457,512)	$(1,699,728)
Loss per common share				
Basic	$ (10.20)	$ (9.72)	$ (9.36)	$ (9.38)
Diluted	$ (10.20)	$ (9.72)	$ (9.36)	$ (9.38)

2010 Acquisitions and Dispositions

The Company completed the following acquisitions and dispositions in 2010:

- On July 16, 2010, the Company acquired all of the outstanding common stock of Arena. At the time of the acquisition, Arena was engaged in oil and natural gas exploration, development and production, with activities in Oklahoma, Texas, New Mexico and Kansas. In connection with the acquisition, the Company issued 4.7771 shares of its common stock and paid $4.50 in cash to Arena stockholders for each outstanding share of Arena unrestricted common stock. In addition, outstanding options to purchase Arena common stock that were deemed exercised pursuant to the merger agreement were converted into shares of Company common stock pursuant to a formula in the merger agreement, and outstanding shares of Arena restricted common stock were converted into restricted shares of Company common stock pursuant to a formula in the merger agreement. Approximately 39.8 million shares of Arena common stock, comprised of 39.5 million shares of Arena common stock outstanding and 0.3 million common shares attributable to Arena options exercised immediately prior to the acquisition in accordance with the merger agreement, were outstanding on the acquisition date. This resulted in the issuance of approximately 190.3 million shares of Company common stock and payment of approximately $177.9 million in cash for an aggregate estimated purchase price to stockholders of Arena equal to approximately $1.4 billion. For purposes of purchase accounting, the value of the common stock issued was determined based on the closing price of $6.55 per share of the Company's common stock on the New York Stock Exchange at the acquisition date, July 16, 2010. The Company has incurred approximately $17.0 million in costs related to the acquisition, which have been included in general and administrative expenses in the accompanying consolidated statement of operations for the year ended December 31, 2010.

  A preliminary allocation of the purchase price as of July 16, 2010 was prepared in connection with the Company's September 30, 2010 consolidated financial statements. During the fourth quarter of 2010, the Company updated certain of the estimates used in the purchase price allocation, primarily with respect to deferred taxes and other accruals for which the Company was awaiting confirmatory information. The following allocation, while still preliminary with respect to final deferred tax amounts, pending completion of the 2010 Arena tax return, and certain accruals, is based on information that was available to management at the time these annual consolidated financial statements were prepared. The Company believes the estimates used are reasonable and the significant effects of the transaction are properly reflected. However, the estimates, primarily the amounts related to deferred taxes, are subject to change as additional information becomes available and is assessed by the Company. Changes to the purchase price allocation could result in a change to goodwill.

The following table summarizes the estimated values of assets acquired and liabilities assumed (in thousands):

Current assets	$ 82,475
Oil and natural gas properties(1)	1,587,630
Other property, plant and equipment	5,963
Long-term deferred tax assets	27,425
Other long-term assets	16,181
Goodwill(2)	234,356
Total assets acquired	1,954,030
Current liabilities	43,822
Long-term deferred tax liability(2)	474,925
Other long-term liabilities	8,851
Total liabilities assumed	527,598
Net assets acquired	$1,426,432

(1) Weighted average commodity prices utilized in the preliminary determination of the fair value of oil and natural gas properties were $105.58 per barrel of oil and $8.56 per Mcf of natural gas, after adjustment for transportation fees and regional price differentials. The prices utilized were based upon forward commodity strip prices, as of July 16, 2010, for the first four years and escalated for inflation at a rate of 2.5% annually beginning with the fifth year through the end of production, which was more than 50 years. Approximately 91.0% of the fair value allocated to oil and natural gas properties is attributed to oil reserves.

(2) The Company received carryover tax basis in Arena's assets and liabilities because the merger was not a taxable transaction under the Internal Revenue Code ("IRC"). Based upon the preliminary purchase price allocation, a step-up in basis related to the property acquired from Arena resulted in a net deferred tax liability of approximately $447.5 million, which in turn contributed to an excess of the consideration transferred to acquire Arena over the estimated fair value on the acquisition date of the net assets acquired, or goodwill. See Note 9 for further discussion of goodwill. The newly created net deferred tax liability was offset with the Company's existing net deferred tax asset, resulting in the release of $447.5 million in the Company's valuation allowance against its existing net deferred tax asset. The release of the valuation allowance resulted in an income tax benefit that was included in the accompanying consolidated statement of operations for the year ended December 31, 2010. Further changes to the deferred tax amounts in the purchase price allocation above would result in a corresponding change in the release of the Company's valuation allowance and corresponding income tax expense (benefit). See Note 18 for additional discussion regarding the tax impact of the Arena Acquisition.

The following unaudited pro forma results of operations are provided for the years ended December 31, 2010 and 2009 as though the Arena Acquisition had been completed as of the beginning of each year presented. The pro forma information is based on the Company's consolidated results of operations for the years ended December 31, 2010 and 2009, on Arena's historical results of operations and on estimates of the effect of the transaction on the combined results. These supplemental pro forma results of operations are provided for illustrative purposes only and do not purport to be indicative of the actual results that would have been achieved by the combined company for the periods presented or that may be achieved by the combined company in the future. Future results may vary significantly from the results reflected in this pro forma financial information because of future events and transactions, as well as other factors.

	Year Ended December 31,			
	2010		2009	
	Actual	Pro Forma	Actual	Pro Forma
		(In thousands, except per share data) (Unaudited)		(Unaudited)
Revenues	$931,736	$1,046,569	$ 591,044	$ 717,285
Net income (loss) attributable to SandRidge Energy, Inc.	$190,565	$ 200,159	$(1,775,590)	$(1,451,962)
Income available (loss applicable) to SandRidge Energy, Inc. common stockholders(1)(2)	$153,123	$ 162,717	$(1,784,403)	$(1,460,775)
Earnings (loss) per common share				
Basic	$ 0.52	$ 0.41	$ (10.20)	$ (4.00)
Diluted	$ 0.52	$ 0.41	$ (10.20)	$ (4.00)

(1) Includes a $447.5 million reduction in tax expense for all periods presented related to the release of a portion of the Company's valuation allowance on existing deferred tax assets resulting from deferred tax liabilities arising from the acquisition of Arena.

(2) Includes approximately $165.0 million of additional estimated impairment from full cost ceiling limitations for the year ended December 31, 2009.

The pro forma combined results of operations have been prepared by adjusting the historical results of the Company to include the historical results of Arena, certain reclassifications to conform Arena's presentation to the Company's accounting policies and the impact of the preliminary purchase price allocation discussed above. The pro forma results of operations do not include any cost savings or other synergies that may result from the acquisition or any estimated costs that have been or will be incurred by the Company to integrate Arena.

Revenues of $112.1 million and earnings of $90.1 million generated by the oil and natural gas properties acquired from Arena for the period of July 17, 2010 through December 31, 2010 have been included in the Company's accompanying consolidated statement of operations for the year ended December 31, 2010.

- On August 26, 2010, the Company sold certain deep acreage rights in the Cana Shale play in Western Oklahoma for estimated net proceeds of $110.0 million, subject to final post-closing adjustments. The sale of the deep acreage rights was accounted for as an adjustment to the full cost pool with no gain or loss recognized. The Company retained the shallow rights associated with this acreage.

- On December 10, 2010, the Company sold approximately 40,000 net acres of non-core assets in the Avalon Shale and Bone Spring reservoirs of the Permian Basin for $110.0 million, subject to certain post-closing adjustments. There was no production or proved reserves associated with these assets and the Company retained all rights above and below the Avalon Shale and Bone Spring formations.

3. Fair Value Measurements

The Company applies the guidance provided under ASC Topic 820 to its financial assets and liabilities and nonfinancial liabilities that are measured and reported on a fair value basis. Pursuant to this guidance, the Company has classified and disclosed its fair value measurements using the following levels of the fair value hierarchy:

Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities.

Level 2: Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability.

Level 3: Measurement based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable for objective sources (*i.e.*, supported by little or no market activity).

Assets and liabilities that are measured at fair value are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels as described in ASC Topic 820. The determination of the fair values, stated below, takes into account the market for the Company's financial assets and liabilities, the associated credit risk and other factors as required by ASC Topic 820. The Company considers active markets as those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis. The Company has assets and liabilities it has classified as Level 1 and Level 3, as described below. At December 31, 2010 and 2009, the Company did not have any assets or liabilities classified as Level 2.

Level 1 Fair Value Measurements

Restricted deposits. The fair value of restricted deposits is based on quoted market prices.

Other long-term assets. The fair value of other long-term assets, consisting of assets attributable to the Company's deferred compensation plan, is based on quoted market prices.

Level 3 Fair Value Measurements

Derivative Contracts. The fair values of the Company's oil and natural gas fixed price swaps, natural gas basis swaps, oil and natural gas collars and interest rate swaps are based upon quotes obtained from counterparties to the derivative contracts. The Company reviews other readily available market prices for its derivative contracts as there is an active market for these contracts. However, the Company does not have access to the specific valuation models used by its counterparties or other market participants. Included in these models are discount factors that the Company must estimate in its calculation. Additionally, the Company applies a weighted average credit default risk rating factor for its counterparties or gives effect to its credit risk, as applicable, in determining the fair value of its derivative contracts. Based on the inputs for the fair value measurement, the Company has classified its derivative contract assets and liabilities as Level 3.

The following tables summarize the Company's financial assets and liabilities measured at fair value on a recurring basis by the fair value hierarchy (in thousands):

December 31, 2010

	Fair Value Measurements				Assets/ Liabilities at
	Level 1	Level 2	Level 3	Netting(1)	Fair Value
Assets					
Commodity derivative contracts	$ —	$—	$ 10,576	$(5,548)	$ 5,028
Restricted deposits	27,886	—	—	—	27,886
Other long-term assets	4,826	—	—	—	4,826
	$32,712	$—	$ 10,576	$(5,548)	$ 37,740
Liabilities					
Commodity derivative contracts	$ —	$—	$216,436	$(5,548)	$210,888
Interest rate swaps	—	—	16,694	—	16,694
	$ —	$—	$233,130	$(5,548)	$227,582

December 31, 2009

	Fair Value Measurements				Assets/ Liabilities at
	Level 1	Level 2	Level 3	Netting(1)	Fair Value
Assets					
Commodity derivative contracts	$ —	$—	$161,197	$(55,203)	$105,994
Restricted deposits	32,894	—	—	—	32,894
Other long-term assets	6,251	—	—	—	6,251
	$39,145	$—	$161,197	$(55,203)	$145,139
Liabilities					
Commodity derivative contracts	$ —	$—	$115,044	$(55,203)	$ 59,841
Interest rate swaps	—	—	8,299	—	8,299
	$ —	$—	$123,343	$(55,203)	$ 68,140

(1) Represents the impact of netting assets and liabilities with counterparties with which the right of offset exists.

The table below sets forth a reconciliation of the Company's financial assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) during the years ended December 31, 2008, 2009 and 2010 (in thousands):

	Commodity Derivative Contracts	Interest Rate Swaps	Total
Balance of Level 3, January 1, 2008	$ 22,228	$ —	$ 22,228
Total gains or losses (realized/unrealized)	211,439	(7,441)	203,998
Purchases, issuances and settlements	12,981	(1,304)	11,677
Transfers in and out of Level 3	—	—	—
Balance of Level 3, December 31, 2008	246,648	(8,745)	237,903
Total gains or losses (realized/unrealized)	147,527	(5,783)	141,744
Purchases, issuances and settlements	(348,022)	6,229	(341,793)
Transfers in and out of Level 3	—	—	—
Balance of Level 3, December 31, 2009	46,153	(8,299)	37,854
Total gains or losses (realized/unrealized)	(50,872)	(16,540)	(67,412)
Purchases, issuances and settlements	(201,141)	8,145	(192,996)
Transfers in and out of Level 3	—	—	—
Balance of Level 3, December 31, 2010	$(205,860)	$(16,694)	$(222,554)

During the years ended December 31, 2010, 2009 and 2008, the Company did not have any transfers between Level 1, Level 2 or Level 3 fair value measurements.

See Note 16 for further discussion of the Company's derivative contracts.

Fair Value of Debt

The Company measures fair value of its long-term debt based on quoted market prices and with consideration given to the effect of the Company's credit risk. The estimated fair value of the Company's senior notes and the carrying value at December 31, 2010 and 2009 were as follows (in thousands):

	December 31, 2010		December 31, 2009	
	Fair Value	Carrying Value	Fair Value	Carrying Value
Senior Floating Rate Notes due 2014	$334,751	$350,000	$316,859	$350,000
8.625% Senior Notes due 2015	663,181	650,000	655,470	650,000
9.875% Senior Notes due 2016(1)	394,527	352,707	390,692	351,021
8.0% Senior Notes due 2018	762,849	750,000	739,778	750,000
8.75% Senior Notes due 2020(2)	472,968	443,057	451,890	442,590

(1) Carrying value is net of $12,793 and $14,479 discount at December 31, 2010 and 2009, respectively.
(2) Carrying value is net of $6,943 and $7,410 discount at December 31, 2010 and 2009, respectively.

The carrying value for the Company's senior credit facility and remaining fixed rate debt instruments approximate fair value based on current rates applicable to similar instruments. See Note 14 for further discussion of the Company's long-term debt.

4. Accounts Receivable

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

	December 31,	
	2010	2009
Oil and natural gas sales	$104,587	$ 82,472
Oil and natural gas services	14,015	10,484
Joint interest billing	25,200	10,101
Related party	1,702	64
Other	2,117	5,945
	147,621	109,066
Less allowance for doubtful accounts	(1,503)	(3,590)
Total trade accounts receivable, net	$146,118	$105,476

The following table shows the balance in the allowance for doubtful accounts and activity for the years ended December 31, 2010, 2009 and 2008 (in thousands):

	Year Ended December 31,		
	2010	2009	2008
Allowance for doubtful accounts, January 1	$ 3,590	3,874	2,238
Additions charged to costs and expenses	129	214	1,748
Deductions(1)	(2,216)	(498)	(112)
Allowance for doubtful accounts, December 31	$ 1,503	$3,590	$3,874

(1) Deductions represent write-off of receivables.

The Company's customer, SemGroup, L.P. and certain of its subsidiaries (collectively, "SemGroup"), filed for bankruptcy on July 22, 2008. During 2008, the Company established an allowance in the amount of $1.5 million for all amounts due from SemGroup. During 2010, the Company received approximately $0.7 million from SemGroup, and wrote off the remaining $0.8 million balance for a total reduction of the allowance of $1.5 million.

5. Other Current Assets

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

	December 31,	
	2010	2009
Prepaid insurance	$ 7,840	$ 7,627
Deposits	1,326	7,499
Prepaid drilling	1,826	1,804
Other	3,644	3,650
Total other current assets	$14,636	$20,580

6. Property, Plant and Equipment

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

	December 31, 2010	December 31, 2009
Oil and natural gas properties:		
Proved	$ 8,159,924	$ 5,913,408
Unproved	547,953	281,811
Total oil and natural gas properties	8,707,877	6,195,219
Less accumulated depreciation, depletion and impairment(1)	(4,483,736)	(4,223,437)
Net oil and natural gas properties capitalized costs	4,224,141	1,971,782
Land	14,418	13,937
Non oil and natural gas equipment(2)	666,233	594,132
Buildings and structures	89,813	78,584
Total	770,464	686,653
Less accumulated depreciation and amortization	(260,740)	(224,792)
Net capitalized costs	509,724	461,861
Total property, plant and equipment	$ 4,733,865	$ 2,433,643

(1) Includes cumulative full cost ceiling limitation impairment charges of $3,548.3 million at both December 31, 2010 and 2009. See Note 7.

(2) Includes capitalized interest of approximately $4.7 million and $3.8 million at December 31, 2010 and 2009, respectively.

The average rates used for depreciation and depletion of oil and natural gas properties were $13.70 per Boe or $2.28 per Mcfe in 2010, $10.08 per Boe or $1.68 per Mcfe in 2009 and $17.21 per Boe or $2.87 per Mcfe in 2008.

Costs Excluded from Amortization

Costs associated with unproved properties of $548.0 million as of December 31, 2010 were excluded from amounts subject to amortization. The following table summarizes the costs related to unproved properties, along with pipe inventory and the current loss estimate on construction of the Century Plant, which have been excluded from oil and natural gas properties being amortized at December 31, 2010 and the year in which they were incurred (in thousands):

	Total	Year Cost Incurred 2010	2009	2008	2007	2006
Property acquisition	$544,645	$347,643	$54,089	$33,707	$—	$109,206
Exploration(1)	84,800	16,457	45,564	22,779	—	—
Development(2)	105,000	105,000	—	—	—	—
Capitalized interest	—	—	—	—	—	—
Total costs incurred	$734,445	$469,100	$99,653	$56,486	$—	$109,206

(1) Includes $81.4 million of pipe inventory with $15.2 million in 2010, $43.5 million in 2009 and $22.7 million in 2008.

(2) Estimated loss currently identified on the construction of the Century Plant. Amount will become subject to amortization when the Century Plant has been placed into its intended use. See Note 13.

The Company expects to complete the majority of the evaluation activities within six years from the applicable date of acquisition, contingent on the Company's capital expenditures and drilling program. In addition, the Company's internal engineers evaluate all properties on at least an annual basis.

7. Impairment

Full Cost Ceiling Limitation. During the first quarter and the fourth quarter of 2009, the Company reduced the carrying value of its oil and natural gas properties by $1,304.4 million and $388.9 million, respectively, due to a full cost ceiling limitation. As a result of the Company's full valuation allowance on its net deferred tax asset, there was no tax effect on the full cost ceiling impairments taken in 2009. During the fourth quarter of 2008, the Company reduced the carrying value of its oil and natural gas properties by $1,855.0 million due to a full cost ceiling limitation. The after-tax effect of this reduction in 2008 was $1,677.5 million. There were no full cost ceiling impairments during the year ended December 31, 2010.

Other Property, Plant and Equipment. The Company recorded a $10.0 million impairment in the fourth quarter of 2009 on its spare parts inventory due to a decline in market value. The inventory was classified as fixed assets due to the Company's intent to place the parts into service in the future. Also in the fourth quarter of 2009, the Company recorded a $3.9 million impairment on three buildings located on its downtown Oklahoma City campus. The Company has determined these buildings will not have use or value in the future. There were no such impairments during 2010 or 2008.

Larclay, L.P. During 2008, Larclay, a limited partnership in which Lariat then owned a 50% interest, experienced cash shortfalls as a result of its principal payments due pursuant to its rig loan agreement. As permitted under the Larclay partnership agreement, Lariat provided loans to Larclay to offset the cash shortfalls. At December 31, 2008, the notes outstanding to Larclay and related interest receivable were $7.5 million and $0.2 million, respectively. With the significant decline in oil and natural gas prices in the fourth quarter of 2008, the demand for Larclay's drilling rigs and land drilling services decreased. Due to economic conditions, oil and natural gas prices and the continued cash shortfalls for Larclay, Lariat fully impaired its $4.8 million investment in Larclay, as well as notes and accrued interest receivable due from Larclay totaling $7.7 million, as of December 31, 2008. This resulted in an impairment expense of approximately $12.5 million included in the consolidated statement of operations for the year ended December 31, 2008. As further discussed in Note 23, Lariat assigned its 50% equity interest in Larclay to CWEI in April 2009. No further impairment was taken on Larclay.

8. Restricted Deposits

Restricted deposits represent bank trust and escrow accounts required by BOEMR, 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. There were no deposits to the escrow accounts in 2010 or 2009. During 2010, $5.1 million was liquidated from the escrow accounts upon compliance with certain plugging and abandonment obligations.

9. Goodwill

At December 31, 2010, the Company had $234.4 million of goodwill, including the effects of the $5.4 million purchase price adjustment recorded in December 2010, as a result of the excess consideration transferred over the fair value of Arena net assets acquired on July 16, 2010. Goodwill recorded in the Arena Acquisition is primarily attributable to operational and cost synergies expected to be realized from the acquisition by using the Company's current presence in the Permian Basin, its Fort Stockton service base and its current rig ownership to efficiently increase its drilling and oil production from the Central Basin Platform assets acquired, as these assets have a proven production history. See Note 2 for additional information on the Arena Acquisition. The Company assigned all of the goodwill related to the Arena Acquisition to its exploration and production segment, which will be the reporting unit for impairment testing purposes. The Company will test goodwill for impairment annually on July 1st, beginning in 2011. The Company monitors the existence of potential impairment indicators throughout the year. As of December 31, 2010, no such events were noted. Goodwill recognized will not be deductible for tax purposes.

10. Other Assets

Other assets consist of the following (in thousands):

	December 31,	
	2010	2009
Debt issuance costs, net of amortization	$50,637	$49,103
Investments	4,826	6,251
Other	4,288	2,462
Total other assets	$59,751	$57,816

11. Variable Interest Entities

In accordance with the guidance in ASC Topic 810, including the guidance in ASU 2009-17, the Company consolidates the activities of variable interest entities ("VIEs") of which it is the primary beneficiary. The primary beneficiary of a VIE is that variable interest holder possessing a controlling financial interest through (i) its power to direct the activities of the VIE that most significantly impact the VIE's economic performance and (ii) its obligation to absorb losses or its right to receive benefits from the VIE that could potentially be significant to the VIE. In order to determine whether the Company owns a variable interest in a VIE, a qualitative analysis of the entity's design, organizational structure, primary decision makers and related financial agreements is performed.

The Company's significant associated VIEs, including those for which the Company has determined it is the primary beneficiary and those for which it has determined it is not, are described below.

Grey Ranch Plant, L.P. Primarily engaged in treating and transportation of natural gas, GRLP is a limited partnership that operates the Company's Grey Ranch plant (the "Plant") located in Pecos County, Texas. The Company has long-term operating and gathering agreements with GRLP and also owns a 50% ownership interest in GRLP. Income or losses of GRLP are allocated to the partners based on ownership percentage and any operating or cash shortfalls require contributions from the partners. The Company has determined that GRLP qualifies as a VIE under the provisions of ASC Topic 810. During October 2009, the Company executed amendments to certain agreements related to the ownership and operation of GRLP. The amended operating agreements provide for GRLP to pay management fees to the Company to operate the Plant and lease payments for the Plant. Under the operating agreements, lease payments are reduced if throughput volumes are below those expected. The Company has determined that it is the primary beneficiary of GRLP as it has both (i) the power to direct the activities of GRLP that most significantly impact its economic performance as operator of the Plant and (ii) the obligation to absorb losses, as a result of the operating and gathering agreements, that could potentially be significant to GRLP.

Prior to October 2009, the Company accounted for its ownership interest in GRLP using the equity method of accounting; however, due to the agreement amendments discussed above, the Company began consolidating the activity of GRLP in its consolidated financial statements prospectively on the effective date of the amendments, October 1, 2009. The change from equity method accounting to the consolidation of GRLP activity had no effect on the Company's net income. The ownership interest not held by the Company is presented as noncontrolling interest in the consolidated financial statements.

At December 31, 2010 and 2009, consolidated amounts related to GRLP included assets of $21.1 million and $22.5 million, respectively, and liabilities of $0.4 million and $2.0 million, respectively. GRLP's assets can only be used to settle its obligations. Although GRLP is included in the Company's consolidated financial statements, the Company's legal interest in GRLP's assets is limited to its 50% ownership. At December 31, 2010 and 2009, $11.3 million and $10.0 million, respectively, of noncontrolling interest in the accompanying consolidated balance sheets were related to GRLP. GRLP's creditors have no recourse to the general credit of the Company.

Grey Ranch Plant Genpar, LLC. The Company owns a 50% interest in Grey Ranch Plant Genpar, LLC ("Genpar"), the managing partner and 1% owner of GRLP. Additionally, the Company serves as Genpar's administrative manager. Genpar's ownership interest in GRLP is its only asset.

As managing partner of GRLP, Genpar has the sole right to manage, control and conduct the business of GRLP. However, Genpar is restricted from making certain major decisions, including the decision to remove the Company as operator of the Plant. The rights afforded the Company under the Plant operating agreement and the restrictions on Genpar serve to limit Genpar's ability to make decisions on behalf of GRLP. Therefore, Genpar is considered a VIE. Although both the Company and Genpar's other equity owner share equally in Genpar's economic losses and benefits and also have agreements that may be considered variable interests, the Company determined it was the primary beneficiary due to (i) its ability, as administrative manager, to direct the activities of Genpar that most significantly impact its performance and (ii) its obligation or right, as operator of the Plant, to absorb the losses of or receive benefits from Genpar that could potentially be significant to Genpar. As the primary beneficiary, the Company consolidates Genpar's activity. However, its sole asset, the investment in GRLP, is eliminated in consolidation. Genpar has no liabilities.

Piñon Gathering Company, LLC. The Company has 20-year gas gathering and operations and maintenance agreements with Piñon Gathering Company, LLC ("PGC"), the entity that purchased the Company's gathering and compression assets located in the Piñon Field in June 2009. Under the gas gathering agreement, the Company is required to compensate PGC for any throughput shortfalls below a required minimum volume. By guaranteeing a minimum throughput, the Company absorbs the risk that lower than projected volumes will be gathered by the gathering system. Therefore, PGC is a VIE. While the Company operates the assets of PGC as directed under the operations and management agreement, the member and managers of PGC have the authority to directly control PGC and make substantive decisions regarding PGC's activities including terminating the Company as operator without cause. As the Company does not have the ability to control the activities of PGC that most significantly impact PGC's economic performance, the Company is not the primary beneficiary of PGC.

12. Accounts Payable and Accrued Expenses

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

	December 31,	
	2010	2009
Accounts payable	$275,385	$134,598
Convertible perpetual preferred stock dividends	17,363	8,813
Payroll and benefits	29,187	18,270
Drilling advances	1,734	4,985
Conoco settlement agreement — current	5,000	5,000
Accrued interest	47,453	31,382
Related party	800	860
Total trade accounts payable and accrued expenses	$376,922	$203,908

13. Century Plant Contract

The Company is constructing the Century Plant, a CO_2 treatment plant in Pecos County, Texas, and associated compression and pipeline facilities pursuant to an agreement with Occidental. Under the terms of the agreement, the Company will construct the Century Plant and Occidental will pay the Company a minimum of 100% of the contract price, or $800.0 million, plus any subsequently agreed-upon revisions, through periodic cost reimbursements based upon the percentage of the project completed by the Company. The Company expects to complete the Century Plant in two phases. Upon completion of each phase of the Century Plant, Occidental will take ownership of the related assets and will operate the Century Plant for the purpose of separating and removing CO_2 from delivered natural gas. Phase I is in the commissioning process with completion and transfer of ownership to Occidental expected in early 2011. Pursuant to a 30-year treating agreement executed simultaneously with the construction agreement, Occidental will remove CO_2 from the Company's delivered production volumes. The Company will retain all methane gas from the natural gas it delivers to the Century Plant.

The Company accounts for construction of the Century Plant using the completed-contract method, under which contract revenues and costs are recognized when work under both phases of the contract is completed and assets have been transferred to Occidental. In the interim, costs incurred on and billings related to contracts in process are accumulated on the balance sheet. Contract gains or losses will be recorded, as development costs within the Company's oil and natural gas properties as part of the full cost pool, when it is determined that a gain or loss will be incurred. During 2010, the Company recorded an addition of $105.0 million ($98.0 million in the third quarter and $7.0 million in the fourth quarter) to its oil and natural gas properties for the estimated loss identified based on current projections of the costs to be incurred in excess of contract amounts. At December 31, 2009, no amounts had been recorded in anticipation of probable and estimable gains or losses. Billings and estimated contract loss in excess of costs incurred were $31.5 million and were reported as current liabilities in the accompanying consolidated balance sheet at December 31, 2010. Costs in excess of billings were $12.3 million at December 31, 2009 and were reported as current assets in the accompanying consolidated balance sheet.

14. Long-Term Debt

Long-term debt consists of the following (in thousands):

	December 31, 2010	December 31, 2009
Senior credit facility	$ 340,000	$ —
Other notes payable:		
Drilling rig fleet and related oil field services equipment	6,302	17,375
Mortgage	17,020	17,952
Senior Floating Rate Notes due 2014	350,000	350,000
8.625% Senior Notes due 2015	650,000	650,000
9.875% Senior Notes due 2016, net of $12,793 and $14,479 discount, respectively	352,707	351,021
8.0% Senior Notes due 2018	750,000	750,000
8.75% Senior Notes due 2020, net of $6,943 and $7,410 discount, respectively	443,057	442,590
Total debt	2,909,086	2,578,938
Less: Current maturities of long-term debt	7,293	12,003
Long-term debt	$2,901,793	$2,566,935

Senior Credit Facility. The amount the Company can borrow under its senior credit facility is limited to a borrowing base. The senior credit facility is available to be drawn on subject to limitations based on its terms and certain financial covenants, as described below. In April 2010, the senior credit facility was amended and restated, affirming the borrowing base at $850.0 million and extending the maturity date to April 15, 2014. In October 2010, the senior credit facility was further amended with no change to the borrowing base. Both the April and October 2010 amendments resulted in changes to the covenants under the senior credit facility, as further described below.

The senior credit facility contains various covenants that limit the ability of the Company and certain of its subsidiaries 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 ability of the Company and certain of its subsidiaries to incur additional indebtedness with certain exceptions.

As of December 31, 2010, the senior credit facility contained financial covenants, including maintaining agreed levels for the (i) ratio of total funded debt to EBITDAX, which may not exceed 4.5:1.0 at each quarter end calculated using the last four completed fiscal quarters (adjusted for annualized amounts of the post-acquisition results of operations of newly acquired properties/entities) and (ii) ratio of current assets to current liabilities, which must be at least 1.0:1.0 at each quarter end. In the current ratio calculation (as defined in the senior credit facility), any amounts available to be drawn under the senior credit facility are included in current assets, and unrealized assets and liabilities resulting from mark-to-market adjustments on the Company's derivative contracts are disregarded. Under the terms of the amended and restated facility, (a) the ratio of EBITDAX to interest expense plus current maturities of long-term debt was eliminated and (b) the Company's ability to make investments was increased from the previous terms. In October 2010, the senior credit facility was amended and, effective with this amendment, the ratio of the Company's secured indebtedness to EBITDAX may not exceed 2.0:1.0 at each quarter end. As of and during the year ended December 31, 2010, the Company was in compliance with all of the financial covenants under the senior credit facility. In February 2011, the Company's senior credit facility was amended. See Note 24 for discussion of the amendment.

The obligations under the senior credit facility are guaranteed by certain Company subsidiaries and are secured by first priority liens on all shares of capital stock of each of the Company's material present and future subsidiaries; all intercompany debt of the Company; and substantially all of the Company's assets, including proved oil and natural gas reserves representing at least 80% of the discounted present 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.

At the Company's election, interest under the senior credit facility is determined by reference to (a) the London Interbank Offered Rate ("LIBOR") plus an applicable margin between 2.00% and 3.00% per annum or (b) the 'base rate,' which is the higher of (i) the federal funds rate plus 0.5%, (ii) the prime rate published by Bank of America or (iii) the Eurodollar rate (as defined in the senior credit facility) plus 1.00% per annum, plus, in each case under scenario (b), an applicable margin between 1.00% and 2.00% 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 annual interest rate paid on amounts outstanding under the senior credit facility was 2.70%, 2.33% and 2.19% for the years ended December 31, 2010, 2009 and 2008, respectively.

Borrowings under the senior credit facility may not exceed the lower of the borrowing base or the committed amount. The Company's borrowing base is redetermined in April and October of each year. With respect to each redetermination, the administrative agent and the lenders under the senior credit facility consider several factors, including the Company's proved reserves and projected cash requirements, and make assumptions regarding, among other things, oil and natural gas prices and production. Because the value of the Company's proved reserves is a key factor in determining the amount of the borrowing base, changing commodity prices and the Company's success in developing reserves may affect the borrowing base. The borrowing base remained unchanged at $850.0 million as a result of the April and October 2010 redeterminations. The Company has, at times, incurred additional costs related to the senior credit facility as a result of amendments to the credit agreement and changes to the borrowing base. During 2010, additional costs of approximately $12.3 million were incurred. These costs have been deferred and are included in other assets in the accompanying consolidated balance sheets.

At December 31, 2010, the Company had $340.0 million outstanding under the senior credit facility and $37.3 million in outstanding letters of credit, which affect the availability under the senior credit facility on a dollar-for-dollar basis.

Other Notes Payable. The Company has financed a portion of its drilling rig fleet and related oil field services equipment through the issuance of notes secured by such equipment. At December 31, 2010, the aggregate outstanding balance of these notes was $6.3 million, with annual fixed interest rates ranging from 8.49% to 8.67%. The notes have a final maturity date of December 1, 2011. The notes have a prepayment penalty (currently ranging from 0.50% to 1.00%) that is triggered if the Company repays the notes prior to maturity.

The debt incurred to purchase the downtown Oklahoma City property that serves as the Company's corporate headquarters is fully secured by a mortgage on one of the buildings located on the property. The note underlying the mortgage 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 2010, the Company made payments of principal and interest on this note totaling $0.9 million and $1.1 million, respectively.

Senior Floating Rate Notes Due 2014 and 8.625% Senior Notes Due 2015. The Company's Senior Floating Rate Notes due 2014 (the "Senior Floating Rate Notes") and 8.625% Senior Notes due 2015 (the "8.625% Senior Notes") were issued in May 2008, and jointly and severally, unconditionally guaranteed on an unsecured basis by certain of the Company's wholly owned subsidiaries and are freely tradable as a result of the registered exchange offer in 2008. See Note 26 for condensed financial information of the subsidiary guarantors.

The Senior Floating Rate Notes bear interest at LIBOR plus 3.625% (3.92% at December 31, 2010). Interest is payable quarterly with the principal due on April 1, 2014. The average interest rates paid on the outstanding Senior Floating Rate Notes for the years ended December 31, 2010, 2009 and 2008 was 3.97%, 4.57% and 7.27%, respectively, without consideration of the interest rate swap discussed below. The 8.625% Senior Notes bear interest at a fixed rate of 8.625% per annum with the principal due on April 1, 2015. Under the terms of the 8.625% Senior Notes, interest is payable semi-annually.

The Company has entered into two $350.0 million notional interest rate swap agreements to fix the variable interest rate on the Senior Floating Rate Notes through April 1, 2013. The first interest rate swap agreement serves to fix the rate on the Senior Floating Rate Notes at an annual rate of 6.26% through April 1, 2011. The second interest rate swap agreement serves to fix the rate on the Senior Floating Rate Notes at an annual rate of 6.69% for the period from April 1, 2011 to April 1, 2013. The two interest rate swaps effectively serve to fix the Company's variable interest rate on its Senior Floating Rate Notes for the majority of the term of these notes. These swaps have not been designated as hedges.

The Company may redeem, at specified redemption prices, some or all of the Senior Floating Rate Notes at any time and some or all of the 8.625% Senior Notes on or after April 1, 2011.

The $26.3 million of debt issuance costs associated with the Senior Floating Rate Notes and the 8.625% Senior Notes are included in other assets in the accompanying consolidated balance sheets and are being amortized over the term of the notes.

9.875% Senior Notes Due 2016. The Company's unsecured 9.875% Senior Notes due 2016 (the "9.875% Senior Notes") were issued in May 2009 and bear interest at a fixed rate of 9.875% per annum, payable semi-annually, with the principal due on May 15, 2016. The 9.875% Senior Notes were issued at a discount, which is amortized into interest expense over the term of the notes. The 9.875% Senior Notes are redeemable, in whole or in part, prior to their maturity at specified redemption prices and are jointly and severally, unconditionally guaranteed on an unsecured basis by all of the Company's wholly owned subsidiaries, except certain minor subsidiaries, and are freely tradable.

Debt issuance costs of $7.9 million incurred in connection with the offering of the 9.875% Senior Notes are included in other assets in the accompanying consolidated balance sheets and are being amortized over the term of the notes.

8.0% Senior Notes Due 2018. The Company's unsecured 8.0% Senior Notes due 2018 (the "8.0% Senior Notes") were issued in May 2008 and bear interest at a fixed rate of 8.0% per annum, payable semi-annually, with the principal due on June 1, 2018. The notes are redeemable, in whole or in part, prior to their maturity at specified redemption prices and are jointly and severally, unconditionally guaranteed on an unsecured basis, by all of the Company's wholly owned subsidiaries, except certain minor subsidiaries, and are freely tradable.

The Company incurred $16.0 million of debt issuance costs in connection with the offering of the 8.0% Senior Notes. These costs are included in other assets in the accompanying consolidated balance sheets and are being amortized over the term of the notes.

8.75% Senior Notes Due 2020. The Company's unsecured 8.75% Senior Notes due 2020 (the "8.75% Senior Notes") were issued in December 2009 and bear interest at a fixed rate of 8.75% per annum, payable semi-annually, with the principal due on January 15, 2020. The 8.75% Senior Notes were issued at a discount which is amortized into interest expense over the term of the notes. The 8.75% Senior Notes are redeemable, in whole or in part, prior to their maturity at specified redemption prices and are jointly and severally, unconditionally guaranteed on an unsecured basis by all of the Company's wholly owned subsidiaries, except certain minor subsidiaries.

In conjunction with the issuance of the 8.75% Senior Notes, the Company entered into a Registration Rights Agreement requiring the Company to register these notes by December 16, 2010. On November 2, 2010, pursuant to an exchange offer, the Company replaced all of the 8.75% Senior Notes, which were issued under Rule 144A and Regulation S under the Securities Act, with 8.75% Senior Notes issued pursuant to a registration statement. The terms of the 8.75% Senior Notes issued in the exchange offer are identical in all material respects to the terms of the exchanged senior notes, except that the transfer restrictions, registration rights and provisions for additional interest relating to the exchanged notes do not apply to the newly issued 8.75% Senior Notes. At the closing of the exchange offer, the 8.75% Senior Notes that were accepted for exchange were cancelled. The exchange offer did not result in the incurrence of any additional indebtedness.

Debt issuance costs of $9.7 million incurred in connection with the offering of and subsequent exchange of the 8.75% Senior Notes are included in other assets in the accompanying consolidated balance sheets and are being amortized over the term of the notes.

Indentures. The indentures governing the Company's senior notes contain limitations on the incurrence of indebtedness, payment of dividends, investments, asset sales, certain asset purchases, transactions with related parties and consolidations or mergers. As of and during the year ended December 31, 2010, the Company was in compliance with all of the covenants contained in the indentures governing the senior notes.

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

Years ending December 31:	
2011	$ 7,293
2012	1,051
2013	1,120
2014	691,191
2015	651,266
Thereafter	1,576,901
Total debt	$2,928,822

15. Other Long-Term Obligations

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

	December 31,	
	2010	2009
Deposit received on property sale	$10,000	$ —
Conoco settlement agreement	—	5,000
Non-qualified deferred compensation plan obligation	4,788	6,969
Natural gas balancing liability	2,080	1,880
Other	2,156	250
Total other long-term obligations	$19,024	$14,099

16. Derivatives

None of the Company's derivative contracts have been designated as hedges. The Company records all derivative contracts, which include commodity derivatives and interest rate swaps, at fair value. Changes in derivative contract fair values are recognized in earnings. Cash settlements and valuation gains and losses are included in loss (gain) on derivative contracts for the commodity derivative contracts and in interest expense for the interest rate swaps in the consolidated statement of operations. Commodity derivative contracts are settled on a monthly basis. Settlements on the interest rate swaps occur quarterly. Derivative assets and liabilities arising from the Company's derivative contracts with the same counterparty that provide for net settlement are reported on a net basis in the consolidated balance sheet.

Commodity Derivatives. The Company is exposed to commodity price risk, which impacts the predictability of its cash flows from the sale of oil and natural gas. The Company seeks to manage this risk through the use of commodity derivative contracts. These derivative contracts allow the Company to limit its exposure to a portion of its projected oil and natural gas sales. None of the Company's derivative contracts may be terminated early as a result of a party to the contract having its credit rating downgraded. At December 31, 2010, the Company's commodity derivative contracts consisted of fixed price swaps, collars and basis swaps, which are described below.

Fixed price swaps: The Company receives a fixed price for the contract and pays a floating market price to the counterparty over a specified period for a contracted volume.

Collars: Collars contain a fixed floor price (put) and a fixed ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, the Company receives the fixed price and pays the market price. If the market price is between the call and the put strike price, no payments are due from either party.

Basis swaps: The Company receives a payment from the counterparty if the settled price differential is greater than the stated terms of the contract and pays the counterparty if the settled price differential is less than the stated terms of the contract, which guarantees the Company a price differential for natural gas from a specified delivery point.

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

The Company has entered into two interest rate swap agreements to manage the interest rate risk on a portion of its floating rate debt by effectively fixing the variable interest rate on its Senior Floating Rate Notes. See Note 14 for further discussion of the Company's interest rate swaps.

Fair Value of Derivatives. In accordance with ASC Topic 815, Derivatives and Hedging, the following table presents the fair value of the Company's derivative contracts as of December 31, 2010 and 2009 on a gross basis without regard to same-counterparty netting (in thousands):

Type of Contract	Balance Sheet Classification	December 31, 2010	December 31, 2009
Derivative assets			
Oil price swaps	Derivative contracts-current	$ —	$ 2,849
Natural gas price swaps	Derivative contracts-current	8,500	152,986
Oil price swaps	Derivative contracts-noncurrent	—	5,362
Natural gas price swaps	Derivative contracts-noncurrent	3,518	—
Derivative liabilities			
Oil price swaps	Derivative contracts-current	(63,123)	(4,127)
Natural gas price swaps	Derivative contracts-current	(640)	—
Natural gas basis swaps	Derivative contracts-current	(34,112)	(45,714)
Interest rate swaps	Derivative contracts-current	(9,007)	(7,080)
Oil price swaps	Derivative contracts-noncurrent	(84,055)	(2,262)
Natural gas price swaps	Derivative contracts-noncurrent	(802)	—
Natural gas basis swaps	Derivative contracts-noncurrent	(34,908)	(62,941)
Natural gas collars	Derivative contracts-noncurrent	(238)	—
Interest rate swaps	Derivative contracts-noncurrent	(7,687)	(1,219)
Total net derivative contracts		$(222,554)	$ 37,854

Refer to Note 3 for additional discussion on the fair value measurement of the Company's derivative contracts.

The following table summarizes the effect of the Company's derivative contracts on the accompanying consolidated statements of operations for the years ended December 31, 2010, 2009 and 2008 (in thousands):

Type of Contract	Location of Loss (Gain) Recognized in Income	Amount of Loss (Gain) Recognized in Income 2010	2009	2008
Oil and natural gas derivatives	Loss (gain) on derivative contracts	$50,872	$(147,527)	$(211,439)
Interest rate swaps	Interest expense	16,540	5,783	7,441
Total		$67,412	$(141,744)	$(203,998)

The following tables summarize the cash settlements and valuation gains and losses on our commodity derivative contracts and interest rate swaps for the years ended December 31, 2010, 2009 and 2008 (in thousands):

Oil and Natural Gas Derivatives	Year Ended December 31, 2010	2009	2008
Realized (gain) loss(1)	$(224,337)	$(348,022)	$ 12,981
Unrealized loss (gain)	275,209	200,495	(224,420)
Loss (gain) on commodity derivative contracts	$ 50,872	$(147,527)	$(211,439)

Interest Rate Swaps	Year Ended December 31, 2010	2009	2008
Realized loss (gain)	$ 8,145	$6,229	$(1,304)
Unrealized loss (gain)	8,395	(446)	8,745
Loss on interest rate swaps	$16,540	$5,783	$ 7,441

(1) Includes $114.4 million of realized gains for the year ended December 31, 2010, related to settlements of commodity derivative contracts with contractual maturities after the quarterly period in which they were settled. There were no commodity derivative contracts settled prior to the contractual maturity during 2009 or 2008.

At December 31, 2010, the Company's open oil and natural gas commodity derivative contracts consisted of the following:

Oil

Period and Type of Contract	Notional (in MBbl)	Weighted Avg. Fixed Price
January 2011 — March 2011		
Price swap contracts	1,953	$86.20
April 2011 — June 2011		
Price swap contracts	1,975	$86.20
July 2011 — September 2011		
Price swap contracts	2,180	$85.96
October 2011 — December 2011		
Price swap contracts	2,180	$85.96
January 2012 — March 2012		
Price swap contracts	2,275	$87.18
April 2012 — June 2012		
Price swap contracts	2,366	$87.10
July 2012 — September 2012		
Price swap contracts	2,422	$87.08
October 2012 — December 2012		
Price swap contracts	2,484	$87.04
January 2013 — March 2013		
Price swap contracts	1,328	$88.77
April 2013 — June 2013		
Price swap contracts	1,342	$88.77
July 2013 — September 2013		
Price swap contracts	1,357	$88.77
October 2013 — December 2013		
Price swap contracts	1,357	$88.77

Natural Gas

Period and Type of Contract	Notional (MMcf)(1)	Weighted Avg. Fixed Price	Collar Range
January 2011 — March 2011			
Price swap contracts	14,270	$ 4.66	
Basis swap contracts	25,650	$(0.47)	
April 2011 — June 2011			
Price swap contracts	13,650	$ 4.69	
Basis swap contracts	25,935	$(0.47)	
July 2011 — September 2011			
Price swap contracts	15,979	$ 4.70	
Basis swap contracts	26,220	$(0.47)	
October 2011 — December 2011			
Price swap contracts	15,671	$ 4.71	
Basis swap contracts	26,220	$(0.47)	
January 2012 — March 2012			
Price swap contracts	14,105	$ 5.15	
Basis swap contracts	28,210	$(0.55)	
April 2012 — June 2012			
Price swap contracts	12,740	$ 5.14	
Basis swap contracts	28,210	$(0.55)	
July 2012 — September 2012			
Basis swap contracts	28,520	$(0.55)	
Collars	201	—	4.00 -6.20
October 2012 — December 2012			
Basis swap contracts	28,520	$(0.55)	
Collars	201	—	4.00 -6.20
January 2013 — March 2013			
Basis swap contracts	3,600	$(0.46)	
Collars	212	—	4.00 -7.15
April 2013 — June 2013			
Basis swap contracts	3,640	$(0.46)	
Collars	214	—	4.00 -7.15
July 2013 — September 2013			
Basis swap contracts	3,680	$(0.46)	
Collars	216	—	4.00 -7.15
October 2013 — December 2013			
Basis swap contracts	3,680	$(0.46)	
Collars	216	—	4.00 -7.15
January 2014 — March 2014			
Collars	231	—	4.00 -7.78
April 2014 — June 2014			
Collars	234	—	4.00 -7.78
July 2014 — September 2014			
Collars	236	—	4.00 -7.78
October 2014 — December 2014			
Collars	236	—	4.00 -7.78
January 2015 — March 2015			
Collars	249	—	4.00 -8.55
April 2015 — June 2015			
Collars	252	—	4.00 -8.55
July 2015 — September 2015			
Collars	255	—	4.00 -8.55
October 2015 — December 2015			
Collars	255	—	4.00 -8.55

(1) Assumes ratio of 1:1 for Mcf to MMBtu.

17. 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. The 2010 annual 401(k) deferral limit for employees under age 50 was $16,500. Employees turning age 50 or over in 2010 could defer up to $22,000 in 2010. The Company makes matching contributions to the plan equal to 100% on the first 15% of employee deferred wages. All matching contributions are made with Company stock. In 2008, the Company satisfied its matching obligations related to employee contributions from 2007 through transfers of treasury stock. See Note 22. For 2010, 2009 and 2008, the Company satisfied its matching obligations related to employee contributions with cash purchases of Company stock. For 2010, 2009 and 2008, retirement plan expense was approximately $8.7 million, $7.4 million and $7.8 million, respectively.

Deferred Compensation Plan. Effective February 1, 2007 the Company established a non-qualified deferred compensation plan that allows eligible highly compensated employees to elect to defer income exceeding the IRS annual limitations on qualified 401(k) retirement plans. The Company makes matching contributions on non-qualified contributions up to a maximum of 15% of employee gross earnings. For 2010, 2009 and 2008, employer contributions were approximately $2.8 million, $2.5 million and $1.6 million, respectively.

Any assets placed in trust by the Company to fund future obligations of the Company's non-qualified deferred compensation plan are subject to the claims of creditors in the event of insolvency or bankruptcy, and participants are general creditors of the Company as to their deferred compensation in the plan.

18. Income Taxes

The (benefit) provision for income taxes consisted of the following components for the years ended December 31 (in thousands):

	Year Ended December 31,		
	2010	2009	2008
Current:			
Federal	$ (732)	$(4,413)	$ 4,537
State	1,552	(4,303)	4,665
	820	(8,716)	9,202
Deferred:			
Federal	(434,117)	—	(46,180)
State	(13,383)	—	(1,350)
	(447,500)	—	(47,530)
Total (benefit) provision	(446,680)	(8,716)	(38,328)
Less: income tax provision attributable to noncontrolling interest	115	—	—
Total (benefit) provision attributable to SandRidge Energy, Inc.	$(446,795)	$(8,716)	$(38,328)

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

	Year Ended December 31,		
	2010	2009	2008
Computed at federal statutory rate	$ (89,640)	$(624,507)	$(517,863)
State taxes, net of federal benefit	1,659	(14,265)	(12,153)
Non-deductible expenses	5,507	1,905	967
Stock-based compensation	9,384	5,941	—
Other	4,131	(19,098)	204
Change in valuation allowance	69,664	641,308	490,517
Valuation allowance release	(447,500)	—	—
Total (benefit) provision for income taxes	$(446,795)	$ (8,716)	$ (38,328)

Deferred income taxes are provided to reflect the future tax consequences of temporary differences between the tax basis of assets and liabilities and their reported amounts in the financial statements. Deferred tax assets are reduced by a valuation allowance when a determination is made that it is more likely than not that some or all of the deferred assets will not be realized based on the weight of all available evidence. As of December 31, 2008, the Company determined it was appropriate to record a full valuation allowance against its net deferred tax asset. The Company continued to have a full valuation allowance against its net deferred tax asset for the years ended December 31, 2010 and 2009. During the year ended December 31, 2010, the Company recorded a net deferred tax liability associated with the Arena Acquisition, which resulted in the Company releasing a portion of the previously recorded valuation allowance. The partial release of the valuation allowance was based on management's assessment that it is more likely than not that the Company will realize a benefit from more of its existing deferred tax assets as the Arena deferred tax liabilities are available to offset the reversal of the Company's deferred tax assets. Although the Company continued to have a full valuation allowance against its net deferred tax asset at December 31, 2010, the release of a portion of the valuation allowance resulted in an income tax benefit of $447.5 million for the year ended December 31, 2010.

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

	December 31,	
	2010	2009
Deferred tax liabilities:		
Derivative contracts	$ —	$ 13,627
Investment in partnerships	3,540	3,770
Total deferred tax liabilities	3,540	17,397
Deferred tax assets:		
Property, plant and equipment	251,106	873,096
Derivative contracts	71,767	—
Allowance for doubtful accounts	1,192	787
Net operating loss carryforwards	374,296	220,240
Litigation settlement	4,392	—
Compensation and benefits	12,799	9,823
Alternative minimum tax credits and other carryforwards	16,828	3,025
Asset retirement obligation	42,805	39,681
Other	4,052	2,570
Total deferred tax assets	779,237	1,149,222
Valuation allowance	(775,697)	(1,131,825)
Net deferred tax liability	$ —	$ —

As of December 31, 2010, the Company had approximately $12.2 million of alternative minimum tax credits available that do not expire. In addition, the Company had approximately $1,017.9 million of federal net operating loss carryovers that expire during the years 2023 through 2030. Excess tax benefits of approximately $13.0 million associated with the vesting of restricted stock awards are included in the federal net operating loss carryovers, but will not be recognized as a tax benefit recorded to additional paid-in capital until realized.

IRC Section 382 addresses company ownership changes and specifically limits the utilization of certain deductions and other tax attributes on an annual basis following an ownership change. The Company experienced an ownership change within the meaning of IRC Section 382 on December 31, 2008. The ownership change subjected certain of the Company's tax attributes, including $307.9 million of federal net operating loss carryforwards, to the IRC Section 382 limitation. The Company experienced a subsequent ownership change within the meaning of IRC Section 382 on July 16, 2010 as a result of the Arena Acquisition. The Company expects a more restrictive limitation on certain of its tax attributes as a result of the July 16, 2010 ownership change than with the December 31, 2008 ownership change. The more restrictive limitation would apply not only to the $307.9 million of federal net operating loss carryforwards and certain other tax attributes existing at December 31, 2008 but also to the net operating losses of approximately $488.8 million and certain other tax attributes generated during the period from January 1, 2009 through July 16, 2010. The subsequent limitation could result in a material amount of the loss carryforwards existing at July 16, 2010 expiring unused. Arena also experienced an ownership change on July 16, 2010 as a result of its acquisition by the Company. This ownership change is expected to result in a limitation on Arena's net operating loss carryforwards available to the Company. None of the limitations discussed above resulted in a current federal tax liability at December 31, 2010 and 2009.

During the year ended December 31, 2010, the Company established a liability of approximately $1.5 million for unrecognized tax benefits. If recognized, approximately $0.9 million, net of federal tax expense, would be recorded as a reduction of income tax expense and would affect the effective tax rate. The Company did not have a liability relating to uncertain tax positions at December 31, 2009.

Consistent with the Company's policy to record interest and penalties on income taxes as a component of the income tax provision, the Company has included $0.1 million of accrued gross interest with respect to unrecognized tax benefits in its consolidated statement of operations for the year ended December 31, 2010. The Company did not have an accrued liability for interest and penalties relating to uncertain tax positions at December 31, 2009.

The Company's only taxing jurisdiction is the United States (federal and state). The Company's tax years 2007 to present remain open for federal examination. Additionally, various tax years remain open for certain acquired entities beginning with tax year 2003 due to federal net operating loss carryforwards. The number of years open for state tax audits varies, depending on the state, but are generally from three to five years. Currently, several examinations are in progress. The Company does not anticipate that any federal or state audits will have a significant impact on the Company's results of operations or financial position. In addition, the Company does not expect resolution of any uncertain tax positions that would result in a significant increase or decrease to the amount of unrecognized tax benefits during the next twelve months.

For the year ended December 31, 2010, income tax refunds, net of payments, were approximately $1.5 million, compared to income tax payments, net of refunds of $2.9 million, for the year ended December 31, 2009.

19. Earnings (Loss) Per Share

Basic earnings per share are computed using the weighted average number of common shares outstanding during the period. Diluted earnings per share are computed using the weighted average shares outstanding during the period, but also include the dilutive effect of awards of restricted stock and outstanding convertible preferred 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):

	2010	2009	2008
Weighted average basic common shares outstanding	291,869	175,005	155,619
Effect of dilutive securities:			
Restricted stock	5,057	—	—
Convertible perpetual preferred stock	18,423	—	—
Weighted average diluted common and potential common shares outstanding	315,349	175,005	155,619

For the years ended December 31, 2009 and 2008, restricted stock awards covering approximately 2.8 million and 1.5 million shares, respectively, were excluded from the computation of loss per share because their effect would have been antidilutive.

In computing diluted earnings per share, the Company evaluated the if-converted method with respect to its outstanding 8.5% convertible perpetual preferred stock and 6.0% convertible perpetual preferred stock for the years ended December 31, 2010 and 2009, and with respect to its then outstanding redeemable convertible preferred stock for the year ended December 31, 2008. The 7.0% convertible perpetual preferred stock issued in November 2010 was not included in the evaluation of the if-converted method for the year ended December 31, 2010, as the shares were not convertible by the holders into shares of the Company's common stock until February 15, 2011. See Note 22 for discussion of the Company's convertible perpetual preferred stock. Under the if-converted 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. For the year ended December 31, 2010, the Company determined the if-converted method was more dilutive with respect to its 6.0% convertible perpetual preferred stock, but not more dilutive with respect to its 8.5% convertible perpetual preferred stock. As a result, the Company did not include the $12.0 million of 6.0% preferred stock dividends, but did include the 8.5% preferred stock dividends in the determination of income available to common stockholders. For the years ended December 31, 2009 and 2008, the Company determined the if-converted method was not more dilutive and included preferred stock dividends in the determination of income available to common stockholders.

20. Commitments and Contingencies

Operating Leases. The Company has obligations under noncancelable operating leases, primarily for office space and equipment used in drilling and services activities. Total rental expense under operating leases for the years ended December 31, 2010, 2009 and 2008 was approximately $2.6 million, $3.2 million and $2.4 million, respectively.

Future minimum lease payments under noncancelable operating leases (with initial lease terms exceeding one year) as of December 31, 2010 were as follows (in thousands):

Years ending December 31:	
2011	$1,136
2012	424
2013	268
2014	112
2015	27
	$1,967

Rig Commitments. The Company has contracts with third-party drilling rig operators for the use of their rigs at specified day or footage rates. These commitments are not recorded in the consolidated balance sheets. Minimum future commitments as of December 31, 2010 were $19.0 million for 2011.

Firm Transportation. The Company has subscribed firm gas transportation service under two Transportation Service Agreements ("TSA"). The TSA terms run through 2012 on the Oasis Pipeline and through 2018 on the Midcontinent Express Pipeline. These commitments are not recorded in the consolidated balance sheets. Under the terms of the TSAs, the Company is obligated to pay a demand charge and in exchange, obtains the right to flow natural gas production through these pipelines to more competitive marketing areas. The amounts of the required payments for firm transportation as of December 31, 2010 were as follows (in thousands):

Years ending December 31:	
2011	$ 20,075
2012	20,130
2013	16,973
2014	11,315
2015	11,315
Thereafter	33,976
	$113,874

Gas Gathering Agreement. In conjunction with the sale of the gathering and compression assets located in the Piñon Field in West Texas, the Company entered into a gas gathering agreement. Under the gas gathering agreement, the Company has dedicated its West Texas acreage for priority gathering services over a period of 20 years and the Company will pay a fee that was negotiated at arms' length for such services. Pursuant to the gas gathering agreement, the base fee can be reduced if certain criteria are met. The table below presents the base fee contractual obligations under this agreement as of December 31, 2010 (in thousands).

Years ending December 31:	
2011	$ 33,780
2012	42,814
2013	42,634
2014	42,360
2015	42,153
Thereafter	225,678
	$429,419

Gas Throughput Agreements. The Company has gas throughput agreements in place for the use of various natural gas pipelines. Included in these agreements are fixed fees the Company is obligated to pay in exchange for the right to flow natural gas production through these pipelines. The table below presents the contractual obligations under these agreements as of December 31, 2010 (in thousands).

Years ending December 31:	
2011	$ 9,307
2012	9,307
2013	9,308
2014	7,994
	$35,916

CO_2 Purchase Commitment. The Company has a commitment in place to purchase CO_2 for use in certain tertiary oil recovery operations. The table below presents the contractual obligations under this agreement as of December 31, 2010 (in thousands).

Years ending December 31:	
2011	$12,410
2012	12,444
2013	10,336
	$35,190

Treating Agreement. In conjunction with the Century Plant construction agreement, the Company entered into a 30-year treating agreement with Occidental for CO_2 to be removed from the Company's delivered production volumes. Under the treating agreement, the Company is required to deliver certain CO_2 volumes annually. If the Company does not meet the CO_2 volume requirements, the Company will have to pay a fee for any volume shortfalls.

Sponsorship Agreement. The Company has three years remaining under a five-year sponsorship agreement for advertising and promotional activities related to the Oklahoma City Thunder basketball team. See Note 23 for additional information.

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 other legal proceedings which, individually or in the aggregate, could have a material effect on the financial condition, operations or cash flows of the Company.

On or about June 27, 2008, there was a fire at the Company's Grey Ranch Plant. The Company, as owner of the plant, recovered approximately $18.7 million from its property insurance carrier for damages caused by the fire. At the time of the fire, the plant was operated by Southern Union Gas Services, Ltd. ("Southern Union Gas"). On June 4, 2010, the Company's property insurance carrier filed a lawsuit (the "lawsuit") against Southern Union Gas and its parent, Southern Union Company (together with Southern Union Gas, "Southern Union") seeking recovery for amounts paid under the policy. Southern Union, in turn, has tendered an indemnity request to Grey Ranch Plant, L.P., of which the Company is a 50% owner. Grey Ranch Plant, L.P. has not accepted or acknowledged any responsibility to indemnify Southern Union. To the extent the Company, as a 50% owner of Grey Ranch Plant, L.P., is required to fund any indemnification of Southern Union, it will pursue coverage for such a liability under its general liability insurance policy. An estimate of reasonably possible losses associated with this claim cannot be made at this time. The Company has not established any reserves relating to this claim.

On February 14, 2011, Aspen Pipeline, II, L.P. filed a complaint in the District Court of Harris County, Texas against Arena Resources, Inc. and SandRidge Energy, Inc. claiming damages based upon alleged representations by Arena in connection with the construction by Aspen of a natural gas pipeline in West Texas. The plaintiff seeks damages that include the construction cost of the pipeline, which it claims approach $90.0 million. The Company intends to defend this lawsuit vigorously and, believes the plaintiff's claims are without merit. This case is in the early stages and, accordingly, an estimate of reasonably possible losses associated with this claim cannot be made at this time. The Company has not established any reserves relating to this claim.

21. Redeemable Convertible Preferred Stock

The Company's redeemable convertible preferred stock, issued in November 2006, entitled each holder to quarterly cash dividends at the annual rate of 7.75% of the accreted value, or $210 per share, of their redeemable convertible preferred stock. Each share of redeemable convertible preferred stock was initially convertible into 10.0 shares, and ultimately convertible into 10.2 shares, of common stock at the option of the holder, subject to certain anti-dilution adjustments.

During March 2008, holders of 339,823 shares of the Company's redeemable convertible preferred stock elected to convert those shares into 3,465,593 shares of the Company's common stock. Additionally, during May 2008, the Company converted the remaining outstanding 1,844,464 shares of its redeemable convertible preferred stock into 18,810,260 shares of its common stock as permitted under the terms of the redeemable convertible preferred stock. These conversions resulted in increases to additional paid-in capital totaling $452.2 million, which represents the difference between the par value of the common stock issued and the carrying value of the redeemable convertible shares converted. The Company also recorded charges to retained earnings totaling $7.2 million in accelerated accretion expense related to the converted redeemable convertible preferred shares. Prorated dividends totaling $0.5 million for the period from May 2, 2008 to the date of conversion (May 7, 2008) were paid to the holders of the converted shares on May 7, 2008. On and after the conversion date, dividends ceased to accrue and the rights of common unit holders to exercise outstanding warrants to purchase redeemable convertible preferred shares terminated. A summary of dividends declared and paid during 2008 on the redeemable convertible preferred stock is as follows (in thousands, except per share data):

Declared	Dividend Period	Dividends per Share	Total	Payment Date
December 16, 2007	November 2, 2007 — February 1, 2008	$4.10	$ 8,956	February 15, 2008
March 7, 2008	February 2, 2008 — May 1, 2008	4.01	8,095	(1)
May 7, 2008	May 2, 2008 — May 7, 2008	4.01	501	May 7, 2008

(1) Includes $0.6 million of prorated dividends paid to holders of redeemable convertible preferred shares at the time their shares converted to common stock in March 2008. The remaining dividends of $7.5 million were paid during May 2008.

Approximately $8.6 million in paid and unpaid dividends on the redeemable convertible preferred stock was included in the Company's earnings per share calculations for the year ended December 31, 2008, as presented in the accompanying consolidated statement of operations. No shares of redeemable convertible preferred stock were outstanding during the years ended December 31, 2010 and 2009.

22. Equity

Preferred Stock

The following table presents information regarding the Company's preferred stock (in thousands):

	December 31, 2010	December 31, 2009
Shares authorized	50,000	50,000
Shares outstanding at end of period:		
8.5% Convertible perpetual preferred stock	2,650	2,650
6.0% Convertible perpetual preferred stock	2,000	2,000
7.0% Convertible perpetual preferred stock	3,000	—

The Company is authorized to issue 50,000,000 shares of preferred stock, $0.001 par value, of which 7,650,000 shares are designated as convertible perpetual preferred stock at December 31, 2010. All of the outstanding shares of the Company's convertible perpetual preferred stock were issued in private transactions and none of these shares is listed on a stock exchange.

8.5% Convertible perpetual preferred stock. The Company's 8.5% convertible perpetual preferred stock was issued in January 2009. Net proceeds from the sale of 2,650,000 shares of 8.5% convertible perpetual preferred stock totaled $243.3 million after deducting offering expenses of approximately $8.6 million and were used to repay amounts outstanding under the senior credit facility and for general corporate purposes. Each share of 8.5% convertible perpetual preferred stock has a liquidation preference of $100.00 and is convertible at the holder's option at any time initially into approximately 12.4805 shares of the Company's common stock based on an initial conversion price of $8.01, subject to adjustments upon the occurrence of certain events. Each holder of the convertible perpetual preferred stock is entitled to an annual dividend of $8.50 per share to be paid semi-annually in cash, common stock or a combination thereof, at the Company's election. Dividend payments were paid in cash in February and August 2010. Approximately $22.5 million in dividends ($14.1 million paid and $8.4 million unpaid) and $8.4 million in dividends (all unpaid) on the 8.5% convertible perpetual preferred stock have been included in the Company's earnings per share calculations for the years ended December 31, 2010 and 2009, respectively, as presented in the accompanying consolidated statements of operations. The 8.5% convertible perpetual preferred stock is not redeemable by the Company at any time. After February 20, 2014, the Company may cause all outstanding shares of the convertible perpetual preferred stock to convert automatically into common stock at the then-prevailing conversion rate if certain conditions are met.

6.0% Convertible perpetual preferred stock. The Company's 6.0% convertible perpetual preferred stock was issued in December 2009. Net proceeds from the sale of 2,000,000 shares of 6.0% convertible perpetual preferred stock totaled $199.9 million and were used to fund a portion of the purchased oil and natural gas properties from Forest and for general corporate purposes. Each share of the 6.0% convertible perpetual preferred stock has a liquidation preference of $100.00 and is entitled to an annual dividend of $6.00 payable semi-annually in cash, common stock or any combination thereof, at the Company's election. The first dividend payment was paid in cash in July 2010. Approximately $12.0 million in dividends ($6.0 million paid and $6.0 million unpaid) and $0.4 million (all unpaid) on the 6.0% convertible perpetual preferred stock have been included in the Company's earnings per share calculations for the years ended December 31, 2010 and 2009, respectively, as presented in the accompanying consolidated statements of operations. The 6.0% convertible perpetual preferred stock is not redeemable by the Company at any time. Each share is initially convertible into 9.21 shares of the Company's common stock, at the holder's option based on an initial conversion price of $10.86 and subject to customary adjustments in certain circumstances. Five years after their issuance, all outstanding shares of the convertible preferred stock will be converted automatically into shares of the Company's common stock at the then-prevailing conversion price as long as all dividends accrued at that time have been paid.

7.0% Convertible perpetual preferred stock. The Company's 7.0% convertible perpetual preferred stock was issued in November 2010. Net proceeds from the sale of 3,000,000 shares of the 7.0% convertible perpetual preferred stock were approximately $290.7 million, after deducting offering expenses and discounts to the initial purchasers. The Company used the net proceeds to repay outstanding borrowings under the senior credit facility and to fund capital expenditures. Each share of the 7.0% convertible preferred stock has a liquidation preference of $100.00 per share and will be convertible, at the holder's option, at any time on or after February 15, 2011, initially into approximately 12.8791 shares of the Company's common stock based on an initial conversion price of $7.76 per share. The annual dividend on each share of the 7.0% convertible preferred stock will be $7.00 and will be payable semi-annually, in cash, common stock or a combination thereof, at the Company's election. Approximately $2.9 million in unpaid dividends on the 7.0% convertible perpetual preferred stock has been included in the Company's earnings per share calculations for the year ended December 31, 2010 as presented in the accompanying consolidated statements of operations. The 7.0% convertible perpetual preferred stock is not redeemable by the Company at any time. After November 20, 2015, the Company may cause all outstanding shares of the 7.0% convertible perpetual preferred stock to convert automatically into common stock at the then-prevailing conversion rate if certain conditions are met.

Common Stock

The following table presents information regarding the Company's common stock (in thousands):

	December 31,	
	2010	2009
Shares authorized	800,000	400,000
Shares outstanding at end of period	406,360	208,715
Shares held in treasury	470	1,866

During March 2008, the Company issued 3,465,593 shares of common stock upon the conversion of 339,823 shares of its redeemable convertible preferred stock. In May 2008, the Company converted the remaining 1,844,464 outstanding shares of its redeemable convertible preferred stock into 18,810,260 shares of its common stock as permitted under the terms of the redeemable convertible preferred stock. See additional discussion at Note 21.

In April 2009, the Company completed a registered underwritten offering of 14,480,000 shares of its common stock, including 2,280,000 shares of common stock acquired by the underwriters from the Company to cover over-allotments. Net proceeds to the Company from the offering were approximately $107.6 million, after deducting offering expenses of approximately $2.4 million, and were used to repay a portion of the amount outstanding under the senior credit facility and for general corporate purposes.

In December 2009, the Company completed a registered underwritten public offering of 25,600,000 shares of its common stock, including 3,600,000 shares of common stock acquired by the underwriters from the Company to cover over-allotments. Net proceeds from the offering were approximately $217.2 million after deducting offering expenses of approximately $9.4 million. The net proceeds were used to fund the purchase of oil and natural gas properties from Forest and for general corporate purposes.

In July 2010, in conjunction with stockholder approval of the issuance of shares of Company common stock in connection with the Company's acquisition of Arena, the Company's stockholders approved an amendment to the Company's certificate of incorporation to increase the number of authorized shares of common stock from 400.0 million shares to 800.0 million shares. See Note 2 for further discussion regarding the Arena Acquisition.

In December 2010, the Company issued 1,788,909 shares of Company common stock (of which 491,950 shares were newly issued and 1,296,959 shares were issued from treasury stock) as part of the settlement of a dispute with certain working interest owners. The issuance of the 491,950 shares resulted in an addition to the Company's additional paid-in capital of $3.4 million based on the market value of the common stock on the day of issuance less par value. See additional discussion, including the effects on treasury stock and additional paid-in capital, below.

Treasury Stock

The Company makes required tax payments on behalf of employees when their restricted stock awards vest and then withholds a number of vested shares of common stock having a value on the date of vesting equal to the tax obligation. As a result of such transactions, the Company withheld approximately 845,608 shares having a total value of $6.3 million, 167,009 shares having a total value of $1.5 million, and 80,724 shares having a total value of $3.6 million during the years ended December 31, 2010, 2009 and 2008, respectively. These shares were accounted for as treasury stock. In December 2010, the Company's Board of Directors elected to retire all shares currently held as treasury and any shares of common stock purchased into treasury in the future to satisfy tax withholding obligations related to the vesting of restricted stock awards that are forfeited under the Company's incentive compensation plans, excluding shares of Company common stock held as assets in a trust for the Company's non-qualified deferred compensation plan. Retirement of the treasury shares in December 2010 resulted in a reduction to additional paid-in capital equal to the historical cost of the treasury shares, or approximately $11.3 million.

Any shares of Company common stock held as assets in a trust for the Company's non-qualified deferred compensation plan are accounted for as treasury shares. These shares are not included as outstanding shares of common stock in this report. For corporate purposes and for purposes of voting at Company stockholder meetings, these shares are considered outstanding and have voting rights, which are exercised by the Company.

In February 2008, the Company transferred 184,484 shares of its treasury stock into an account established for the benefit of the Company's 401(k) Plan. The transfer was made in order to satisfy the Company's $5.0 million accrued payable to match employee contributions made to the plan during 2007. The historical cost of the shares transferred totaled approximately $2.4 million and resulted in an increase to the Company's additional paid-in capital of approximately $2.6 million.

In December 2010, the Company finalized the settlement of a dispute with certain working interest owners under two joint operating agreements. As part of the settlement, the Company issued the working interest owners a total of 1,788,909 shares of Company common stock. As noted above, 491,950 of such shares were newly issued and the remaining 1,296,959 shares were issued from treasury stock. The historical cost of the treasury shares issued was approximately $14.0 million. The difference between the market price of these shares at the time of issuance and the historical cost resulted in a decrease of the Company's additional paid-in capital of approximately $5.2 million.

Equity Compensation

The Company awards restricted common stock under incentive compensation plans that vest over specified periods of time, subject to certain conditions. 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. Unvested restricted stock awards are included in the Company's outstanding shares of common stock.

Equity compensation provided to employees directly involved in oil and natural gas exploration and development activities is capitalized to the Company's oil and natural gas properties. Equity compensation not capitalized is reflected in general and administrative expenses, production expenses, midstream and marketing expenses and drilling and services expenses in the consolidated statements of operations. For the years ended December 31, 2010 and 2009, the Company recognized equity compensation expense of $37.7 million and $22.8 million, net of $5.6 million and $4.3 million capitalized, respectively, related to restricted common stock. For the year ended December 31, 2008, the Company recognized equity compensation expense of $18.8 million, related to restricted common stock. There was no equity compensation capitalized in 2008.

Effective June 5, 2009, the Company adopted the SandRidge Energy, Inc. 2009 Incentive Plan (the "2009 Incentive Plan"). Under the terms of the 2009 Incentive Plan, the Company may grant stock options, stock appreciation rights, shares of restricted stock, restricted stock units and other forms of awards based on the value (or increase in the value) of shares of the common stock of the Company for up to 12,000,000 shares of common stock. The 2009 Incentive Plan also permits cash incentive awards. Consistent with its other incentive plans, the Company intends for shares of restricted stock to be the primary form of awards granted under the 2009 Incentive Plan.

Restricted stock activity for the years ended December 31, 2008, 2009 and 2010 was as follows (shares in thousands):

	Number of Shares	Weighted-Average Grant Date Fair Value
Unvested restricted shares outstanding at December 31, 2007	1,927	$19.25
Granted	1,638	$41.15
Vested	(440)	$30.47
Canceled	(132)	$19.41
Unvested restricted shares outstanding at December 31, 2008	2,993	$30.71
Granted	3,531	$ 8.34
Vested	(800)	$29.43
Canceled	(402)	$20.97
Unvested restricted shares outstanding at December 31, 2009	5,322	$16.80
Granted(1)	6,210	$ 7.87
Vested(1)	(1,613)	$18.28
Canceled	(443)	$12.74
Unvested restricted shares outstanding at December 31, 2010	9,476	$10.89

(1) Excludes 743,119 restricted shares from stock awards assumed in the Arena Acquisition. All of these awards had vested as of December 31, 2010.

As of December 31, 2010, there was approximately $76.3 million of unrecognized compensation cost related to unvested restricted stock awards, which is expected to be recognized over a weighted average period of 2.8 years.

Noncontrolling Interest

Noncontrolling interests in certain of the Company's subsidiaries and a variable interest entity for which the Company is the primary beneficiary (see Note 11) represent third-party ownership interests in the consolidated entity and are included as a component of equity in the consolidated balance sheets and consolidated statement of changes in equity as required by 'ASC 810.

The following table presents a reconciliation of the activity for noncontrolling interest in entities included in the consolidated results of the Company for the years ended December 31, 2010, 2009 and 2008.

	2010	2009	2008
Beginning balance, January 1	$10,052	$ 30	$ 4,672
Distributions to noncontrolling interest owners	(3,515)	(26)	(5,497)
Contributions from noncontrolling interest owners	306	—	—
Consolidation of Grey Ranch Plant L.P.	—	7,790	—
Net income attributable to noncontrolling interest	4,445	2,258	855
Ending balance, December 31	$11,288	$10,052	$ 30

23. Related Party Transactions

The Company enters into transactions in the ordinary course of business with certain of its stockholders and other related parties. These transactions primarily consist of purchases relating to drilling and completion activities, gas treating services and drilling equipment and sales of oil field services, equipment and natural gas. Following is a summary of significant transactions with such related parties for years ended December 31 (in thousands):

	2010	2009	2008
Sales to and reimbursements from related parties	$15,713	$ 7,304	$90,170
Purchases of services from related parties	$ 165	$21,745	$59,951

	December 31,	
	2010	2009
Accounts receivable due from related parties	$1,702	$ 64
Accounts payable due to related parties	$ 800	$860

Larclay, L.P. Until April 15, 2009, Lariat and its partner CWEI each owned a 50% interest in Larclay, a limited partnership, and, until such time, Lariat operated the rigs owned by Larclay. On April 15, 2009, Lariat completed an assignment to CWEI of Lariat's 50% equity interest in Larclay pursuant to the terms of the Larclay Assignment entered into between Lariat and CWEI on March 13, 2009. Pursuant to the Larclay Assignment, Lariat assigned all of its right, title and interest in and to Larclay to CWEI effective April 15, 2009, and CWEI assumed all of the obligations and liabilities of Lariat relating to Larclay. For the period from January 1, 2009 through April 15, 2009, sales to and reimbursements and purchases of services from Larclay were $3.1 million and $1.8 million, respectively. For the year ended December 31, 2008, sales to and reimbursements and purchases of services from Larclay were $42.8 million and $34.7 million, respectively.

In 2008, the Company purchased certain working interests and related reserves in Company wells owned by its Chairman and Chief Executive Officer and certain of his affiliates. The purchase price was $67.3 million. See Note 2.

Oklahoma City Thunder Agreements. The Company's Chairman and Chief Executive Officer owns a minority interest in a limited liability company which owns and operates the Oklahoma City Thunder, a National Basketball Association team playing in Oklahoma City, where the Company is headquartered. The Company is party to a five-year sponsorship agreement whereby it pays approximately $3.3 million per year for advertising and promotional activities related to the Oklahoma City Thunder. Additionally, the Company entered into an agreement to license a suite at the arena where the Oklahoma City Thunder plays its home games. Under this four-year agreement, the Company will pay an annual license fee of $0.2 million. Amounts related to these agreements are not included in the tables above.

24. Subsequent Events

Events occurring after December 31, 2010 were evaluated to ensure that any subsequent events that met the criteria for recognition and/or disclosure in this report have been included.

Sale of Wolfberry Assets. On January 6, 2011, the Company sold its Wolfberry assets in the Permian Basin for approximately $155.0 million, subject to post-closing adjustments. This asset sale was accounted for as an adjustment to the full cost pool with no gain or loss recognized.

Litigation. On February 14, 2011, Aspen Pipeline, II, L.P. filed a complaint against Arena and the Company. See Note 20 for additional discussion of this claim.

Senior Credit Facility Amendment. On February 23, 2011, the senior credit facility was amended to, among other things, (a) exclude from the calculation of Consolidated Net Income the net income (or loss) of a Royalty Trust, except to the extent of cash distributions received by the Company, (b) establish that an investment in a Royalty Trust and dispositions to, and of interests in, Royalty Trusts are permitted, (c) clarify that a Royalty Trust is not a Subsidiary, (d) allow the Company to net against its calculation of Consolidated Funded Indebtedness cash balances exceeding $10.0 million in the event no loans are outstanding under the senior credit facility at that time, and (e) establish that, for any fiscal quarter prior to March 31, 2012, if its Senior Secured Leverage Ratio is less than 1.5:1.0 then the Company's Consolidated Leverage Ratio is negated. Terms capitalized in the preceding sentence have the meaning given to them in the senior credit facility, as amended.

Sale of New Mexico Assets. On February 24, 2011, the Company executed a Purchase and Sales Agreement under which it agreed to sell properties in Lea County and Eddy County in New Mexico for $200.0 million. The Company expects the transaction, which is subject to customary closing conditions, to close in April 2011.

25. Business Segment Information

The Company has three business segments: exploration and production, drilling and oil field services and midstream gas services. These segments represent the Company's three main business units, each offering different products and services. The exploration and production segment is engaged in the acquisition, development 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, treating and selling of natural gas. The All Other column in the tables below includes items not related to the Company's reportable segments, including the Company's CO_2 gathering and sales operations and corporate operations.

As further discussed in Note 26, SandRidge Energy, Inc., the parent company, contributed its oil and natural gas related assets and liabilities to one of its wholly owned subsidiaries effective as of May 1, 2009. As a result, the financial information of SandRidge Energy, Inc. is included in the All Other column in the tables below, which is consistent with management's evaluation of the business segments. The operations of SandRidge Energy, Inc. were previously included in the exploration and production segment. All periods presented below reflect this change in presentation.

SandRidge Energy, Inc., and Subsidiaries
Notes to Consolidated Financial Statements—(continued)

Management evaluates the performance of the Company's business segments based on operating income, which is defined as segment 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):

	Exploration and Production	Drilling and Oil Field Services	Midstream Gas Services	All Other	Consolidated Total
Year Ended December 31, 2010					
Revenues	$ 779,450	$ 265,262	$ 275,071	$ 35,285	$ 1,355,068
Inter-segment revenue	(259)	(236,687)	(176,549)	(9,837)	(423,332)
Total revenues	$ 779,191	$ 28,575	$ 98,522	$ 25,448	$ 931,736
Operating income (loss)	$ 88,390	$ (9,970)	$ 3,959	$ (89,165)	$ (6,786)
Interest income (expense), net	496	(920)	(649)	(246,369)	(247,442)
Other income, net	1,251	—	625	682	2,558
Income (loss) before income taxes	$ 90,137	$ (10,890)	$ 3,935	$(334,852)	$ (251,670)
Capital expenditures(1)	$ 1,027,933	$ 31,658	$ 48,401	$ 21,661	$ 1,129,653
Depreciation, depletion and amortization	$ 278,110	$ 30,031	$ 4,030	$ 13,940	$ 326,111
At December 31, 2010					
Total assets	$ 4,612,295	$ 224,784	$ 151,598	$ 242,771	$ 5,231,448
Year Ended December 31, 2009					
Revenues	$ 457,397	$ 225,227	$ 299,580	$ 30,654	$ 1,012,858
Inter-segment revenue	(261)	(201,641)	(215,667)	(4,245)	(421,814)
Total revenues	$ 457,136	$ 23,586	$ 83,913	$ 26,409	$ 591,044
Operating loss(2)	$(1,487,914)	$ (15,166)	$ (36,989)	$ (64,955)	$(1,605,024)
Interest income (expense), net	1,121	(2,074)	(1,246)	(183,117)	(185,316)
Other income, net	4,673	—	3,365	254	8,292
Loss before income taxes	$(1,482,120)	$ (17,240)	$ (34,870)	$(247,818)	$(1,782,048)
Capital expenditures(1)	$ 555,809	$ 4,090	$ 52,425	$ 32,818	$ 645,142
Depreciation, depletion and amortization	$ 178,783	$ 28,221	$ 5,496	$ 14,392	$ 226,892
At December 31, 2009					
Total assets	$ 2,222,724	$ 229,507	$ 110,757	$ 217,329	$ 2,780,317
Year Ended December 31, 2008					
Revenues	$ 912,716	$ 434,963	$ 688,071	$ 22,791	$ 2,058,541
Inter-segment revenue	(220)	(387,972)	(483,933)	(4,602)	(876,727)
Total revenues	$ 912,496	$ 46,991	$ 204,138	$ 18,189	$ 1,181,814
Operating (loss) income	$(1,262,903)	$ (5,393)	$ 2,087	$ (71,938)	$(1,338,147)
Interest expense, net	(6,336)	(2,766)	—	(134,356)	(143,458)
Other income, net	1,171	1,015	398	268	2,852
(Loss) income before income taxes	$(1,268,068)	$ (7,144)	$ 2,485	$(206,026)	$(1,478,753)
Capital expenditures(1)	$ 1,909,078	$ 52,869	$ 160,460	$ 55,440	$ 2,177,847
Depreciation, depletion and amortization	$ 293,625	$ 42,077	$ 15,241	$ 10,422	$ 361,365

(1) On an accrual basis.

(2) The operating loss for the exploration and production segment for the years ended December 31, 2009 and 2008 includes non-cash full cost ceiling impairments of $1,693.3 million and $1,855.0 million, respectively, on the Company's oil and natural gas properties. The operating loss for the midstream gas services segment for the year ended December 31, 2009 includes a $26.1 million loss on the sale of its gathering and compression assets in the Piñon Field.

Major Customers. For the years ended 2010, 2009 and 2008, the Company had sales exceeding 10% of total revenues to the following oil and natural gas purchasers (in thousands):

	2010	
	Sales	% of Revenue
Plains Marketing, L.P.	$239,396	25.7%
ConocoPhillips Company	$109,358	11.7%

	2009	
	Sales	% of Revenue
Plains Marketing, L.P.	$120,097	20.3%

	2008	
	Sales	% of Revenue
Plains Marketing, L.P.	$124,595	10.5%

26. Condensed Consolidating Financial Information

The Company provides condensed consolidating financial information for its subsidiaries that are guarantors of its registered debt. The subsidiary guarantors are wholly owned and have, jointly and severally, unconditionally guaranteed on an unsecured basis the Company's 8.625% Senior Notes, Senior Floating Rate Notes and 8.75% Senior Notes. The subsidiary guarantees (i) rank equally in right of payment with all of the existing and future senior debt of the subsidiary guarantors; (ii) rank senior to all of the existing and future subordinated debt of the subsidiary guarantors; (iii) are effectively subordinated in right of payment to any existing or future secured obligations of the subsidiary guarantors to the extent of the value of the assets securing such obligations; and (iv) are structurally subordinated to all debt and other obligations of the subsidiaries of the guarantors who are not themselves guarantors. The Company's subsidiary guarantors guarantee payments of principal and interest under the Company's registered notes. The Company has not presented separate financial and narrative information for each of the subsidiary guarantors because it believes that such financial and narrative information would not provide any additional information that would be material in evaluating the sufficiency of the guarantees.

Effective May 1, 2009, SandRidge Energy, Inc., the parent, contributed all of its rights, title and interest in its oil and natural gas related assets and accompanying liabilities to one of its wholly owned guarantor subsidiaries, leaving it with no oil or natural gas related assets or operations.

The following condensed consolidating financial information represents the financial information of SandRidge Energy, Inc., its wholly owned subsidiary guarantors and its non-guarantor subsidiaries, prepared on the equity basis of accounting. The non-guarantor subsidiaries and a variable interest entity are included in the non-guarantor column in the tables below. The financial information may not necessarily be indicative of the financial position, results of operations or cash flows had the subsidiary guarantors operated as independent entities.

Condensed Consolidating Balance Sheets

	December 31, 2010				
	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ 1,441	$ 564	$ 3,858	$ —	$ 5,863
Accounts and notes receivable, net	1,224,500	141,530	408,015	(1,627,927)	146,118
Derivative contracts	—	5,028	—	—	5,028
Other current assets	—	13,890	4,691	—	18,581
Total current assets	1,225,941	161,012	416,564	(1,627,927)	175,590
Property, plant and equipment, net	—	4,635,747	98,118	—	4,733,865
Investment in subsidiaries	3,230,067	69,995	—	(3,300,062)	—
Goodwill	—	234,356	—	—	234,356
Other assets	50,637	37,000	—	—	87,637
Total assets	$4,506,645	$5,138,110	$514,682	$(4,927,989)	$5,231,448
LIABILITIES AND EQUITY					
Current liabilities:					
Accounts payable and accrued expenses	$ 66,539	$1,510,827	$427,483	$(1,627,927)	$ 376,922
Derivative contracts	9,007	94,402	—	—	103,409
Asset retirement obligation	—	25,360	—	—	25,360
Other current liabilities	—	37,776	991	—	38,767
Total current liabilities	75,546	1,668,365	428,474	(1,627,927)	544,458
Long-term debt	2,885,764	—	16,029	—	2,901,793
Derivative contracts	7,687	116,486	—	—	124,173
Asset retirement obligation	—	94,350	167	—	94,517
Other liabilities	1,454	17,570	—	—	19,024
Total liabilities	2,970,451	1,896,771	444,670	(1,627,927)	3,683,965
Equity	1,536,194	3,241,339	70,012	(3,300,062)	1,547,483
Total liabilities and equity	$4,506,645	$5,138,110	$514,682	$(4,927,989)	$5,231,448

	December 31, 2009				
	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ 339	$ 2,841	$ 4,681	$ —	$ 7,861
Accounts receivable, net	642,317	96,251	14,888	(647,980)	105,476
Derivative contracts	—	105,994	—	—	105,994
Other current assets	—	24,785	11,848	—	36,633
Total current assets	642,656	229,871	31,417	(647,980)	255,964
Property, plant and equipment, net	—	2,331,261	102,382	—	2,433,643
Investment in subsidiaries	1,813,887	64,827	—	(1,878,714)	—
Other assets	49,103	41,607	—	—	90,710
Total assets	$2,505,646	$2,667,566	$133,799	$(2,526,694)	$2,780,317
LIABILITIES AND EQUITY					
Current liabilities:					
Accounts payable and accrued expenses	$ 159,693	$ 641,349	$ 50,846	$ (647,980)	$ 203,908
Other current liabilities	7,080	13,624	932	—	21,636
Total current liabilities	166,773	654,973	51,778	(647,980)	225,544
Long-term debt	2,543,611	6,304	17,020	—	2,566,935
Derivative contracts	1,219	59,841	—	—	61,060
Asset retirement obligation	—	108,429	155	—	108,584
Other liabilities	—	14,099	—	—	14,099
Total liabilities	2,711,603	843,646	68,953	(647,980)	2,976,222
(Deficit) equity	(205,957)	1,823,920	64,846	(1,878,714)	(195,905)
Total liabilities and equity	$2,505,646	$2,667,566	$133,799	$(2,526,694)	$2,780,317

Condensed Consolidating Statements of Operations

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(In thousands)		
Year Ended December 31, 2010					
Total revenues	$ —	$ 894,621	$138,685	$ (101,570)	$ 931,736
Expenses:					
Direct operating expenses	—	366,947	115,912	(100,885)	381,974
General and administrative	882	176,075	3,293	(685)	179,565
Depreciation, depletion, amortization and impairment	—	319,297	6,814	—	326,111
Loss on derivative contracts	—	50,872	—	—	50,872
Total expenses	882	913,191	126,019	(101,570)	938,522
(Loss) income from operations	(882)	(18,570)	12,666	—	(6,786)
Equity earnings from subsidiaries	(10,253)	7,123	—	3,130	—
Interest expense, net	(245,284)	(1,073)	(1,085)	—	(247,442)
Other income, net	74	2,267	217	—	2,558
(Loss) income before income taxes	(256,345)	(10,253)	11,798	3,130	(251,670)
Income tax (benefit) expense	(446,910)	—	230	—	(446,680)
Net income (loss)	190,565	(10,253)	11,568	3,130	195,010
Less: net income attributable to noncontrolling interest	—	—	4,445	—	4,445
Net income (loss) attributable to SandRidge Energy, Inc.	$ 190,565	$ (10,253)	$ 7,123	$ 3,130	$ 190,565
Year Ended December 31, 2009					
Total revenues	$ 58,273	$ 498,032	$172,585	$ (137,846)	$ 591,044
Expenses:					
Direct operating expenses	27,737	262,778	156,032	(137,250)	309,297
General and administrative	15,645	82,691	2,516	(596)	100,256
Depreciation, depletion, amortization and impairment	627,478	1,295,414	11,150	—	1,934,042
(Gain) loss on derivative contracts	(237,351)	89,824	—	—	(147,527)
Total expenses	433,509	1,730,707	169,698	(137,846)	2,196,068
(Loss) income from operations	(375,236)	(1,232,675)	2,887	—	(1,605,024)
Equity earnings from subsidiaries	(1,227,164)	1,834	—	1,225,330	—
Interest expense, net	(182,009)	(2,167)	(1,140)	—	(185,316)
Other income, net	103	5,844	2,345	—	8,292
(Loss) income before income taxes	(1,784,306)	(1,227,164)	4,092	1,225,330	(1,782,048)
Income tax benefit	(8,716)	—	—	—	(8,716)
Net (loss) income	(1,775,590)	(1,227,164)	4,092	1,225,330	(1,773,332)
Less: net income attributable to noncontrolling interest	—	—	2,258	—	2,258
Net (loss) income attributable to SandRidge Energy, Inc.	$(1,775,590)	$(1,227,164)	$ 1,834	$1,225,330	$(1,775,590)

SandRidge Energy, Inc., and Subsidiaries
Notes to Consolidated Financial Statements—(continued)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(In thousands)		
Year Ended December 31, 2008					
Total revenues	$ 329,109	$ 814,934	$218,148	$(180,377)	$ 1,181,814
Expenses:					
Direct operating expenses	72,473	296,991	202,853	(179,151)	393,166
General and administrative	40,638	65,071	4,889	(1,226)	109,372
Depreciation, depletion, amortization and impairment	957,509	1,263,478	7,875	—	2,228,862
Gain on derivative contracts	(211,439)	—	—	—	(211,439)
Total expenses	859,181	1,625,540	215,617	(180,377)	2,519,961
(Loss) income from operations	(530,072)	(810,606)	2,531	—	(1,338,147)
Equity earnings from subsidiaries	(809,594)	809	—	808,785	—
Interest expense, net	(140,022)	(2,132)	(1,304)	—	(143,458)
Other income, net	36	2,534	282	—	2,852
(Loss) income before income taxes	(1,479,652)	(809,395)	1,509	808,785	(1,478,753)
Income tax (benefit) expense	(38,372)	44	—	—	(38,328)
Net (loss) income	(1,441,280)	(809,439)	1,509	808,785	(1,440,425)
Less: net income attributable to noncontrolling interest	—	155	700	—	855
Net (loss) income attributable to SandRidge Energy, Inc.	$(1,441,280)	$ (809,594)	$ 809	$ 808,785	$(1,441,280)

SandRidge Energy, Inc., and Subsidiaries
Notes to Consolidated Financial Statements—(continued)

Condensed Consolidating Statements of Cash Flows

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(In thousands)		
Year Ended December 31, 2010					
Net cash (used in) provided by operating activities	$ (442,955)	$ 823,534	$ 9,549	$—	$ 390,128
Net cash used in investing activities	(138,428)	(818,094)	(6,231)	—	(962,753)
Net cash provided by (used in) financing activities	582,485	(7,717)	(4,141)	—	570,627
Net increase (decrease) in cash and cash equivalents	1,102	(2,277)	(823)	—	(1,998)
Cash and cash equivalents at beginning of year	339	2,841	4,681	—	7,861
Cash and cash equivalents at end of year	$ 1,441	$ 564	$ 3,858	$—	$ 5,863
Year Ended December 31, 2009					
Net cash (used in) provided by operating activities	$ (717,969)	$1,008,040	$ 21,488	$—	$ 311,559
Net cash used in investing activities	(240,992)	(990,122)	(15,945)	—	(1,247,059)
Net cash provided by (used in) financing activities	959,282	(15,669)	(888)	—	942,725
Net increase in cash and cash equivalents	321	2,249	4,655	—	7,225
Cash and cash equivalents at beginning of year	18	592	26	—	636
Cash and cash equivalents at end of year	$ 339	$ 2,841	$ 4,681	$—	$ 7,861
Year Ended December 31, 2008					
Net cash (used in) provided by operating activities	$ (309,359)	$ 858,868	$ 29,680	$—	$ 579,189
Net cash used in investing activities	(1,042,633)	(849,280)	(17,530)	—	(1,909,443)
Net cash provided by (used in) financing activities	1,289,043	(9,044)	(12,244)	—	1,267,755
Net (decrease) increase in cash and cash equivalents	(62,949)	544	(94)	—	(62,499)
Cash and cash equivalents at beginning of year	62,967	48	120	—	63,135
Cash and cash equivalents at end of year	$ 18	$ 592	$ 26	$—	$ 636

27. Supplemental Information on Oil and Natural Gas Producing Activities

The Supplementary Information on Oil and Natural Gas Producing Activities is presented as required by ASC Topic 932, Extractive Activities — Oil and Gas. The supplemental information includes capitalized costs related to oil and natural gas producing activities; costs incurred in oil and natural gas property acquisition, exploration and development; and the results of operations for oil and natural gas producing activities. Supplemental information is also provided for oil and natural gas production and average sales prices; the estimated quantities of proved oil and natural gas reserves; the standardized measure of discounted future net cash flows associated with proved oil and natural gas reserves; and a summary of the changes in the standardized measure of discounted future net cash flows associated with proved oil and natural gas reserves.

Capitalized Costs Related to Oil and Natural Gas Producing Activities

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

	December 31,		
	2010	2009	2008
Oil and natural gas properties:			
Proved	$ 8,159,924	$ 5,913,408	$ 4,676,072
Unproved	547,953	281,811	215,698
Total oil and natural gas properties	8,707,877	6,195,219	4,891,770
Less accumulated depreciation, depletion and impairment	(4,483,736)	(4,223,437)	(2,369,840)
Net oil and natural gas properties capitalized costs	$ 4,224,141	$ 1,971,782	$ 2,521,930

Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development

Costs incurred in oil and natural gas property acquisition, exploration and development activities which have been capitalized are summarized as follows (in thousands):

	Year Ended December 31,		
	2010	2009	2008
Acquisitions of properties:			
Proved	$1,346,303	$ 749,070	$ 366,275
Unproved	352,648	67,731	16,982
Exploration(1)	31,717	126,345	391,672
Development(2)	1,006,232	407,409	1,132,078
Total cost incurred	$2,736,900	$1,350,555	$1,907,007

(1) Includes seismic costs of $4.1 million, $6.8 million and $68.8 million for 2010, 2009 and 2008, respectively, and pipe inventory costs of $77.7 million and $47.2 million for 2009 and 2008, respectively.

(2) Includes estimated loss currently identified on the construction of the Century Plant of $105.0 million for 2010. See Note 13.

Results of Operations for Oil and Natural Gas Producing Activities (Unaudited)

The Company's results of operations from oil and natural gas producing activities for each of the years 2008, 2009 and 2010 are shown in the following table (in thousands):

For the Year Ended December 31, 2008	
Revenues	$ 908,689
Expenses:	
Production costs	189,598
Depreciation, depletion and amortization expenses	2,140,685
Total expenses	2,330,283
Loss before income taxes	(1,421,594)
Benefit of income taxes	(36,819)
Results of operations for oil and natural gas producing activities (excluding corporate overhead and interest costs)	$(1,384,775)
For the Year Ended December 31, 2009	
Revenues	$ 454,705
Expenses:	
Production costs	173,295
Depreciation, depletion, amortization and impairment expenses	1,869,314
Total expenses	2,042,609
Loss before income taxes	(1,587,904)
Benefit of income taxes	(7,940)
Results of operations for oil and natural gas producing activities (excluding corporate overhead and interest costs)	$(1,579,964)
For the Year Ended December 31, 2010	
Revenues	$ 774,763
Expenses:	
Production costs	267,033
Depreciation, depletion and amortization expenses	275,335
Total expenses	542,368
Income before income taxes	232,395
Benefit of income taxes(1)	(405,413)
Results of operations for oil and natural gas producing activities (excluding corporate overhead and interest costs)	$ 637,808

(1) Reflects the Company's effective tax rate, including the partial valuation allowance release.

Oil and Natural Gas Reserve Quantities (Unaudited)

Proved oil and natural gas reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible, based on prices used to estimate reserves, from a given date forward from known reservoirs, and under existing economic conditions, operating methods, and government regulation before the time of which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. Proved developed reserves are proved reserves expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well. Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively large major expenditure is required for recompletion.

The table below represents the Company's estimate of proved oil and natural gas reserves attributable to the Company's net interest in oil and natural gas properties, all of which are located in the continental United States, based upon the evaluation by the Company and its independent petroleum engineers of pertinent geoscience and engineering data in accordance with the SEC's regulations. Estimates of substantially all of the Company's proved reserves have been prepared by 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 SEC.

Netherland Sewell, DeGolyer and MacNaughton and Lee Keeling, independent oil and natural gas consultants, prepared the estimates of proved reserves of oil and natural gas attributable to substantially all of the Company's net interest in oil and natural gas properties as of the end of one or more of 2010, 2009 and 2008. Netherland Sewell, DeGolyer and MacNaughton and Lee Keeling are independent petroleum engineers, geologists, geophysicists and petrophysicists and do not own an interest in the Company or its properties and are not employed on a contingent basis. Netherland Sewell and Lee Keeling prepared the estimates of proved reserves for a majority of the Company's properties other than those held by SandRidge Tertiary, LLC (formerly PetroSource Production Co), which constitute approximately 92.2% of the Company's total proved reserves as of December 31, 2010. DeGolyer and MacNaughton prepared the estimates of proved reserves for SandRidge Tertiary, LLC, which constitute approximately 4.3% of our total proved reserves as of December 31, 2010. The remaining 3.5% of estimates of proved reserves were based on Company estimates.

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

During 2008, the Company recognized additional reserves attributable to extensions and discoveries as a result of successful drilling in the Piñon Field. Drilling expenditures of $129.8 million resulted in the addition of 9.6 MMBoe or 57.8 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 22.8 MMBoe or 136.5 Bcfe of net proved reserve extensions in the Piñon Field for 2008 are proved undeveloped reserves associated with direct offsets to the drilling program extending the boundaries of the Piñon Field and zone identification. Changes in reserves associated with development drilling have been accounted for in revisions of previous reserve estimates.

During 2009, the Company recognized downward revisions of 1,123.8 Bcf in its natural gas reserve quantities as lower natural gas prices used in the estimation of reserves as of December 31, 2009 compared to prices used in the estimation of reserves in the previous periods caused (1) a significant number of proved undeveloped reserve locations to generate no discounted future net cash flows resulting in the elimination of associated reserve quantities and (2) a shortening of the productive lives of certain proved properties that became uneconomic earlier in their lives with the use of lower natural gas prices. The natural gas price used in the estimation as of December 31, 2009, which is a 12-month average price in accordance with SEC rules, was $3.87 per Mcf compared to the index price at December 31, 2008 of $5.71 per Mcf used in the estimation of year end 2008 reserves. The remaining 121.1 Bcf of negative revisions were performance related.

During 2010, the Company recognized additional proved oil reserves of 154.2 MMBbls, which were primarily attributable to the acquisition of reserves in place from Arena and extensions and discoveries associated with successful drilling in the Permian Basin and Mid-Continent areas. The addition of 867.9 Bcf of natural gas reserves are primarily attributable to the increase in natural gas prices used in the estimation of reserves as of December 31, 2010 compared to prices used in the estimation of reserves in the previous periods, with other natural gas reserves being added in connection with the acquisition of reserves in place from Arena and extensions and discoveries associated with successful drilling in the Permian Basin and Mid-Continent areas.

The summary below presents changes in the Company's estimated reserves for 2008, 2009 and 2010.

	Oil (MBbls)	Natural Gas (MMcf)(1)
Proved developed and undeveloped reserves:		
As of December 31, 2007	36,527	1,297,029
Revisions of previous estimates	6,738	412,155
Acquisitions of new reserves	513	38,008
Extensions and discoveries	1,728	241,596
Sales of reserves in place	(8)	(1,750)
Production	(2,334)	(87,402)
As of December 31, 2008	43,164	1,899,636
Revisions of previous estimates	8,826	(1,244,873)
Acquisitions of new reserves	56,342	104,046
Extensions and discoveries	8	8,890
Sales of reserves in place	(97)	(163)
Production	(2,894)	(87,461)
As of December 31, 2009	105,349	680,075
Revisions of previous estimates	12,999	867,931
Acquisitions of new reserves	71,640	79,942
Extensions and discoveries	69,512	211,150
Sales of reserves in place	—	(207)
Production	(7,386)	(76,226)
As of December 31, 2010	252,114	1,762,665
Proved developed reserves(2):		
As of December 31, 2007	12,532	590,358
As of December 31, 2008	15,342	851,357
As of December 31, 2009	38,327	592,777
As of December 31, 2010	91,965	784,292
Proved undeveloped reserves(2):		
As of December 31, 2007	23,995	706,671
As of December 31, 2008	27,822	1,048,279
As of December 31, 2009	67,022	87,298
As of December 31, 2010	160,149	978,373

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

(2) Our estimated proved reserves were determined using a 12-month average price for oil and natural gas for the years ended December 31, 2010 and 2009 and year-end prices for oil and natural gas as of December 31, 2008 and 2007.

Standardized Measure of Discounted Future Net Cash Flows (Unaudited)

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 ASC Topic 932. 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 oil, natural gas and natural gas liquids reserves and projected future production volumes based upon economic conditions;
- pricing is applied based upon 12-month average market prices at December 31, 2010 and 2009 and year end prices for December 31, 2008 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,		
	2010	2009	2008
Oil (per barrel)	$66.93	$49.98	$39.42
Natural gas (per Mcf)	$ 3.80	$ 3.41	$ 4.94

- 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.

The summary below presents the Company's future net cash flows relating to proved oil and natural gas reserves based on the standardized measure in ASC Topic 932.

	(In thousands)
As of December 31, 2008	
Future cash inflows from production	$11,092,154
Future production costs	(3,887,553)
Future development costs(a)	(2,153,506)
Future income tax expenses	(399,014)
Undiscounted future net cash flows	4,652,081
10% annual discount	(2,431,505)
Standardized measure of discounted future net cash flows	$ 2,220,576
As of December 31, 2009	
Future cash inflows from production	$ 7,582,670
Future production costs	(3,028,888)
Future development costs(a)	(938,272)
Future income tax expenses	—
Undiscounted future net cash flows	3,615,510
10% annual discount	(2,054,532)
Standardized measure of discounted future net cash flows	$ 1,560,978
As of December 31, 2010	
Future cash inflows from production	$23,564,771
Future production costs	(8,218,860)
Future development costs(a)	(3,779,761)
Future income tax expenses	(2,392,464)
Undiscounted future net cash flows	9,173,686
10% annual discount	(5,490,171)
Standardized measure of discounted future net cash flows	$ 3,683,515

(a) Includes abandonment costs.

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 Associated with Proved Oil and Natural Gas Reserves

Present value as of December 31, 2007	$ 2,718,537
Changes during the year:	
Revenues less production and other costs	(719,091)
Net changes in prices, production and other costs	(1,747,962)
Development costs incurred	1,132,078
Net changes in future development costs	(1,152,018)
Extensions and discoveries	227,874
Revisions of previous quantity estimates	757,939
Accretion of discount	168,811
Net change in income taxes	794,001
Purchases of reserves in-place	47,767
Sales of reserves in-place	(2,076)
Timing differences and other(a)	(5,284)
Net change for the year	(497,961)
Present value as of December 31, 2008	2,220,576
Changes during the year:	
Revenues less production and other costs	(281,410)
Net changes in prices, production and other costs	(1,841,292)
Development costs incurred	201,467
Net changes in future development costs	1,075,246
Extensions and discoveries	8,671
Revisions of previous quantity estimates	(553,469)
Accretion of discount	109,512
Net change in income taxes	37,936
Purchases of reserves in-place	565,457
Sales of reserves in-place	(131)
Timing differences and other(a)	18,415
Net change for the year	(659,598)
Present value as of December 31, 2009	1,560,978
Changes during the year:	
Revenues less production and other costs	(507,730)
Net changes in prices, production and other costs	967,967
Development costs incurred	366,539
Net changes in future development costs	(910,934)
Extensions and discoveries	955,540
Revisions of previous quantity estimates	773,132
Accretion of discount	159,971
Net change in income taxes	(825,668)
Purchases of reserves in-place	1,133,413
Sales of reserves in-place	(258)
Timing differences and other(a)	10,565
Net change for the year	2,122,537
Present value as of December 31, 2010	$ 3,683,515

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

28. Quarterly Financial Results (Unaudited)

The Company's operating results for each quarter of 2010 and 2009 are summarized below (in thousands, except per share data).

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2010:				
Total revenues	$ 210,994	$182,439	$ 245,233	$ 293,070
Income (loss) from operations	$ 89,170	$119,452	$ (87,430)	$(127,978)
Net income (loss)(1)	$ 28,374	$ 54,611	$ 307,602	$(195,577)
Income (loss) applicable to SandRidge Energy, Inc., common stockholders(1)	$ 18,605	$ 44,884	$ 297,657	$(208,023)
Income (loss) per share applicable to SandRidge Energy, Inc., common stockholders(2):				
Basic	$ 0.09	$ 0.21	$ 0.82	$ (0.53)
Diluted	$ 0.09	$ 0.20	$ 0.73	$ (0.53)
2009:				
Total revenues	$ 159,013	$134,099	$ 134,855	$ 163,077
Loss from operations(3)	$(1,116,280)	$(49,987)	$ (50,229)	$(388,528)
Net loss (3)	$(1,154,854)	$(91,170)	$(101,312)	$(425,996)
Loss applicable to SandRidge Energy, Inc., common stockholders(2)	$(1,154,857)	$(91,174)	$(104,132)	$(434,240)
Loss per share applicable to SandRidge Energy, Inc., common stockholders(2):				
Basic	$ (7.07)	$ (0.52)	$ (0.58)	$ (2.36)
Diluted	$ (7.07)	$ (0.52)	$ (0.58)	$ (2.36)

(1) Includes a valuation allowance release of $456.4 million for the third quarter.

(2) Income (loss) per share 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) per share available (applicable) to common stockholders for each of the four quarters may not equal the fiscal year amount.

(3) Includes a full cost ceiling impairment of $1,304.4 million and $388.9 million for the first quarter of 2009 and fourth quarter of 2009, respectively.

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.

SANDRIDGE ENERGY, INC.

By /s/ Tom L. Ward

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

February 28, 2011

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Tom L. Ward, Philip T. Warman and Justin P. Byrne, and each of them severally, his true and lawful attorney or attorneys-in-fact and agents, with full power to act with or without the others and with full power of substitution and resubstitution, to execute in his name, place and stead, in any and all capacities, any or all amendments to this report, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents and each of them, full power and authority to do and perform in the name of on behalf of the undersigned, in any and all capacities, each and every act and thing necessary or desirable to be done in and about the premises, to all intents and purposes and as fully as they might or could do in person, hereby ratifying, approving and confirming all that said attorneys-in-fact and agents or their substitutes may lawfully do or cause to be done by virtue hereof.

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

Signature	Title	Date
/s/ TOM L. WARD **Tom L. Ward**	Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	February 28, 2011
/s/ JAMES D. BENNETT **James D. Bennett**	Chief Financial Officer and Executive Vice President (Principal Financial Officer)	February 28, 2011
/s/ RANDALL D. COOLEY **Randall D. Cooley**	Senior Vice President — Accounting (Principal Accounting Officer)	February 28, 2011
/s/ DANIEL W. JORDAN **Daniel W. Jordan**	Director	February 28, 2011
/s/ WILLIAM A. GILLILAND **William A. Gilliland**	Director	February 28, 2011
/s/ ROY T. OLIVER, JR. **Roy T. Oliver, Jr.**	Director	February 28, 2011
/s/ EVERETT R. DOBSON **Everett R. Dobson**	Director	February 28, 2011
/s/ D. DWIGHT SCOTT **D. Dwight Scott**	Director	February 28, 2011
/s/ JEFFERY S. SEROTA **Jeffery S. Serota**	Director	February 28, 2011

INVESTOR INFORMATION

CORPORATE HEADQUARTERS

SandRidge Energy, Inc.

123 Robert S. Kerr Avenue

Oklahoma City, Oklahoma 73102-6406

(405) 429-5500

ANNUAL MEETING

Corporate Headquarters

June 3, 2011, at 9:00 a.m.

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

PricewaterhouseCoopers LLP

1201 Louisiana, Suite 2900

Houston, Texas 77002

(713) 356-4000

TRANSFER AGENT & REGISTRAR

American Stock Transfer & Trust Company, LLC

Postal Address:

59 Maiden Lane

New York, New York 10038

Overnight Address:

Operations Center

6201 15th Avenue

Brooklyn, New York 11219

Shareholder Services:

(800) 937-5449 or (718) 921-8124

www.amstock.com/new/default.asp

INVESTOR RELATIONS CONTACT

Kevin R. White

Senior Vice President - Business Development

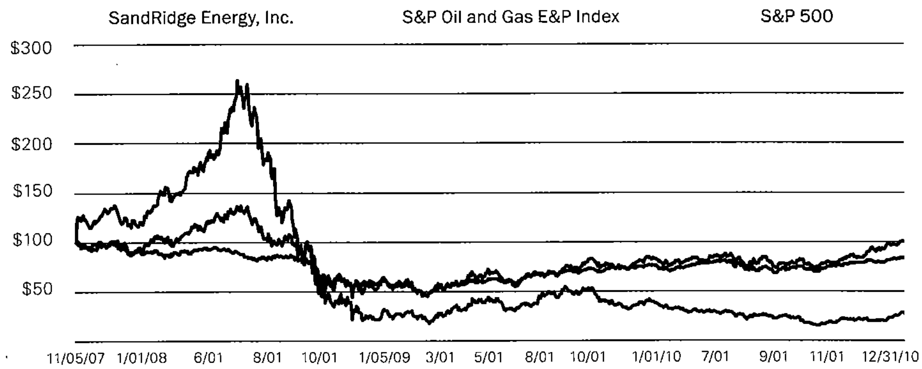
(405) 429-5515

investors@sandridgeenergy.com

PUBLICATIONS

A copy of SandRidge's annual report to the Securities and Exchange Commission (Form 10-K) and other publications are available upon request at no charge. For copies of this or any other SandRidge publication, please contact our Investor Relations department.

SANDRIDGE COMMON STOCK PRICE PERFORMANCE COMPARISON



The above graph compares the cumulative total return to shareholders on SandRidge Energy, Inc.'s (SD) common stock relative to the cumulative total returns of the S&P 500 Index and the S&P Oil and Gas Exploration and Production Index from November 5, 2007 (the date of SD's initial public offering) through December 31, 2010. The graph assumes that the value of the investment in the company's common stock and in each of the indexes was $100.00 on November 5, 2007.

STOCK PRICE

Our common stock is listed on the New York Stock Exchange ("NYSE") under the symbol "SD." The range of high and low sales prices for our common stock for the periods indicated, as reported by the NYSE, is as follows:

2010	High	Low
First	$11.08	$7.13
Second	$8.03	$5.21
Third	$6.79	$3.87
Fourth	$7.49	$4.85

2009	High	Low
First	$8.79	$4.49
Second	$11.84	$6.31
Third	$15.00	$7.44
Fourth	$14.08	$7.97

FORWARD-LOOKING STATEMENTS

This annual report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. These statements express a belief, expectation or intention and are generally accompanied by words that convey projected future events or outcomes. The forward-looking statements include statements about SandRidge Energy, Inc.'s future operations, rig and well counts, drilling and resource locations, anticipated exploration and production strategies, including our increased focus on oil production, estimates of oil and natural gas production, reserve volumes and reserve values, projected expenses, revenue, earnings, cash flow, capital expenditures and other costs, capital raising activities, including potential asset divestitures, and hedge transactions. We have based these forward-looking statements on our current expectations and assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments, as well as other factors we believe are appropriate under the circumstances. However, whether actual results and developments will conform with our expectations and predictions is subject to a number of risks and uncertainties, including the volatility of oil and natural gas prices, our success in discovering, estimating, and developing oil and natural gas reserves, the availability and terms of capital, our timely execution of hedge transactions, credit conditions of global capital markets, changes in economic conditions, regulatory changes, including those related to carbon dioxide and greenhouse gas emissions, and other factors, many of which are beyond our control. We refer you to the discussion of risk factors in Part I, Item 1A - "Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2010 and in comparable "risk factors" sections of our Quarterly Reports on Form 10-Q filed after the date of this annual report. All of the forward-looking statements made in this annual report are qualified by these cautionary statements. The actual results or developments anticipated may not be realized or, even if substantially realized, they may not have the expected consequences to or effects on our company or our business or operations. Such statements are not guarantees of future performance and actual results or developments may differ materially from those projected in the forward-looking statements. We undertake no obligation to update or revise any forward-looking statements.

The SEC permits oil and natural gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserves, as each is defined by the SEC. At times we use the term "EUR" (estimated ultimate recovery) and "resources" and "resource locations and potential" to provide estimates that the SEC's guidelines prohibit us from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved, probable or possible reserves and, accordingly, are subject to substantially greater risk of being actually realized by the company. For a discussion of the company's proved reserves, as calculated under current SEC rules, we refer you to the company's Annual Report on Form 10-K accompanying this report.

SandRidge Energy, Inc.

123 Robert S. Kerr Avenue
Oklahoma City, Oklahoma 73102-6406

www.SandRidgeEnergy.com