SandRidge Holdings, Inc.
Form S-4
June 24, 2008

Table of Contents

As filed with the Securities and Exchange Commission on June 24, 2008

Registration No. 333-

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form S-4
REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933
SandRidge Energy, Inc.*
(Exact name of registrant as specified in its charter)

Delaware	**1311**	**20-8084793**
(State or other jurisdiction of incorporation or organization)	*(Primary Standard Industrial Classification Code Number)*	*(I.R.S. Employer Identification Number)*

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

Copy to:

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

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

If the securities being registered on this Form are being offered in connection with the formation of a holding company and there is compliance with General Instruction G, check the following box. o

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

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

offering. o

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

* Includes certain subsidiaries of SandRidge Energy, Inc. identified below.

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities to be Registered	Amount to be Registered	Proposed Maximum Offering Price per Note(1)	Proposed Maximum Aggregate Offering Price(1)	Amount of Registration Fee
Senior Notes Due 2015	$650,000,000	100%	$650,000,000	$25,545
Guarantees of Senior Notes Due 2015(2)				
Senior Floating Rate Notes Due 2014	$350,000,000	100%	$350,000,000	$13,755
Guarantees of Senior Floating Rate Notes Due 2014(2)				
Total			$1,000,000,000	$39,300

(1) Estimated solely for the purpose of calculating the registration fee pursuant to Rule 457(f)(2) of the rules and regulations under the Securities Act.
(2) No further fee is payable pursuant to Rule 457(n) of the rules and regulations under the Securities Act, and no separate consideration will be received for the guarantees.

ADDITIONAL GUARANTOR REGISTRANTS

Exact Name of Additional Registrant as Specified in its Charter	State of Incorporation or Organization	Primary Standard Industrial Classification Code Number	IRS Employee Identification No.
SandRidge Onshore, LLC	Delaware	1311	47-0953489
Lariat Services, Inc.	Texas	1311	75-2500702
SandRidge Operating Company	Texas	1311	75-2541245
Integra Energy, LLC	Texas	1311	75-2887527
SandRidge Exploration and Production, LLC	Delaware	1311	87-0776535
SandRidge Tertiary, LLC	Texas	1311	20-1918006
SandRidge Midstream, Inc.	Texas	1311	75-2541148

SandRidge Offshore, LLC	Delaware	1311	11-3758786
SandRidge Holdings, Inc.	Delaware	1311	20-5878401

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

Table of Contents

PROSPECTUS

SandRidge Energy, Inc.

Offers to Exchange up to
$650,000,000 of 85/8% Senior Notes Due 2015
that have been registered under the Securities Act of 1933
for
$650,000,000 of 85/8% Senior Notes Due 2015
that have not been registered under the Securities Act of 1933
and
$350,000,000 of Senior Floating Rate Notes Due 2014
that have been registered under the Securities Act of 1933
for
$350,000,000 of Senior Floating Rate Notes Due 2014
that have not been registered under the Securities Act of 1933

Terms of the Exchange Offers

We are offering to exchange up to:

$650,000,000 aggregate principal amount of registered 85/8% Senior Notes Due 2015, for any and all of our $650,000,000 aggregate principal amount of unregistered 85/8% Senior Notes Due 2015; and

$350,000,000 aggregate principal amount of registered Senior Floating Rate Notes Due 2014, for any and all of our $350,000,000 aggregate principal amount of unregistered Senior Floating Rate Notes Due 2014.

We refer to the registered notes collectively as the exchange notes and the unregistered notes collectively as the outstanding notes . We refer to the exchange notes and the outstanding notes collectively as the notes . The exchange notes are being issued under the indenture pursuant to which we previously issued the outstanding notes.

We will exchange all outstanding notes that you validly tender and do not validly withdraw before the applicable exchange offer expires for an equal principal amount of exchange notes of the same series.

The terms of the exchange notes of each series are substantially identical to those of the outstanding notes of the same series, except that the transfer restrictions, registration rights and provisions for additional interest relating to the outstanding notes do not apply to the exchange notes.

The outstanding notes are, and the exchange notes will be, guaranteed by each of our existing and future domestic restricted subsidiaries.

Each exchange offer expires at 5:00 p.m., New York City time, on , 2008, unless extended. We do not currently intend to extend the exchange offers.

Tenders of outstanding notes may be withdrawn at any time prior to the expiration of the applicable exchange offer.

The exchange of outstanding notes for exchange notes will not be a taxable event for U.S. federal income tax purposes.

This investment involves risks. Please read Risk Factors beginning on page 5 for a discussion of the risks that you should consider prior to tendering your outstanding notes in the exchange offers.

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

The date of this prospectus is , 2008.

This prospectus incorporates important business and financial information about us that is not included in or delivered with this document. This information is available to you without charge upon written or oral request to: SandRidge Energy, Inc., 1601 N.W. Expressway, Suite 1600, Oklahoma City, Oklahoma 73118, Attention: Corporate Secretary, (405) 753-5500. The exchange offer is expected to expire on , 2008 and you must make your exchange decision by the expiration date. To obtain timely delivery, you must request the information no later than , 2008, or the date which is five business days before the expiration date of this exchange offer.

This prospectus is part of a registration statement we filed with the Securities and Exchange Commission, referred to in this prospectus as the SEC or the Commission. In making your investment decision, you should rely only on the information contained in this prospectus and in the accompanying letter of transmittal. We have not authorized anyone to provide you with any other information. If you received any unauthorized information, you must not rely on it. We are not making an offer to sell these securities in any state or jurisdiction where the offer is not permitted. You should not assume that the information contained in this prospectus is accurate as of any date other than the date on the front cover of this prospectus.

Each broker-dealer that receives exchange notes for its own account pursuant to an exchange offer must acknowledge that it will deliver a prospectus in connection with any resale of such exchange notes. The letter of transmittal states that by so acknowledging and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an underwriter within the meaning of the Securities Act. This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of exchange notes received in exchange for outstanding notes where such outstanding notes were acquired by such broker-dealer as a result of market-making activities or other trading activities. We have agreed that, for a period of 180 days after the consummation of an exchange offer, we will make this prospectus available to any broker-dealer for use in connection with any such resale. Please read Plan of Distribution.

TABLE OF CONTENTS

Prospectus Summary	1
Risk Factors	5
Use of Proceeds	17
Ratio of Earnings to Fixed Charges	18
The Exchange Offers	19
Cautionary Statements Regarding Forward-Looking Statements	25
Selected Historical Consolidated Financial Data	26
Management s Discussion and Analysis of Financial Condition and Results of Operations	28
Business	57
Description of the Notes	81
Certain United States Federal Tax Considerations	125
Plan of Distribution	125
Legal Matters	126
Experts	126
Where You Can Find More Information	127
Index to Financial Statements	F-1
Letter of Transmittal	A-1
Glossary of Natural Gas and Oil Terms	B-1
Opinion of Vinson & Elkins LLP	
Computation of Ratio of Earnings to Fixed Charges	

Consent of PricewaterhouseCoopers LLP
Consent of Grant Thornton LLP
Consent of DeGolyer and MacNaughton
Consent of Netherland, Sewell & Associates, Inc.
Consent of Harper & Associates, Inc.

Table of Contents

PROSPECTUS SUMMARY

We have provided definitions for some of the natural gas and oil industry terms used in this prospectus in the Glossary of Natural Gas and Oil Terms included in this prospectus. In this prospectus, when we use the terms SandRidge, the Company, we, our, or us, we mean SandRidge Energy, Inc. and its subsidiaries on a consolidate basis, unless otherwise indicated or the context requires otherwise. SandRidge Tertiary refers to our wholly-owned subsidiary, SandRidge Tertiary LLC, formerly PetroSource Production Company, LLC, and Lariat refers to our wholly-owned subsidiary, Lariat Services, Inc.

Our Company

We are an independent natural gas and oil company headquartered in Oklahoma City, Oklahoma with our principal focus on exploration and production activities. We also own and operate natural gas gathering, marketing and processing facilities, CO_2 treating and transportation facilities, and tertiary oil recovery operations. In addition, we own and operate drilling rigs and a related oil field services business. We focus our exploration and production activities in West Texas, the Cotton Valley Trend in East Texas, the Gulf Coast, the Mid-Continent and the Gulf of Mexico.

Our principal executive offices are located at 1601 N.W. Expressway, Suite 1600, Oklahoma City, Oklahoma 73118 and our telephone number is (405) 753-5500. Our website is *http://www.sandridgeenergy.com*.

The Exchange Offers

On May 1, 2008, we issued the outstanding notes in a private placement. In connection with this issuance, we entered into a registration rights agreement in which we agreed, among other things, to deliver this prospectus to you and to use our best efforts to complete the exchange offer. The following is a summary of the exchange offer.

Outstanding notes	Our 85/8% Senior Notes Due 2015 and our Senior Floating Rate Notes Due 2014, which were issued on May 1, 2008.
Exchange notes	Our 85/8% Senior Notes Due 2015 and Senior Floating Rate Notes Due 2014. The terms of each series of exchange notes are substantially identical to those terms of the same series of outstanding notes, except that the transfer restrictions, the registration rights and provisions for additional interest relating to the outstanding notes do not apply to the exchange notes.
The exchange offers	We are offering to exchange upon the terms set forth in this prospectus and the accompanying letter of transmittal: up to $650,000,000 aggregate principal amount of our 85/8% Senior Notes Due 2015 that have been registered under the Securities Act of 1933, as amended (the Securities Act), in exchange for an equal outstanding principal amount of our 85/8% Senior Notes Due 2015 that have not been registered under the Securities Act; and

up to $350,000,000 aggregate principal amount of our Senior Floating Rate Notes Due 2014 that have been registered under the Securities Act in exchange for an equal outstanding principal amount of our Senior Floating Rate Notes Due 2014 that have not been registered under the Securities Act;

to satisfy our obligations under the registration rights agreement that we entered into when we issued the outstanding notes in transactions exempt from registration under the Securities Act.

Table of Contents

Expiration date	Each exchange offer will expire at 5:00 p.m., New York City time, on , 2008, unless we decide to extend it.
Conditions to the exchange offers	The registration rights agreement does not require us to accept outstanding notes for exchange if the applicable exchange offer or the making of any exchange by a holder of the outstanding notes would violate any applicable law or interpretation of the staff of the SEC. A minimum aggregate principal amount of outstanding notes being tendered is not a condition to either exchange offer.
Procedures for tendering outstanding notes	All of the outstanding notes are held in book-entry form through the facilities of The Depository Trust Company, or DTC. To participate in either exchange offer, you must follow the automatic tender offer program, or ATOP, procedures established by DTC for tendering notes held in book-entry form. The ATOP procedures require that the exchange agent receive, prior to the expiration date of the applicable exchange offer, a computer-generated message known as an agent s message that is transmitted through ATOP and that DTC confirm that DTC has received instructions to exchange your notes and you agree to be bound by the terms of the letter of transmittal in Annex A hereto. For more details, please read The Exchange Offers Terms of the Exchange and The Exchange Offers Procedures for Tendering.
Guaranteed delivery procedures	None.
Withdrawal of tenders	You may withdraw your tender of outstanding notes at any time prior to the expiration date of the applicable exchange offer. To withdraw, you must submit a notice of withdrawal to the exchange agent using ATOP procedures before 5:00 p.m., New York City time, on the expiration date of the applicable exchange offer. Please read The Exchange Offers Withdrawal Rights.
Acceptance of Outstanding Notes and Delivery of Exchange Notes	If you fulfill all conditions required for proper acceptance of outstanding notes, we will accept any and all outstanding notes that you properly tender in the applicable exchange offer before 5:00 p.m., New York City time, on the expiration date of the applicable exchange offer. We will return any outstanding note that we do not accept for exchange to you without expense promptly after the expiration date. We will deliver the exchange notes promptly after the expiration date and acceptance of the outstanding notes for exchange. Please read The Exchange Offers Terms of the Exchange Offers.
U.S. federal income tax considerations	The exchange of exchange notes for outstanding notes in the exchange offer will not be a taxable event for U.S. federal income tax purposes. Please read the discussion under the caption Certain U.S. Federal Tax Considerations for more information regarding the tax consequences to you of the exchange offer.

Use of proceeds	The issuance of the exchange notes will not provide us with any new proceeds. We are making each exchange offer solely to satisfy our obligations under the registration rights agreement.

Fees and expenses	We will pay all of our expenses related to the exchange offers.
Exchange Agent	We have appointed Wells Fargo Bank, National Association as exchange agent for each exchange offer. You can find the address, telephone number and fax number of the exchange agent under the caption The Exchange Offers Exchange Agent.
Consequences of not exchanging your outstanding notes	If you do not exchange your outstanding notes in the applicable exchange offer, you will no longer be able to require us to register your outstanding notes under the Securities Act, except in the limited circumstances provided under the registration rights agreement. In addition, you will not be able to resell, offer to resell or otherwise transfer the outstanding notes unless we have registered the outstanding notes under the Securities Act, or unless you resell, offer to resell or otherwise transfer them under an exemption from the registration requirements of, or in a transaction not subject to, the Securities Act. For information regarding the consequences of not tendering your outstanding notes and our obligation to file a registration statement, please read The Exchange Offers Consequences of Failure to Exchange Outstanding Securities and Description of the Notes.

Description of the Exchange Notes

The terms of the exchange notes and those of the outstanding notes are substantially identical, except that the transfer restrictions, registration rights and provisions for additional interest relating to the outstanding notes do not apply to the exchange notes. As a result, the exchange notes will not bear legends restricting their transfer and will not have the benefit of the registration rights and additional interest provisions contained in the outstanding notes. The exchange notes represent the same debt as the outstanding notes for which they are being exchanged. Both the outstanding notes and the exchange notes are governed by the same indenture.

The following is a summary of the terms of the exchange notes. It may not contain all the information that is important to you. For a more detailed description of the exchange notes, please read Description of the Notes.

Issuer	SandRidge Energy, Inc.
Securities offered	$650,000,000 aggregate principal amount of 85/8% Senior Notes Due 2015. $350,000,000 aggregate principal amount of Senior Floating Rate Notes Due 2014. The exchange notes are being offered as additional debt securities under the indenture pursuant to which we previously issued the outstanding notes.
Maturity date of the 85/8% Senior Notes	April 1, 2015

Maturity date of the Senior Floating Rate Notes	April 1, 2014
PIK interest	At our election, we may from time to time prior to April 30, 2011 upon notice elect to pay interest on the 85/8% Senior Notes in kind

Table of Contents

	by the issuance of additional principal amount of 85/8% Senior Notes.
Interest payment dates	Interest on the 85/8% Senior Notes is payable semi-annually on each April 1 and October 1 of each year beginning on October 1, 2008. Interest on the Senior Floating Rate Notes is payable quarterly in cash in arrears on each January 1, April 1, July 1 and October 1 of each year beginning on July 1, 2008. Interest on the exchange notes will accrue from April 1, 2008 in the case of the 85/8% Senior Notes and from July 1, 2008 in the case of the Senior Floating Rate Notes.
Guarantees	The exchange notes are unconditionally guaranteed by our existing restricted subsidiaries and will be guaranteed by our future domestic restricted subsidiaries.
Use of proceeds	The issuance of the exchange notes will not provide us with any new proceeds. We are making this exchange offer solely to satisfy our obligations under our registration rights agreement.
Ranking	The exchange notes of each series are unsecured and rank equally in right of payment with the exchange notes of the other series and with all of our other existing and future senior indebtedness. The exchange notes are senior in right of payment to all our future subordinated indebtedness.
Transfer restrictions	The exchange notes generally will be freely transferable, but will also be new securities for which there will not initially be a market. There can be no assurance as to the development or liquidity of any market for the exchange notes.

Risk Factors

Investing in the exchange notes involves substantial risk. Please read Risk Factors beginning on page 5 for a discussion of certain factors you should consider in evaluating an investment in the exchange notes.

RISK FACTORS

An investment in the exchange notes involves a significant degree of risk. You should consider carefully these risks together with all of the other information included in this prospectus before deciding whether to participate in the exchange offers. All of the risks described below could materially and adversely affect our business prospects, financial condition, operating results and cash flows, which in turn could adversely affect our ability to satisfy our obligations under the exchange notes and the guarantees of the exchange notes.

Risks Related to Our Business

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

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

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

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

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

As of March 31, 2008, our total indebtedness was $1.3 billion, which represented approximately 37% of our total capitalization and on May 20, 2008, we issued $750 million of our Senior Notes due 2018. Our substantial level of indebtedness increases the possibility that we may be unable to generate cash sufficient to pay, when due, the principal of, interest on or other amounts due in respect of our indebtedness. Our substantial indebtedness, combined with our lease and other financial obligations and contractual commitments, could have other important consequences to you. For example, it could:

- make us more vulnerable to adverse changes in general economic, industry and competitive conditions and adverse changes in governmental regulation;

Table of Contents

- require us to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness, thereby reducing the availability of our cash flows to fund working capital, capital expenditures, acquisitions and other general corporate purposes;

- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;

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

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

Any of these above listed factors could materially adversely affect 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.

The process of estimating natural gas and oil reserves is complex and inherently imprecise. It requires interpretations of available technical data and many assumptions, including assumptions relating to production rates and economic factors such as natural gas and oil prices, taxes, drilling and operating expenses, capital expenditures and availability of funds. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this prospectus. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond our control.

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

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

- actual prices we receive for natural gas and oil;

- actual cost of development and production expenditures;

- the amount and timing of actual production;

- supply of and demand for natural gas and oil; and

- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of natural gas and oil properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash

flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

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

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

Table of Contents

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

As of March 31, 2008, only 857 of our 5,020 identified potential future well locations had proved undeveloped reserves. These potential drilling locations, including those without proved undeveloped reserves, represent a significant part of our growth strategy. Our ability to drill and develop these locations is subject to a number of uncertainties, including the availability of capital, seasonal conditions, regulatory approvals, natural gas and oil prices, costs and drilling results. Because of these uncertainties, we do not know if the numerous potential drilling locations we have will ever be drilled or if we will be able to produce natural gas or oil from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from our current expectations, which could adversely affect our business.

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

We describe some of our current prospects and drilling locations and our plans to explore those prospects and drilling locations in this prospectus. A prospect is a property on which we have identified what our geoscientists believe, based on available seismic and geological information, to be indications of natural gas or oil. Our prospects and drilling locations are in various stages of evaluation, ranging from a prospect that is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation.

The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. Even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from the well or abandonment of the well. During 2007, we participated in drilling a total of 316 gross wells, of which eight have been identified as dry holes. During the three months ended March 31, 2008, we drilled 111 wells, none of which were identified as dry holes. If we drill additional wells that we identify as dry holes in our current and future prospects, our drilling success rate may decline and materially harm our business. In sum, the cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive.

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

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

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

Approximately 57% of the estimated proved reserves that we own or have under lease in the WTO and of our total proved reserves as of March 31, 2008 are proved undeveloped reserves. Development of these reserves may take

longer and require higher levels of capital expenditures than we currently anticipate. Therefore, ultimate recoveries from these fields may not match current expectations. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves.

Table of Contents

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

As of March 31, 2008, approximately 60% of our proved reserves and approximately 51% of our daily production were located in the West Texas Overthrust, or WTO. In addition, a substantial portion of our WTO natural gas contains a high concentration of CO_2 and requires treating. As a result, we may be disproportionately exposed to the impact of delays or interruptions of production from these wells caused by transportation and treatment capacity constraints, curtailment of production or treatment plant closures for scheduled maintenance or unanticipated occurrences.

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

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

Furthermore, when we treat the gas for the removal of CO_2, some of the methane is used to run the treatment plant as fuel gas and other methane and heavier hydrocarbons, such as ethane, propane and butane, cannot be separated from the CO_2 and is lost. This is known as plant shrink. Historically our plant shrink has been approximately 12% in the WTO. We do not know the amount of CO_2 we will encounter in any well until it is drilled. As a result, sometimes we encounter CO_2 levels in our wells that are higher than expected. The amount of CO_2 in the gas produced affects the heating content of the gas. For example, if a well is 65% CO_2, the gas produced often has a heating content of between 300 and 350 MBtu per Mcf. Giving consideration for plant shrink, as many as four Mcf of high CO_2 gas must be produced to sell one MmBtu of natural gas. We report our volumes of natural gas reserves and production net of CO_2 volumes that are removed prior to sales.

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

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

The profitability of our midstream business is materially impacted by the volume of natural gas we gather, transmit and process at our facilities. Most of the reserves backing up our midstream assets are operated by our exploration and production segment. A material decrease in natural gas production in our areas of operation would result in a decline in the volume of natural gas delivered to our pipelines and facilities for gathering, transmitting and processing. We have no control over many factors affecting production activity, including prevailing and projected energy prices, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulation and the availability and cost of capital. Failure to connect new wells to our gathering systems would result in the amount of natural gas we gather, transmit and process being reduced substantially over time and could, upon exhaustion of the current wells, cause us to abandon our gathering systems and, possibly cease gathering, transmission and processing operations. Our ability to connect to new wells will be dependent on the level of drilling activity in our areas of operations and competitive market factors. The effect of any material decrease in the volume of natural gas handled by our midstream assets would be to reduce our revenues, operating income and our ability to make payments on the

exchange notes.

Table of Contents

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

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

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

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

compliance with environmental and other regulatory requirements; and

adverse weather conditions.

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

Insurance against all operational risks is not available to us. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. We do not carry environmental insurance, for example. We could incur losses for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not

covered in full or in part by insurance could have a material adverse impact on our business activities, financial condition, results of operations and our ability to make payments on the exchange notes.

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

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

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

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

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

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

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

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

Our senior credit facility and the indentures governing the notes and our 8% Senior Notes Due 2018 restrict our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations. We also are required to comply with certain financial covenants and ratios. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control. Our failure to comply with any

of the restrictions and covenants under the senior credit facility or indentures could result in a default under those agreements, which could cause all of our indebtedness to be immediately due and payable.

Our revolving 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 redetermination of the borrowing base per calendar year. Unscheduled redeterminations may be made at our request, but are limited to two requests per year. The borrowing base is determined based on proved developed producing reserves, proved developed non-producing reserves and proved undeveloped reserves. Outstanding borrowings in excess of the borrowing base must be repaid immediately, or we must pledge other natural gas and oil properties as additional collateral. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under the revolving credit facility.

If the indebtedness under our revolving credit facility and indentures were to be accelerated, our assets may not be sufficient to repay such indebtedness in full. In particular, holders of the exchange notes will be paid only if we have assets remaining after we pay amounts due on our secured indebtedness, including our revolving credit facility. We have pledged a significant portion of our assets as collateral under our revolving credit facility. Please see Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

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

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

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

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

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

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

ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing natural gas and oil properties.

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

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

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

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

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

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

Under certain environmental laws that impose strict, joint and several liability, we may be required to remediate our contaminated properties regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were or were not in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons, property or natural resources may result from environmental and other impacts of our operations. Moreover, new or modified environmental, health or safety laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. Therefore, the costs to comply with environmental, health or safety laws or regulations or the liabilities incurred

in connection with them could significantly and adversely affect our business, financial condition or results of operations. In addition, many countries as well as several states and regions of the U.S. have agreed to regulate emissions of greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning of natural gas and oil, are

greenhouse gases. The carbon dioxide may be released or captured as part of our operations. Current or future regulation of greenhouse gases could adversely impact our financial condition and results of operations and demand for some of our services or products in the future.

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

We are not currently required to comply with Section 404 of the Sarbanes Oxley Act of 2002, and are therefore not required to make an assessment of the effectiveness of our internal controls over financial reporting for that purpose. Management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with generally accepted accounting principles. A material weakness is a deficiency, or a combination of deficiencies, in our internal control over financial reporting that results in a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis. Effective internal controls are necessary for us to provide reliable financial reports and effectively prevent fraud. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. Our efforts to develop and maintain our internal controls may not be successful, and we may be unable to maintain adequate controls over our financial processes and reporting in the future, including future compliance with the obligations under Section 404 of the Sarbanes-Oxley Act of 2002. We will be required to comply with Section 404 of the Sarbanes-Oxley Act of 2002 effective as of December 31, 2008. Any failure to develop or maintain effective controls, or difficulties encountered in their implementation or other effective improvement of our internal controls could harm our operating results. Ineffective internal controls could also cause investors to lose confidence in our reported financial information.

Risks Relating to the Notes and the Exchange Offers

If you fail to exchange outstanding notes, existing transfer restrictions will remain in effect and the market value of outstanding notes may be adversely affected because they may be more difficult to sell.

If you fail to exchange outstanding notes for exchange notes under the exchange offers, then you will continue to be subject to the existing transfer restrictions on the outstanding notes. In general, the outstanding notes may not be offered or sold unless they are registered or exempt from registration under the Securities Act and applicable state securities laws. Except in connection with these exchange offers or as required by the registration rights agreement, we do not intend to register resales of the outstanding notes.

The tender of outstanding notes under the exchange offers will reduce the principal amount of the currently outstanding notes. Due to the corresponding reduction in liquidity, this may have an adverse effect upon, and increase the volatility of, the market price of any currently outstanding notes that you continue to hold following completion of the exchange offers.

We may incur substantial additional indebtedness, including debt ranking equal to the notes.

Subject to the restrictions in the indenture governing the exchange notes and outstanding notes and in other instruments governing our other outstanding debt, we and our subsidiaries may be able to incur substantial additional debt in the future. Although the indenture governing the exchange notes and outstanding notes and the instruments governing certain of our other outstanding debt contain restrictions on the incurrence of additional debt, these restrictions are subject to a number of significant qualifications and exceptions, and debt incurred in compliance with these restrictions could be substantial. To the extent new debt is added to our current debt levels, the substantial leverage-related risks described above would increase.

If we or any of our subsidiaries that is a guarantor of the exchange notes and outstanding notes (a Guarantor) incur any additional debt that ranks equally with the notes (or with the guarantee thereof), including trade payables, the holders of that debt will be entitled to share ratably with holders of the notes in

any proceeds distributed in connection with any insolvency, liquidation, reorganization, dissolution or other winding-up of us or such Guarantor. This may have the effect of reducing the amount of proceeds paid to holders of the notes in connection with such a distribution.

We may not be able to generate sufficient cash to service all of our indebtedness, including the notes, and may be forced to take other actions to satisfy our obligations under our indebtedness, which may not be successful.

Our ability to make scheduled payments on or to refinance our debt obligations depends on our financial condition and operating performance, which is subject to prevailing economic and competitive conditions and to certain financial, business and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness, including the notes.

If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to reduce or delay investments and capital expenditures, or to sell assets, seek additional capital or restructure or refinance our indebtedness, including the notes. Our ability to restructure or refinance our debt will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of our debt could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. The terms of existing or future debt instruments and the indenture governing the notes may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on our outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness. In the absence of such operating results and resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet our debt service and other obligations. Our senior credit facility and the indentures governing the notes and our other series of outstanding notes restrict our ability to dispose of assets and use the proceeds from the disposition. We may not be able to consummate those dispositions or to obtain the proceeds that we could realize from them and these proceeds may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations.

Your right to receive payments on the exchange notes, like the outstanding notes, is effectively junior to the right of lenders who have a security interest in our assets to the extent of the value of those assets.

Our obligations under the exchange notes, like the outstanding notes, and the Guarantors obligations under their guarantees of the exchange notes, like the outstanding notes, are unsecured, but our obligations under our senior credit facility and each Guarantor s obligations under its guarantee of our senior credit facility are secured by a security interest in substantially all of our domestic tangible and intangible assets, including the stock of substantially all of our wholly-owned subsidiaries. If we are declared bankrupt or insolvent, or if we default under our senior credit facility, the funds borrowed thereunder, together with accrued interest, could become immediately due and payable. If we were unable to repay such indebtedness, the lenders under our senior credit facility could foreclose on the pledged assets to the exclusion of holders of the notes, even if an event of default exists under the indenture governing the notes at such time. Furthermore, if the lenders foreclose and sell the pledged equity interests in any Guarantor in a transaction permitted under the terms of the indenture governing the notes, then such Guarantor will be released from its guarantee of the notes automatically and immediately upon such sale. In any such event, because the notes will no longer be secured by any of such assets or by the equity interests in any such Guarantor, it is possible that there would be no assets remaining from which your claims could be satisfied or, if any assets remained, they might be insufficient to satisfy your claims in full. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

As of June 20, 2008, we had no borrowings outstanding under our senior credit facility, though, at that time, outstanding letters of credit reduced borrowing capacity under the senior credit facility by $22 million. As of June 20, 2008, we had approximately $60.2 million of other outstanding secured long-term debt. Subject to the limits set forth in the indentures governing the notes and our 8% Senior Notes Due 2018, we may also incur additional secured debt.

Our ability to repay our debt, including the notes, is affected by the cash flow generated by our subsidiaries.

Our subsidiaries own some of our assets and conduct some of our operations. Accordingly, repayment of our indebtedness, including the notes, will be dependent on the generation of cash flow by our subsidiaries and their ability to make such cash available to us, by dividend, debt repayment or otherwise. Unless they are Guarantors, our subsidiaries will not have any obligation to pay amounts due on the notes or to make funds available for that purpose. Our subsidiaries may not be able to, or may not be permitted to, make distributions to enable us to make payments in respect of our indebtedness, including the notes. Each subsidiary is a distinct legal entity and, under certain circumstances, legal and contractual restrictions may limit our ability to obtain cash from our subsidiaries. While the indenture governing the notes limits the ability of our subsidiaries to incur consensual encumbrances or restrictions on their ability to pay dividends or make other intercompany payments to us, these limitations are subject to certain qualifications and exceptions. In the event that we do not receive distributions from our subsidiaries, we may be unable to make required principal and interest payments on our indebtedness, including the notes.

Claims of holders of the exchange notes, like holders of outstanding notes, will be structurally subordinated to claims of creditors of certain of our subsidiaries that will not guarantee the exchange notes.

We conduct some of our operations through our subsidiaries, and certain of our immaterial domestic subsidiaries have not guaranteed the notes. Subject to certain limitations, the indenture governing the notes permits us to form or acquire additional subsidiaries that are not guarantors of the notes and to permit such non-guarantor subsidiaries to acquire additional assets and incur additional indebtedness. Holders of the exchange notes would not have any claim as a creditor against any of our non-guarantor subsidiaries to the assets and earnings of those subsidiaries. The claims of the creditors of those subsidiaries, including their trade creditors, banks and other lenders, would have priority over any of our claims or those of our other subsidiaries as equity holders of the non-guarantor subsidiaries. Consequently, in any insolvency, liquidation, reorganization, dissolution or other winding-up of any of the non-guarantor subsidiaries, creditors of those subsidiaries would be paid before any amounts would be distributed to us or to any of the Guarantors as equity, and thus be available to satisfy our obligations under the notes and other claims against us or the Guarantors.

For the quarter ended March 31, 2008, our non-guarantor subsidiaries accounted for approximately $5.2 million, or 1.9%, of our revenues. As of March 31, 2008, our non-guarantor subsidiaries accounted for approximately $51.2 million, or 1.3%, of our consolidated total assets and $11.8 million, or 0.7%, of our total liabilities, in each case after giving effect to intercompany eliminations. The indenture governing the notes permits these subsidiaries to incur certain additional debt and will not limit their ability to incur other liabilities that are not considered indebtedness under the indenture.

If we default on our obligations to pay our other indebtedness, we may not be able to make payments on the notes.

Any default under the agreements governing our indebtedness, including a default under our senior credit facility, that is not waived by the required lenders, and the remedies sought by the holders of such indebtedness, could prevent us from paying principal, premium, if any, and interest on the notes and substantially decrease the market value of the notes. If we are unable to generate sufficient cash flow and are otherwise unable to obtain funds necessary to meet required payments of principal, premium, if any, and interest on our indebtedness, or if we otherwise fail to comply with the various covenants, including financial and operating covenants in the instruments governing our indebtedness (including covenants in our senior credit facility and the indentures governing the notes and our 8% Senior Notes Due 2018), we could be in default under the terms of the agreements governing such indebtedness. In the event of such default,

the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest;

- the lenders under our senior credit facility could elect to terminate their commitments thereunder, cease making further loans and institute foreclosure proceedings against our assets; and

- we could be forced into bankruptcy or liquidation.

If our operating performance declines, we may in the future need to obtain waivers from the required lenders under our senior credit facility to avoid being in default. If we breach our covenants under our senior credit facility and seek a waiver, we may not be able to obtain a waiver from the required lenders. If this occurs, we would be in default under our senior credit facility, the lenders could exercise their rights, as described above, and we could be forced into bankruptcy or liquidation.

We may not be able to repurchase the notes upon a change of control.

Upon the occurrence of specific kinds of change of control events, we may be required to offer to repurchase all notes then outstanding at 101% of their principal amount plus accrued and unpaid interest, if any. The source of funds for any such purchase of the notes will be our available cash or cash generated from our operations or the operations of our subsidiaries or other sources, including borrowings, sales of assets or sales of equity. We may not be able to repurchase the notes upon a change of control because we may not have sufficient financial resources to purchase all of the exchange notes that are tendered upon a change of control. Our failure to repurchase the exchange notes upon a change of control would cause a default under the indenture governing the notes and could lead to a cross default under the indenture for our 8% Senior Notes Due 2018 or our senior credit facility.

Insolvency and fraudulent transfer laws and other limitations may preclude the recovery of payment under the notes and the guarantees.

Federal and state fraudulent transfer laws permit a court, if it makes certain findings, to avoid all or a portion of the obligations of the Guarantors pursuant to their guarantees of the notes, or to subordinate a Guarantor s obligations under such guarantee to claims of its other creditors, reducing or eliminating the holders of the notes ability to recover under such guarantees. Although laws differ among these jurisdictions, in general, under applicable fraudulent transfer or conveyance laws, the notes or guarantees could be voided as a fraudulent transfer or conveyance if (1) we or any of the Guarantors, as applicable, issued the notes or incurred the guarantees with the intent of hindering, delaying or defrauding creditors; or (2) we or any of the Guarantors, as applicable, received less than reasonably equivalent value or fair consideration in return for either issuing the notes or incurring the guarantees and, in the case of (2) only, one of the following is also true:

- we or any of the Guarantors, as applicable, were insolvent or rendered insolvent by reason of the issuance of the notes or the incurrence of the guarantees or subsequently become insolvent for other reasons;

- the issuance of the notes or the incurrence of the guarantees left us or any of the Guarantors, as applicable, with an unreasonably small amount of capital to carry on the business;

- we or any of the Guarantors intended to, or believed that we or such Guarantor would, incur debts beyond our or such Guarantor s ability to pay such debts as they mature; or

- we or any of the Guarantors was a defendant in an action for money damages, or had a judgment for money damages docketed against us or such Guarantor if, in either case, after final judgment, the judgment is unsatisfied.

16

Table of Contents

USE OF PROCEEDS

The exchange offers are intended to satisfy our obligations under the registration rights agreement we entered into in connection with the issuance of the outstanding notes. We will not receive any cash proceeds from the issuance of the exchange notes in the exchange offers. In consideration for issuing the exchange notes as contemplated in this prospectus, we will receive in exchange outstanding notes in like principal amount. We will cancel all outstanding notes surrendered in exchange for exchange notes in the exchange offers. As a result, the issuance of the exchange notes will not result in any increase or decrease in our indebtedness.

Table of Contents

RATIO OF EARNINGS TO FIXED CHARGES

We have computed our ratio of earnings to fixed charges for the three months ended March 31, 2008 and 2007 and for each of our fiscal years ended December 31, 2003, 2004, 2005, 2006 and 2007. The computation of earnings to fixed charges is set forth on Exhibit 12.1 to the registration statement of which this prospectus forms a part.

Ratio of earnings to fixed charges is calculated by dividing earnings by fixed charges from operations for the periods indicated. For purposes of calculating the ratio of earnings to fixed charges, (a) earnings represents pre-tax income from continuing operations plus fixed charges and (b) fixed charges represents interest expensed and capitalized, amortization of financing costs and required dividends on preference securities.

You should read the ratio information below in conjunction with the Management s Discussion and Analysis of Financial Condition and Results of Operations and the financial statements and the notes thereto included elsewhere in this prospectus.

	For the Years Ended December 31,					For the Three Months Ended March 31,	
	2003	2004	2005	2006	2007	2007	2008
Ratio of earnings to fixed charges	19.4	12.2	6.3	2.2	1.7	(a)	(b)

(a) Due to our loss for the three months ended March 31, 2007, the ratio coverage was less than 1:1. We would have needed earnings of $29,994,000 to achieve coverage of 1:1.

(b) Due to our loss for the three months ended March 31, 2008, the ratio coverage was less than 1:1. We would have needed additional earnings of $87,163,000 to achieve coverage of 1:1.

Table of Contents

THE EXCHANGE OFFERS

Purpose and Effect of the Exchange Offers

We issued the outstanding notes, which consist of $650,000,000 in aggregate principal amount of 85/8% Senior Notes Due 2015 and $350,000,000 in aggregate principal amount of Senior Floating Rate Notes Due 2014, in a private placement on May 1, 2008. The outstanding notes were issued to qualified institutional buyers pursuant to Section 4(2) of the Securities Act in exchange for debt outstanding under our senior unsecured credit agreement. Accordingly, the outstanding notes are subject to transfer restrictions. In general, you may not offer or sell the outstanding notes unless either the offer and sale thereof are registered under the Securities Act or are exempt from or not subject to registration under the Securities Act and applicable state securities laws.

In the registration rights agreement, we agreed to use our best efforts to cause an exchange offer registration statement to be declared effective by November 1, 2008. Now, to satisfy our obligations under the registration rights agreement, we are offering holders of the outstanding notes who are able to make certain representations described below the opportunity to exchange their outstanding notes for the exchange notes in the exchange offers. The exchange offers will be open for a period of at least 20 business days. During the exchange offer period, we will issue the exchange notes in exchange for all outstanding notes properly surrendered and not withdrawn before the expiration date. The exchange notes will be registered and the transfer restrictions, registration rights and provisions for additional interest relating to the outstanding notes will not apply to the exchange notes.

Terms of the Exchange Offers

Subject to the terms and conditions described in this prospectus and in the applicable letter of transmittal, we will accept for exchange any outstanding notes properly tendered and not withdrawn prior to 5:00 p.m., New York City time, on the expiration date of the applicable exchange offer. We will issue exchange notes in principal amount equal to the principal amount of outstanding notes surrendered in the exchange offers. Outstanding notes may be tendered only for exchange notes and only in denominations of $1,000 and integral multiples of $1,000 in excess of $1,000.

Neither exchange offer is conditioned upon any minimum aggregate principal amount of outstanding notes being tendered in such exchange offer. Each exchange offer will be conducted independently from the other exchange offer, and consummation of one exchange offer will not be conditioned upon consummation of the other.

As of the date of this prospectus, $650,000,000 in aggregate principal amount of 85/8% Senior Notes Due 2015 and $350,000,000 in aggregate principal amount of Senior Floating Rate Notes Due 2014 are outstanding. This prospectus is being sent to DTC, the sole registered holder of the outstanding notes, and to all persons whom we can identify as beneficial owners of the outstanding notes. There will be no fixed record date for determining registered holders of outstanding notes entitled to participate in the exchange offers.

We intend to conduct the exchange offers in accordance with the provisions of the registration rights agreement, the applicable requirements of the Securities Act and the Securities Exchange Act of 1934, as amended, or the Exchange Act, and the rules and regulations of the SEC. Outstanding notes not tendered for exchange in the exchange offers will remain outstanding and continue to accrue interest. These outstanding notes will be entitled to the rights and benefits such holders have under the indenture relating to the notes and the registration rights agreement.

We will be deemed to have accepted for exchange properly tendered outstanding notes when we have given oral or written notice of the acceptance to the exchange agent and complied with the applicable provisions of the registration

rights agreement. The exchange agent will act as agent for the tendering holders for the purposes of receiving the exchange notes from us.

If you tender outstanding notes in the exchange offers, you will not be required to pay brokerage commissions or fees or, except to the extent indicated by the instructions to the letter of transmittal, transfer

Table of Contents

taxes with respect to the exchange of outstanding notes. We will pay all charges and expenses, other than certain applicable taxes described below, in connection with the exchange offer. Please read Fees and Expenses for more details regarding fees and expenses incurred in connection with the exchange offers. We will return any outstanding notes that we do not accept for exchange for any reason without expense to their tendering holders promptly after the expiration or termination of the applicable exchange offer.

Expiration, Extension and Amendment

Each exchange offer will expire at 5:00 p.m., New York City time, on , 2008, unless, in our sole discretion, we extend it. We may extend one exchange offer without extending the other.

We expressly reserve the right, at any time or various times, to extend the period of time during which either exchange offer is open. We may delay acceptance of any outstanding notes by giving oral or written notice of such extension to their holders at any time until the exchange offer expires or terminates. During any such extensions, all outstanding notes previously tendered will remain subject to the exchange offer, and we may accept them for exchange.

To extend either exchange offer, we will notify the exchange agent orally or in writing of any extension. We will notify the registered holders of outstanding notes of the extension no later than 9:00 a.m. New York City time on the business day after the previously scheduled expiration date.

Procedures for Tendering

To participate in the exchange offers, you must properly tender your outstanding notes to the exchange agent as described below. We will only issue exchange notes in exchange for outstanding notes that you timely and properly tender. Therefore, you should allow sufficient time to ensure timely delivery of your outstanding notes, and you should follow carefully the instructions on how to tender your outstanding notes. It is your responsibility to properly tender your outstanding notes. We have the right to waive any defects. We are not, however, required to waive defects, and neither we nor the exchange agent is required to notify you of any defects in your tender.

If you have any questions or need help in exchanging your outstanding notes, please call the exchange agent whose address and phone number are described in the letter of transmittal included as Annex A to this prospectus.

All of the outstanding notes were issued in book-entry form, and all of the outstanding notes are currently represented by global certificates registered in the name of Cede & Co., the nominee of DTC. We have confirmed with DTC that the outstanding notes may be tendered using ATOP. The exchange agent will establish an account with DTC for purposes of each exchange offer promptly after the commencement of such exchange offer, and DTC participants may electronically transmit their acceptance of the exchange offer by causing DTC to transfer their outstanding notes to the exchange agent using the ATOP procedures. In connection with the transfer, DTC will send an agent s message to the exchange agent. The agent s message will state that DTC has received instructions from the participant to tender outstanding notes and that the participant agrees to be bound by the terms of the letter of transmittal.

By using the ATOP procedures to exchange outstanding notes, you will not be required to deliver a letter of transmittal to the exchange agent. You will, however, be bound by its terms just as if you had signed it.

There is no procedure for guaranteed late delivery of the outstanding notes.

Determinations Under the Exchange Offers

We will determine in our sole discretion all questions as to the validity, form, eligibility, time of receipt, acceptance of tendered outstanding notes and withdrawal of tendered outstanding notes. Our determination will be final and binding. We reserve the absolute right to reject any outstanding notes not properly tendered or any outstanding notes our acceptance of which would, in the opinion of our counsel, be unlawful. We also reserve the right to waive any defect, irregularities or conditions of tender as to particular outstanding notes.

Table of Contents

Our interpretation of the terms and conditions of the exchange offers, including the instructions in the letter of transmittal, will be final and binding on all parties. Unless waived, all defects or irregularities in connection with tenders of outstanding notes must be cured within such time as we shall determine. Although we intend to notify holders of defects or irregularities with respect to tenders of outstanding notes, neither we, the exchange agent nor any other person will incur any liability for failure to give such notification. Tenders of outstanding notes will not be deemed made until such defects or irregularities have been cured or waived. Any outstanding notes received by the exchange agent that are not properly tendered and as to which the defects or irregularities have not been cured or waived will be returned to the tendering holder as soon as practicable following the expiration date of the applicable exchange offer.

When We Will Issue Exchange Notes

In all cases, we will issue exchange notes for outstanding notes that we have accepted for exchange under the applicable exchange offer only after the exchange agent receives, prior to 5:00 p.m., New York City time, on the expiration date of such exchange offer,

A book-entry confirmation of such outstanding notes into the exchange agent s account at DTC; and

A properly transmitted agent s message.

Return of Outstanding Notes Not Accepted or Exchanged

If we do not accept tendered outstanding notes for exchange or if outstanding notes are submitted for a greater principal amount than you desire to exchange, the unaccepted or non-exchanged outstanding notes will be returned without expense to their tendering holder. Such non-exchanged outstanding notes will be credited to an account maintained with DTC. These actions will occur as promptly as practicable after the expiration or termination of the applicable exchange offer.

Valid Tender

By agreeing to be bound by the letter of transmittal, you will represent to us that, among other things:

Any exchange notes that you receive will be acquired in the ordinary course of your business;

You have no arrangement or understanding with any person or entity to participate in the distribution of the exchange notes;

You are not engaged in and do not intend to engage in the distribution of the exchange notes;

If you are a broker-dealer who will receive exchange notes for your own account in exchange for outstanding notes, you acquired those outstanding notes as a result of market-making activities or other trading activities and you will deliver this prospectus, as required by law, in connection with any resale of the exchange notes; and

You are not an affiliate, as defined in Rule 405 under the Securities Act, of us.

Withdrawal Rights

Except as otherwise provided in this prospectus, you may withdraw your tender at any time prior to 5:00 p.m., New York City time, on the expiration date of the exchange offer. For a withdrawal to be effective you must comply with the appropriate ATOP procedures. Any notice of withdrawal must specify the name and number of the account at DTC to be credited with withdrawn outstanding notes and otherwise comply with the ATOP procedures.

We will determine all questions as to the validity, form, eligibility and time of receipt of a notice of withdrawal. Our determination shall be final and binding on all parties. We will deem any outstanding notes so withdrawn not to have been validly tendered for exchange for purposes of the exchange offers.

Table of Contents

Any outstanding notes that have been tendered for exchange but that are not exchanged for any reason will be credited to an account maintained with DTC for the outstanding notes. This return or crediting will take place as soon as practicable after withdrawal, rejection of tender, expiration or termination of the applicable exchange offer. You may retender properly withdrawn outstanding notes by following the procedures described under Procedures for Tendering above at any time on or prior to the expiration date of the applicable exchange offer.

Resales of Exchange Notes

Based on interpretations by the staff of the SEC, as described in no-action letters issued to third parties that are not related to us, we believe that exchange notes issued in the exchange offers in exchange for outstanding notes may be offered for resale, resold or otherwise transferred by holders of the exchange notes without compliance with the registration and prospectus delivery provisions of the Securities Act, if:

The exchange notes are acquired in the ordinary course of the holder s business;

The holders have no arrangement or understanding with any person to participate in the distribution of the exchange notes;

The holders are not affiliates of ours within the meaning of Rule 405 under the Securities Act; and

The holders are not broker-dealers who purchased outstanding notes directly from us for resale pursuant to Rule 144A or any other available exemption under the Securities Act.

However, the SEC has not considered the exchange offers described in this prospectus in the context of a no-action letter. The staff of the SEC may not make a similar determination with respect to the exchange offers as in the other circumstances. Each holder who wishes to exchange outstanding notes for exchange notes will be required to represent that it meets the above four requirements.

Any holder who is an affiliate of ours or who intends to participate in an exchange offer for the purpose of distributing exchange notes or any broker-dealer who purchased outstanding notes directly from us for resale pursuant to Rule 144A or any other available exemption under the Securities Act:

Cannot rely on the applicable interpretations of the staff of the SEC mentioned above;

Will not be permitted or entitled to tender its outstanding notes in the exchange offers; and

Must comply with the registration and prospectus delivery requirements of the Securities Act in connection with any secondary resale transaction.

Each broker-dealer that receives exchange notes for its own account in exchange for outstanding notes must acknowledge that the outstanding notes were acquired by it as a result of market-making activities or other trading activities and agree that it will deliver a prospectus that meets the requirements of the Securities Act in connection with any resale of the exchange notes. The letter of transmittal states that by so acknowledging and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an underwriter within the meaning of the Securities Act. Please read Plan of Distribution. A broker-dealer may use this prospectus, as it may be amended or supplemented from time to time, in connection with the resales of exchange notes received in exchange for outstanding notes that the broker-dealer acquired as a result of market-making or other trading activities. Any holder that is a broker-dealer participating in an exchange offer must notify the exchange agent at the telephone number set forth in the enclosed letter of transmittal and must comply with the procedures for broker-dealers participating in the exchange offer. We

have not entered into any arrangement or understanding with any person to distribute the exchange notes to be received in the exchange offers.

Table of Contents

Exchange Agent

Wells Fargo Bank, National Association has been appointed as the exchange agent for the exchange offers. Questions and requests for assistance, requests for additional copies of this prospectus or of the letter of transmittal should be directed to the exchange agent addressed as follows:

Wells Fargo Bank, National Association

By Facsimile for Eligible Institutions:	***By Registered and Certified Mail:***	***Confirm by Telephone:***
(214) 777-4086 Attention: Patrick T. Giordano	Wells Fargo Bank, NA Corporate Trust Operations MAC N9303-121 PO Box 1517 Minneapolis, MN 55480	(214) 740-1573
	By Regular Mail or Overnight Courier: Wells Fargo Bank, NA Corporate Trust Operations MAC N9303-121 Sixth & Marquette Avenue Minneapolis, MN 55479	
	In person by hand only: Wells Fargo Bank, NA 12th Floor Northstar East Building Corporate Trust Operations 608 Second Avenue South Minneapolis, MN	

Fees and Expenses

We will bear the expenses of soliciting tenders. The principal solicitation is being made by mail; however, we may make additional solicitation by telegraph, telephone or in person by our officers and regular employees and those of our affiliates.

We have not retained any dealer manager in connection with the exchange offers and will not make any payments to broker-dealers or others soliciting acceptances of the exchange offers. We will, however, pay the exchange agent reasonable and customary fees for its services and reimburse it for its related reasonable out of pocket expenses.

We will pay the cash expenses to be incurred in connection with the exchange offers. They include:

- SEC registration fees;
- Fees and expenses of the exchange agent and trustee;
- Accounting and legal fees and printing costs; and

Related fees and expenses.

Transfer Taxes

We will pay all transfer taxes, if any, applicable to the exchange of outstanding notes under the exchange offers. Each tendering holder, however, will be required to pay any transfer taxes, whether imposed on the registered holder or any other person, if a transfer tax is imposed for any reason other than the exchange of outstanding notes under the exchange offers.

Table of Contents

Consequences of Failure to Exchange Outstanding Securities

If you do not exchange your outstanding notes for exchange notes under the applicable exchange offer, the outstanding notes you hold will continue to be subject to the existing restrictions on transfer. In general, you may not offer or sell the outstanding notes except under an exemption from, or in a transaction not subject to, the Securities Act and applicable state securities laws. We do not intend to register outstanding notes under the Securities Act unless the registration rights agreement requires us to do so.

Accounting Treatment

We will record the exchange notes in our accounting records at the same carrying value as the outstanding notes. This carrying value is the aggregate principal amount of the outstanding notes, as reflected in our accounting records on the date of exchange. Accordingly, we will not recognize any gain or loss for accounting purposes in connection with the exchange offers, other than the recognition of the fees and expenses of the offering as stated under Fees and Expenses.

Other

Participation in the exchange offers is voluntary, and you should consider carefully whether to accept. You are urged to consult your financial and tax advisors in making your own decision on what action to take.

We may in the future seek to acquire any untendered outstanding notes in open market or privately negotiated transactions, through subsequent exchange offers or otherwise. We have no present plans to acquire any outstanding notes that are not tendered in the applicable exchange offer or to file a registration statement to permit resales of any untendered outstanding notes.

Table of Contents

CAUTIONARY STATEMENTS REGARDING FORWARD-LOOKING STATEMENTS

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

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

marketing of natural gas and oil;

competition in the natural gas and oil industry;

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

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

SELECTED HISTORICAL CONSOLIDATED FINANCIAL DATA

The following tables set forth selected historical consolidated financial data for the three months ended March 31, 2008 and 2007 and for the years ended December 31, 2007, 2006, 2005, 2004 and 2003. The historical financial data as of December 31, 2007 and 2006 and for the years ended December 31, 2007, 2006 and 2005 are derived from our audited consolidated financial statements and the notes thereto included in this prospectus. The unaudited condensed consolidated balance sheet data and statement of operations data at March 31, 2007 and 2008 and for the three month periods ended March 31, 2007 and 2008 are derived from our unaudited condensed combined financial statements and the notes thereto included in this prospectus. The historical financial data as of December 31, 2005, 2004 and 2003 and for the years ended December 31, 2004 and 2003 are derived from our audited consolidated financial statements which are not included in this prospectus. The selected financial data should be read in conjunction with, and is qualified in its entirety by reference to, Management s Discussion and Analysis of Financial Condition and Results of Operations and our financial statements and the notes thereto included elsewhere in this prospectus.

	Years Ended December 31,					Three Months Ended March 31,	
	2003(1)	2004(2)	2005	2006	2007	2007	2008
	(in thousands, except per share data)						
Statement of Operations Data:							
Revenues	$ 155,337	$ 175,995	$ 287,693	$ 388,242	$ 677,452	$ 149,064	$ 269,086
Expenses:							
Production	7,980	10,230	16,195	35,149	106,192	21,974	34,188
Production taxes	2,099	2,497	3,158	4,654	19,557	2,933	9,220
Drilling and services	13,847	26,442	52,122	98,436	44,211	18,777	7,169
Midstream marketing	94,620	96,180	141,372	115,076	94,253	23,420	40,418
Depreciation, depletion and amortization natural gas and crude oil	3,298	4,909	9,313	26,321	173,568	32,684	65,076
Depreciation, depletion and amortization other	5,284	7,765	14,893	29,305	53,541	10,160	17,965
General and administrative	3,705	6,554	11,908	55,634	61,780	12,468	20,994
Loss (gain) on derivative contracts	3,450	878	4,132	(12,291)	(60,732)	23,181	136,844
Loss (gain) on sale of assets	(1,284)	(210)	547	(1,023)	(1,777)	(1)	23
Total operating expenses	132,999	155,245	253,640	351,261	490,593	145,596	331,897
Income (loss) from operations	22,338	20,750	34,053	36,981	186,859	3,468	(62,811)

Other income (expense):							
Interest income	103	56	206	1,109	5,423	1,088	796
Interest expense	(1,208)	(1,678)	(5,277)	(16,904)	(117,185)	(35,429)	(25,172)
Minority interest	(96)	(262)	(737)	(296)	276	(146)	(835)
Income (loss) from equity investments	1,056	(36)	(384)	967	4,372	1,025	859
Total other expense	(145)	(1,920)	(6,192)	(15,124)	(107,114)	(33,462)	(24,352)
Income (loss) before income taxes	22,193	18,830	27,861	21,857	79,745	(29,994)	(87,163)
Income tax expense (benefit)	7,585	6,433	9,968	6,236	29,524	(10,501)	(30,538)
Income from continuing operations	14,608	12,397	17,893	15,621	50,221	(19,493)	(56,625)
Income (loss) from discontinued operations, net of tax	(85)	451	229				
Cumulative effect of accounting change	(1,636)						
Extraordinary gain		12,544					
Net income (loss)	12,887	25,392	18,122	15,621	50,221	(19,493)	(56,625)
Preferred stock dividends and accretion				3,967	39,888	8,966	9,582
Income (loss) available (applicable) to common stockholders	$ 12,887	$ 25,392	$ 18,122	$ 11,654	$ 10,333	$ (28,459)	$ (66,207)

Table of Contents

	Historical						
	Years Ended December 31,					Three Months Ended March 31,	
	2003(1)	2004(2)	2005	2006	2007	2007	2008
	(In thousands except per share data)						
Earnings Per Share Information:							
Basic							
Income (loss) from continuing operations	$ 0.26	$ 0.22	$ 0.31	$ 0.21	$ 0.46	$ (0.21)	$ (0.40)
Income from discontinued operations, net of income tax		0.01	0.01				
Extraordinary gain on acquisition		0.22					
Cumulative effect of change in accounting principle, net of income tax	(0.03)						
Preferred stock dividends				(0.05)	(0.37)	(0.10)	(0.07)
Income (loss) per share available to common stockholders	$ 0.23	$ 0.45	$ 0.32	$ 0.16	$ 0.09	$ (0.31)	$ (0.47)
Weighted average number of shares outstanding(3):	56,312	56,312	56,559	73,727	108,828	92,442	141,044
Diluted							
Income (loss) from continuing operations	$ 0.26	$ 0.22	$ 0.31	$ 0.21	$ 0.46	$ (0.21)	$ (0.40)
Income from discontinued operations, net of income tax		0.01	0.01				
Extraordinary gain on acquisition		0.22					
Cumulative effect of change in accounting principle, net of income tax	(0.03)						
Preferred stock dividends				(0.05)	(0.37)	(0.10)	(0.07)
Income (loss) per share available to common stockholders	$ 0.23	$ 0.45	$ 0.32	$ 0.16	$ 0.09	$ (0.31)	$ (0.47)
Weighted average number of shares	56,312	56,312	56,737	74,664	110,041	92,442	141,044

outstanding(3):

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

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

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

	As of December 31,					As of March 31,	
	2003	2004	2005	2006	2007	2007	2008
	(In thousands)						
Balance Sheet Data:							
Cash and cash equivalents	$ 176	$ 12,973	$ 45,731	$ 38,948	$ 63,135	$ 193,459	$ 726
Property, plant and equipment, net	$ 70,289	$ 114,818	$ 337,881	$ 2,134,718	$ 3,337,410	$ 2,274,247	$ 3,675,594
Total assets	$ 127,744	$ 197,017	$ 458,683	$ 2,388,384	$ 3,630,566	$ 2,689,004	$ 3,907,832
Long-term debt	$ 24,740	$ 59,340	$ 43,133	$ 1,066,831	$ 1,067,649	$ 1,074,254	$ 1,278,932
Redeemable convertible preferred stock	$	$	$	$ 439,643	$ 450,715	$ 449,643	$ 380,893
Total stockholders equity	$ 33,940	$ 59,330	$ 289,002	$ 649,818	$ 1,766,891	$ 932,801	$ 1,778,989
Total liabilities and stockholders equity	$ 127,744	$ 197,017	$ 458,683	$ 2,388,384	$ 3,630,566	$ 2,689,004	$ 3,907,832

Table of Contents

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

The following discussion and analysis is intended to help the reader understand our business, financial condition, results of operations, liquidity and capital resources. You should read this discussion in conjunction with our audited and unaudited consolidated financial statements and the related notes beginning on page F-1 of this prospectus.

The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for natural gas and crude oil, economic and competitive conditions, regulatory changes, estimates of proved reserves, potential failure to achieve production from development projects, capital expenditures and other uncertainties, as well as those factors discussed below and elsewhere in this prospectus. Please see Risk Factors and Cautionary Statements Regarding Forward-Looking Statements. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

The financial information with respect to the three month periods ended March 31, 2008 and March 31, 2007 that is discussed below is unaudited. In the opinion of management, this information contains all adjustments, consisting only of normal recurring accruals, necessary to state fairly the unaudited condensed consolidated financial statements. The results of operations for the interim periods are not necessarily indicative of the results of operations for the full fiscal year.

Overview of Our Company

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

On November 21, 2006, we acquired all of the outstanding membership interests in NEG Oil & Gas LLC (NEG) for total consideration of approximately $1.5 billion, excluding cash acquired. With core assets in the Val Verde and Permian Basins of West Texas, including overlapping or contiguous interests in the WTO, the NEG acquisition has dramatically increased our exploration and production segment operations. In addition to the NEG acquisition, we have completed numerous acquisitions of additional working interests in the WTO during the period from late 2005 through March 31, 2008. We also operate significant interests in the Cotton Valley Trend in East Texas, the Gulf Coast area, the Mid-Continent and the Gulf of Mexico.

During November 2007, we completed the initial public offering of our common stock. We used the proceeds from this offering to repay indebtedness outstanding under our senior credit facility as well as a note payable related to a 2007 acquisition and to fund the remainder of our 2007 capital expenditure program and a portion of our 2008 capital expenditure program.

Recent Developments

Increase in Borrowing Base. In April 2008, our senior credit facility was increased to $1.75 billion from $750 million and our borrowing base was increased to $1.2 billion from $700.0 million. The $1.2 billion borrowing base contemplated a potential future fixed income transaction not to exceed $400.0 million. As a result of our May 2008 issuance of $750.0 million of senior notes, our borrowing base was reduced to $1.1 billion.

Exchange of Senior Term Loans. On May 1, 2008, we issued $650.0 million in principal amount of 85/8% Senior Notes Due 2015 in exchange for an equal outstanding principal amount of our fixed rate term

Table of Contents

loans and $350.0 million of our Senior Floating Rate Notes Due 2014 in exchange for an equal outstanding principal amount of our variable rate term loans. The exchange was made pursuant to a private placement that commenced on March 28, 2008 and expired on April 28, 2008. The newly issued senior notes have terms that are substantially identical to those of the exchanged senior term loans, except that the senior notes have been issued with registration rights.

Conversion of Redeemable Convertible Preferred Stock. In May 2008, we converted the remaining outstanding 1,844,464 shares of our redeemable convertible preferred stock into 18,810,260 shares of our common stock as permitted under the terms of the redeemable convertible preferred stock. This conversion resulted in a one-time charge to retained earnings of $6.1 million in accelerated accretion expense related to the remaining offering costs of the 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.

Sale of Assets. In May 2008, we entered into an agreement, along with other parties, to sell substantially all of our assets located in the Piceance Basin of Colorado to a subsidiary of The Williams Companies, Inc. The total purchase price was $285 million with net proceeds to the Company of approximately $140 million, subject to closing adjustments and allocation of the sales price among multiple sellers. Assets sold included undeveloped acreage, working interests in wells, gathering and compression systems and other facilities related to the wells. The sale was completed on May 20, 2008.

Issuance of 8% Senior Notes. On May 20, 2008, we issued $750 million of our 8% Senior Notes due 2018 in a private placement. We received net proceeds of approximately $734 million from the offering. We used approximately $478 million of the net proceeds to repay all of the outstanding balance on our senior credit facility. The remaining proceeds will be used to fund the remaining unfunded portion of our $1.5 billion capital expenditures budget for 2008.

Segment Overview

We operate in four related business segments: exploration and production, drilling and oil field services, midstream gas services and other. Management evaluates the performance of our business segments based on operating income, which is defined as segment operating revenue less operating expenses and depreciation, depletion and amortization. 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.

	Year Ended December 31,			Three Months Ended March 31,	
	2007	2006	2005	2008	2007
Segment revenue:					
Exploration and production	$ 478,747	$ 106,413	$ 54,051	$ 206,922	$ 90,826
Drilling and oil field services	73,202	138,657	80,151	12,322	27,895
Midstream gas services	107,578	122,892	147,499	45,087	26,187
Other	17,925	20,280	5,992	4,755	4,156
Total revenues	677,452	388,242	287,693	269,086	149,064
Segment operating income:					
Exploration and production	198,913	17,069	14,886	(47,389)	371
Drilling and oil field services	10,473	32,946	18,295	(2,148)	5,202
Midstream gas services	6,783	3,528	4,096	32	1,350

Other	(29,310)	(16,562)	(3,224)	(13,306)	(3,455)
Total operating income (loss)	186,859	36,981	34,053	(62,811)	3,468
Interest income	5,423	1,109	206	796	1,088
Interest expense	(117,185)	(16,904)	(5,277)	(25,172)	(35,429)
Other income (expense)	4,648	671	(1,121)	24	879
Income (loss) before income taxes	$ 79,745	$ 21,857	$ 27,861	$ (87,163)	$ (29,994)

	Year Ended December 31,			Three Months Ended March 31,	
	2007	2006	2005	2008	2007
Production data:					
Natural gas (Mmcf)	51,958	13,410	6,873	19,173	10,449
Crude oil (MBbls)(1)	2,042	322	72	611	393
Combined equivalent volumes (Mmcfe)	64,211	15,342	7,305	22,839	12,807
Average daily combined equivalent volumes (Mmcfe/d)	175.9	42.0	20.0	251.0	142.3
Average prices- as reported(2):					
Natural gas (per Mcf)	$ 6.51	$ 6.19	$ 6.54	$ 7.86	$ 6.60
Crude oil (per Bbl)(1)	$ 68.12	$ 56.61	$ 48.19	$ 89.81	$ 54.06
Combined equivalent (per Mcfe)	$ 7.45	$ 6.60	$ 6.63	$ 9.00	$ 7.04
Average prices- including impact of derivative contract settlements:					
Natural gas (per Mcf)	$ 7.18	$ 7.25	$ 6.54	$ 8.32	$ 6.45
Crude oil (per Bbl)(1)	$ 68.10	$ 56.61	$ 48.19	$ 87.42	$ 54.06
Combined equivalent (per Mcfe)	$ 7.98	$ 7.52	$ 6.63	$ 9.32	$ 6.92
Drilling and oil field services:					
Number of operational drilling rigs owned at end of period	25.0	25.0	19.0	26.0	25.0
Average number of operational drilling rigs owned during the period	26.0	21.9	14.3	26.0	25.0
Average drilling revenue per rig per day(3)	$ 17,177	$ 17,034	$ 11,503	$ 17,500	$ 16,600

(1) Includes natural gas liquids.

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

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

Exploration and Production Segment

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

The primary factors affecting the financial results of our exploration and production segment are the prices we receive for our natural gas and crude oil production, the quantity of our natural gas and crude oil production and changes in the fair value of derivative contracts we use to reduce the volatility of the prices we receive for our natural gas and crude oil production. Because we are vertically integrated, our exploration and production activities affect the results of our drilling and oil field services and midstream gas services segments. The NEG acquisition in 2006 substantially increased our revenues and operating income in our exploration and production segment. However, because our working interest in the Piñon Field increased to approximately 93%, there are greater intercompany eliminations that affect the consolidated financial results of our drilling and oil field services and midstream gas services segments.

Exploration and production segment revenues increased to $206.9 million in the three months ended March 31, 2008 from $90.8 million in the three months ended March 31, 2007, an increase of 127.8%, as a result of a 78.1% increase in combined production volumes and a 27.8% increase in the combined average price we received for the natural gas and crude oil we produced. In the three month period ended March 31, 2008 we increased natural gas production by 8.8 Bcf to 19.2 Bcf and increased crude oil production by

218 MBbls to 611 MBbls from the comparable period in 2007. The total combined 10.0 Bcfe increase in production was due primarily to an increase in our average working interest in the WTO from 81% at March 31, 2007 to 93% at March 31, 2008 and successful drilling in the WTO throughout 2007 and the first quarter of 2008. The Company had 1,869 producing wells at March 31, 2008 as compared to 1,333 producing wells at March 31, 2007.

The average price we received for our natural gas production for the three month period ended March 31, 2008 increased 19.1%, or $1.26 per Mcf, to $7.86 per Mcf from $6.60 per Mcf in the comparable period in 2007. The average price received for our crude oil production increased 66.1%, or $35.75 per barrel, to $89.81 per barrel during the three months ended March 31, 2008 from $54.06 per barrel during the same period in 2007. Including the impact of derivative contract settlements, the effective price received for natural gas for the three month period ended March 31, 2008 was $8.32 per Mcf as compared to $6.45 per Mcf during the same period in 2007. Including the impact of derivative contract settlements, the effective price received for crude oil for the three month period ended March 31, 2008 was $87.42. Our derivative contracts had no impact on effective oil prices during the three months ended March 31, 2007. During 2007 and continuing into 2008, we entered into derivatives contracts to mitigate the impact of commodity price fluctuations on our 2007, 2008 and 2009 production. Our derivative contracts are not designated as accounting hedges and, as a result, gains or losses on commodity derivative contracts are recorded as an operating expense. Internally, management views the settlement of such derivative contracts as adjustments to the price received for natural gas and crude oil production to determine effective prices.

For the three months ended March 31, 2008, we had a $47.4 million operating loss in our exploration and production segment, compared to $0.4 million in operating income for the same period in 2007. Our $116.1 million increase in exploration and production revenues was offset by a $12.2 million increase in production expenses, a $32.4 million increase in depreciation, depletion and amortization, or DD&A, due to the increase in production and a $136.8 million loss on our derivative contracts. The increase in production expenses was attributable to the increase in number of operating wells we own and an increase in our average working interest in those wells. During the three month period ended March 31, 2008, the exploration and production segment reported a $136.8 million net loss on our commodity derivative positions ($7.3 million realized gain and $144.1 million unrealized loss) compared to a $23.2 million loss ($1.5 million realized loss and $21.7 million unrealized loss) in the comparable period in 2007. During 2007 and first quarter 2008, we selectively entered into natural gas and oil swaps and natural gas basis swaps in order to mitigate the effects of fluctuations in prices received for our production. Given the long term nature of our investment in the WTO development program and the relatively high level of natural gas prices compared to our budgeted prices, management believes it prudent to enter into natural gas and crude oil swaps and natural gas basis swaps for a portion of our production. Unrealized gains or losses on derivative contracts represent the change in fair value of open derivative positions during the period. The change in fair value is principally measured based on period end prices as compared to the contract price. The unrealized loss on natural gas and crude oil derivative contracts recorded in the three month period ended March 31, 2008 was attributable to an increase in average natural gas and crude oil prices at March 31, 2008 as compared to the average natural gas and crude oil prices at December 31, 2007 or the contract price for contracts entered into during the period. Future volatility in natural gas and crude oil prices could have an adverse effect on the operating results of our exploration and production segment.

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

The average price we received for our natural gas production for the year ended December 31, 2007 increased 5%, or $0.32 per Mcf, to $6.51 per Mcf from $6.19 per Mcf in 2006. The average price received for our crude oil production increased to $68.12 from $56.61 per Bbl in 2006. Including the impact of derivative contract settlements, the effective

price received for natural gas for the year ended December 31, 2007 was

$7.18 per Mcf as compared to $7.25 per Mcf during the comparable period in 2006. Our oil derivative contract settlements decreased our effective price received for oil by $0.02 per Bbl to $68.10 per Bbl for the year ended December 31, 2007. Our derivative contracts had no impact on effective oil prices during the year ended December 31, 2006.

For the year ended December 31, 2007, we had $198.9 million in operating income in our exploration and production segment, compared to $17.1 million in operating income in 2006. The $372.4 million increase in exploration and production segment revenues was partially offset by a $71.0 million increase in production expenses and a $147.2 million increase in depreciation, depletion and amortization, or DD&A. The increase in production expenses was attributable to the additional properties acquired in the NEG acquisition and operating expenses on our new wells. During the year ended December 31, 2007, the exploration and production segment reported a $60.7 million net gain on our derivative positions ($34.5 million realized gains and $26.2 million unrealized gains) compared to a $12.3 million net gain ($14.2 million realized gains and $1.9 million unrealized losses) in the comparable period in 2006. During 2007, we selectively entered into natural gas swaps and basis swaps by capitalizing on what we perceived as spikes in the price of natural gas or favorable basis differences between the NYMEX price and natural gas prices at our principal West Texas pricing point of Waha Hub. Unrealized gains or losses on derivative contracts represent the change in fair value of open derivative positions during the period. The change in fair value is principally measured based on period end prices as compared to the contract price. Future volatility in natural gas and oil prices could have an adverse effect on the operating results of our exploration and production segment.

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

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

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

gas to $5.32 per Mcf at December 31, 2006 from $8.40 per Mcf at December 31, 2005.

Estimates of net proved reserves are inherently imprecise. In order to prepare our estimates, we must analyze available geological, geophysical, production and engineering data and project production rates and

the timing of development expenditures. The process also requires economic assumptions about matters such as natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and the availability of funds. We may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond our control. Approximately 97% of our year-end reserve estimates are prepared by independent petroleum reserve engineers.

Over the past several years, higher natural gas and oil prices have led to higher demand for drilling rigs, operating personnel and field supplies and services. Higher prices have also caused increases in the costs of those goods and services. To date, the higher sales prices have more than offset the higher field costs. Our ownership of drilling rigs has also assisted us in stabilizing our overall cost structure. Given the inherent volatility of natural gas and oil prices that are influenced by many factors beyond our control, we plan our activities and budget based on conservative sales price assumptions, which generally were lower than the average sales prices received in 2007. We focus our efforts on increasing natural gas reserves and production while controlling costs at a level that is appropriate for long-term operations. Our future earnings and cash flows are dependent on our ability to manage our overall cost structure to a level that allows for profitable production.

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

Drilling and Oil Field Services Segment

We drill for our own account primarily in the WTO through our drilling and oil field services subsidiary, Lariat Services, Inc. We also drill wells for other natural gas and crude oil companies, primarily located in the West Texas region. As of March 31, 2008, our drilling rig fleet consisted of 37 operational rigs, 26 we owned directly and 11 owned by Larclay, L.P., a limited partnership in which we have a 50% interest. We also own one rig that is currently being retrofitted. Our oil field services business conducts operations that complement our drilling services operations. These services include providing pulling units, trucking, rental tools, location and road construction and roustabout services to ourselves and to third parties. Additionally, we provide under-balanced drilling systems only for our own account.

In 2006, we and Clayton Williams Energy, Inc., or CWEI, formed Larclay, L.P., which acquired twelve sets of rig components and other related equipment to assemble into completed land drilling rigs. The drilling rigs were to be used for drilling on CWEI s prospects, our prospects or for contracting to third parties on daywork drilling contracts. All of these rigs have been delivered, although one rig has not been assembled. CWEI was responsible for securing financing and the purchase of the rigs. The partnership financed 100% of the acquisition cost of the rigs utilizing a guarantee by CWEI. We operate the rigs owned by the partnership. The partnership and CWEI are responsible for all costs related to the initial construction and equipping of the drilling rigs. In the event of an operating shortfall within the partnership, we, along with CWEI, are responsible to fund the shortfall through loans to the partnership. We account for Larclay as an equity investment.

The financial results of our drilling and oil field services segment depend on many factors, particularly the demand for and the price we can charge for our services. We provide drilling services for our own account

and for others, generally on a daywork, and less often on a turnkey, contract basis. We generally assess the complexity and risk of operations, the on-site drilling conditions, the type of equipment to be used, the anticipated duration of the work to be performed and the prevailing market rates in determining the contract terms we offer.

Daywork Contracts. Under a daywork drilling contract, we provide a drilling rig with required personnel to our customer who supervises the drilling of the well. We are paid based on a negotiated fixed rate per day while the rig is used. Daywork drilling contracts specify the equipment to be used, the size of the hole and the depth of the well. Under a daywork drilling contract, the customer bears a large portion of the out-of-pocket drilling costs, and we generally bear no part of the usual risks associated with drilling, such as time delays and unanticipated costs. As of March 31, 2008, 26 of our rigs were operating under daywork contracts and 24 of these were working for our account. As of March 31, 2008, the 11 operational rigs owned by Larclay were operating under daywork contracts and six of these were working for our account. Four of the remaining operational Larclay rigs were working for CWEI as of March 31, 2008.

Turnkey Contracts. Under a typical turnkey contract, a customer will pay us to drill a well to a specified depth and under specified conditions for a fixed price, regardless of the time required or the problems encountered in drilling the well. We provide most of the equipment and drilling supplies required to drill the well. We subcontract for related services such as the provision of casing crews, cementing and well logging. Generally, we do not receive progress payments and are paid only after the well is drilled. We enter into turnkey contracts in areas where our experience and expertise permit us to drill wells more profitably than under a daywork contract. As of March 31, 2008, none of our rigs were operating under a turnkey contract.

Drilling and oil field services segment revenue decreased to $12.3 million in the three month period ended March 31, 2008 from $27.9 million in the three month period ended March 31, 2007. This resulted in an operating loss of $2.1 million in the three month period ended March 31, 2008 compared to operating income of $5.2 million in the same period in 2007. The decline in revenues and operating income is primarily attributable to an increase in the number of our rigs operating on our properties and an increase in our ownership interest in our natural gas and crude oil properties. Our drilling and oil field services segment records revenues and operating income only on wells drilled for or on behalf of third parties. The portion of drilling costs incurred by our drilling and oil field services segment relating to our ownership interest are capitalized as part of our full-cost pool. With the various WTO property acquisitions that occurred throughout 2007 and the first quarter of 2008, our average working interest has increased to approximately 93% (from 81% at March 31, 2007) in the wells we operate in the WTO, and the third-party interest has declined to less than 10%. Additionally, 24 of the 26 operational rigs we owned were working for our account at March 31, 2008, as compared to 14 of our 23 operational rigs working for our account at March 31, 2007. As a result, during the three month period ended March 31, 2008, approximately 84.6%, or $67.5 million, of our drilling and oil field service revenues were generated by work performed on our own account and eliminated in consolidation as compared to approximately 51.0%, or $29.0 million, for the comparable period in 2007. The average daily rate we received per rig of approximately $17,500, excluding revenues for related rental equipment and before intercompany eliminations, was slightly higher than the daily rate of $16,600 from the comparable period in 2007.

Drilling and oil field services segment revenue decreased to $73.2 million for the year ended December 31, 2007 from $138.7 million for the year ended December 31, 2006. Operating income decreased to $10.5 million during 2007 from $32.9 million in the same period in 2006. The decline in revenues and operating income is primarily attributable to an increase in the number of rigs operating on our properties and an increase in our ownership interest in our natural gas and oil properties. As of December 31, 2007, with the NEG acquisition and other WTO property acquisitions, our average working interest was approximately 93% in the wells we operate in the WTO, and the third-party interest has declined to less than 20%. During the year ended December 31, 2007, approximately 72% of drilling and oil field service segment revenue was generated by work performed on our own account and eliminated in consolidation as compared to approximately 34% for the comparable period in 2006. The number of drilling rigs we owned increased

19% to an average of 26 rigs during 2007 from an average of 21.9 rigs in 2006. The average daily rate we received per rig of $17,177, excluding revenues for related rental equipment and before intercompany eliminations, was

essentially unchanged from 2006. Our rig utilization rate was 90%, representing 1,095 stacked rig days in 2007. The decline in operating income was principally attributable to the increase in the number and working interest ownership in wells drilled for our own account.

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

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

Midstream Gas Services Segment

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

Midstream gas services segment revenue for the three months ended March 31, 2008 was $45.1 million compared to $26.2 million in the comparable period of 2007. The quarterly increase in midstream gas services revenues is attributable to larger third-party volumes transported and marketed through our gathering systems during the three months ended March 31, 2008 as compared to the same period in 2007. We generally charge a flat fee per unit transported and charge a percentage of sales for marketed volumes.

Midstream gas services segment revenue for the year ended December 31, 2007 was $107.6 million compared to $122.9 million in 2006. The decrease in midstream gas services revenues is attributable to the increase in our working interest in the WTO as a result of the NEG and other acquisitions.

Midstream gas services segment revenue decreased $24.6 million for the year ended December 31, 2006 from $147.5 million in 2005 to $122.9 million in 2006. The NEG acquisition significantly decreased our midstream gas services revenue as more gas was transported for our own account. We do not record midstream gas revenue for transportation, treating and processing of our own gas. Prior to the NEG acquisition, transportation, treating and processing of gas for NEG was recorded as midstream gas services revenue. Operating income increased $3.3 million in 2007 to $6.8 million due to lower gas prices paid and an increase in marketing and transportation for our own account. Operating income decreased to $3.5 million in 2006 from $4.1 million in the 2005 period, primarily due to the NEG acquisition and start-up operating expenses for our Sagebrush processing plant in 2006. The Sagebrush plant was placed into full operation during May 2007. We have the contractual right to periodically increase fees we receive for transportation and processing based on certain indexes.

35

Table of Contents

Other Segment

Our other segment consists primarily of our CO_2 gathering and sales operations, corporate operations and other investments. We conduct our CO_2 gathering and sales operations through our wholly owned subsidiary, SandRidge CO_2, LLC (formerly operated through PetroSource Energy Company, LLC). SandRidge CO_2 gathers CO_2 from natural gas treatment plants located in West Texas and transports and sells this CO_2 for use in our and third parties tertiary oil recovery operations. The operating loss in the other segment was $13.3 million for the three months ended March 31, 2008 as compared to a loss of $3.5 million during the same period in 2007. The increase is primarily attributable to significant increases in corporate and support staff throughout 2007 and the first quarter of 2008.

Results of Operations

Three months ended March 31, 2008 compared to the three months ended March 31, 2007

Revenue. Total revenue increased 80.5% to $269.1 million for the three months ended March 31, 2008 from $149.1 million in the same period in 2007. This increase was due to a $115.3 million increase in natural gas and crude oil sales. Lower drilling and oil field services revenues partially offset the increases noted in midstream gas services and other segments.

	Three Months Ended March 31,			
	2008	2007	$ Change	% Change
		(In thousands)		
Revenue:				
Natural gas and crude oil	$ 205,487	$ 90,176	$ 115,311	127.9%
Drilling and services	12,334	27,895	(15,561)	(55.8)%
Midstream and marketing	46,409	26,187	20,222	77.2%
Other	4,856	4,806	50	1.0%
Total revenues	$ 269,086	$ 149,064	$ 120,022	80.5%

Total natural gas and crude oil revenues increased $115.3 million to $205.5 million for the three months ended March 31, 2008 compared to $90.2 million for the same period in 2007, primarily as a result of an increase in natural gas and crude oil production volumes and prices received for our production. Total natural gas production increased 83.5% to 19,173 Mmcf in 2008 compared to 10,449 Mmcf in 2007, while crude oil production increased 55.5% to 611 MBbls in 2008 from 393 MBbls in 2007. The increase was due to our successful drilling in the WTO and an increased working interest in 2008 in the WTO as compared to the same period in 2007. The average price received, excluding the impact of derivative contracts, for our natural gas and crude oil production increased 27.8% in the 2008 period to $9.00 per Mcfe compared to $7.04 per Mcfe in 2007.

Drilling and services revenue decreased 55.8% to $12.3 million for the three months ended March 31, 2008 compared to $27.9 million in the same period in 2007. The decline in revenues is due to an increase in the number of company-owned rigs operating on company-owned natural gas and crude oil properties and the increase in working interest in these properties. Additionally, the average daily revenue per rig, after considering the effect of the

elimination of intercompany usage, increased to approximately $17,500 per day during the first three months of 2008 as compared to an average rate of approximately $16,600 per day during the same period in 2007.

Midstream and marketing revenue increased $20.2 million, or 77.2%, with revenues of $46.4 million in the three month period ended March 31, 2008 as compared to $26.2 million in the three month period ended March 31, 2007. This increase is due primarily to larger production volumes transported and marketed, during the three months ended March 31, 2008 as compared to the same period in 2007, for the third parties with ownership in our wells or ownership in other wells connected to our gathering systems.

Table of Contents

Other revenue increased to $4.9 million for the three months ended March 31, 2008 from $4.8 million for the same period in 2007. Other revenue is generated primarily by our CO_2 gathering and sales operations.

Operating Costs and Expenses. Total operating costs and expenses increased to $331.9 million for the three months ended March 31, 2008 compared to $145.6 million for the same period in 2007 due to increases in production-related costs, general and administrative expenses as a result of an increase in corporate staff, depreciation, depletion and amortization and losses on derivative contracts. These increases were partially offset by a decrease in expenses attributable to our drilling and services.

	Three Months Ended March 31,			
	2008	2007	$ Change	% Change
		(In thousands)		
Operating costs and expenses:				
Production	$ 34,188	$ 21,974	$ 12,214	55.6%
Production taxes	9,220	2,933	6,287	214.4%
Drilling and services	7,169	18,777	(11,608)	(61.8)%
Midstream and marketing	40,418	23,420	16,998	72.6%
Depreciation, depletion, and amortization natural gas and crude oil	65,076	32,684	32,392	99.1%
Depreciation, depletion and amortization other	17,965	10,160	7,805	76.8%
General and administrative	20,994	12,468	8,526	68.4%
Loss on derivative contracts	136,844	23,181	113,663	490.3%
Loss (gain) on sale of assets	23	(1)	24	2,400.0%
Total operating costs and expenses	$ 331,897	$ 145,596	$ 186,301	128.0%

Production expense includes the costs associated with our production activities, including, but not limited to, lease operating expense and processing costs. Production expenses increased $12.2 million primarily due to an increase in the number of wells in which we have a working interest. We owned working interests in 1,869 producing wells at March 31, 2008 compared to 1,333 producing wells at March 31, 2007. Production taxes increased $6.3 million, or 214.4%, to $9.2 million primarily due to the increase in production and the increased prices received for production during the three months ended March 31, 2008.

Drilling and services expenses decreased 61.8% for the three months ended March 31, 2008 as compared to the same period in 2007 primarily because of the increase in the number and working interest ownership of the wells we drilled for our own account.

Midstream and marketing expenses increased $17.0 million or 72.6% to $40.4 million due to larger production volumes transported and marketed during the three months ended March 31, 2008 on behalf of third parties than during the comparable period in 2007.

DD&A for our natural gas and crude oil properties increased to $65.1 million for the three months ended March 31, 2008 from $32.7 million in the same period in 2007. Our DD&A per Mcfe increased $0.30 to $2.85 in the first quarter of 2008 from $2.55 in the comparable period in 2007. The increase is primarily attributable to an increase in our

depreciable properties, higher future development costs and increased production. Our production increased 78.1% to 22.8 Bcfe from 12.8 Bcfe in 2007.

DD&A for our other assets consists primarily of depreciation of our drilling rigs, midstream gathering and compression facilities and other equipment. The increase in DD&A for our other assets was attributable primarily to higher carrying costs of our rigs due to upgrades and retrofitting and our midstream gathering and processing assets due to upgrades made throughout 2007. We calculate depreciation of property and equipment using the straight-line method over the estimated useful lives of the assets, which range from three to 25 years. Our drilling rigs and related oil field services equipment are depreciated over an average seven-year useful life.

Table of Contents

General and administrative expenses increased $8.5 million to $21.0 million for the three months ended March 31, 2008 from $12.5 million for the comparable period in 2007. The increase was principally attributable to an $8.8 million increase in corporate salaries and wages due to a significant increase in corporate and support staff. As of March 31, 2008, we had 2,385 employees as compared to 1,746 at March 31, 2007. General and administrative expenses include non-cash stock compensation expense of $3.2 million for the three months ended March 31, 2008 as compared to $1.1 million for the comparable period in 2007. The increases in salaries and wages as well as stock compensation were partially offset by $3.2 million in capitalized general and administrative expenses for the three months ended March 31, 2008. There were no general and administrative expenses capitalized during the three months ended March 31, 2007.

For the three month period ended March 31, 2008, we recorded a loss of $136.8 million ($144.1 million unrealized loss and $7.3 million realized gain) on our derivative contracts compared to a $23.2 million loss ($21.7 million unrealized loss and $1.5 million realized loss) for the comparable period in 2007. During 2007 and the first three months of 2008, we selectively entered into natural gas and crude oil swaps and basis swaps in order to mitigate the effects of fluctuations in prices received for our production. Given the long-term nature of our investment in the WTO development program and the relatively high level of natural gas prices compared to budgeted prices, we believe it is prudent to enter into natural gas swaps and basis swaps for a portion of our production. Unrealized gains or losses on natural gas and crude oil derivative contracts represent the change in fair value of open derivative positions during the period. The change in fair value is principally measured based on period end prices as compared to the prior period end prices or contract price for contracts entered into during the period. The unrealized loss recorded in the three month period ended March 31, 2008 related to natural gas and crude oil commodities was attributable to an increase in average natural gas and crude oil prices at March 31, 2008 as compared to the average natural gas and crude oil prices at December 31, 2007 or the contract price for contracts entered into during the period.

Other Income (Expense). Total other expense decreased to $24.4 million in the three month period ended March 31, 2008 from $33.5 million in the three month period ended March 31, 2007. The decrease is reflected in the table below.

	Three Months Ended March 31,			
	2008	**2007**	**$ Change**	**% Change**
		(In thousands)		
Other income (expense):				
Interest income	$ 796	$ 1,088	$ (292)	(26.8)%
Interest expense	(25,172)	(35,429)	10,257	(29.0)%
Minority interest	(835)	(146)	(689)	471.9%
Income from equity investments	859	1,025	(166)	(16.2)%
Total other expense	(24,352)	(33,462)	9,110	(27.2)%
Loss before income tax expense (benefit)	(87,163)	(29,994)	(57,169)	190.6%
Income tax expense (benefit)	(30,538)	(10,501)	(20,037)	190.8%
Net loss	$ (56,625)	$ (19,493)	$ (37,132)	190.5%

Interest income decreased to $0.8 million for the three months ended March 31, 2008 from $1.1 million for the same period in 2007. This decrease was generally due to lower excess cash levels during the three months ended March 31, 2008 as compared to the same period in 2007.

Interest expense decreased to $25.2 million for the three months ended March 31, 2008 from $35.4 million for the same period in 2007. This decrease was primarily attributable to the expensing, in March 2007, of approximately $12.5 million in unamortized debt issuance costs related to our senior bridge facility at the time it was repaid. Also contributing slightly to the decrease for the three months ended March 31, 2008 was an $0.8 million unrealized gain related to our interest rate swap. These decreases were partially offset by increased interest expense during the three months ended March 31, 2008 due to higher average debt balances outstanding during that period as compared to the same period in 2007.

During the three months ended March 31, 2008, we reported income from equity investments of $0.9 million as compared to $1.0 million in the comparable period in 2007.

We reported an income tax benefit of $30.5 million for the three months ended March 31, 2008, as compared to a benefit of $10.5 million for the same period in 2007. The current period income tax benefit represents an effective income tax rate of 35% which is unchanged from the same period in 2007.

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

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

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

	Year Ended December 31,			
	2007	2006 (In thousands)	$ Change	% Change
Revenue:				
Natural gas and crude oil	$ 477,612	$ 101,252	$ 376,360	371.7%
Drilling and services	73,197	139,049	(65,852)	(47.4)%
Midstream and marketing	107,765	122,896	(15,131)	(12.3)%
Other	18,878	25,045	(6,167)	(24.6)%
Total revenues	$ 677,452	$ 388,242	$ 289,210	74.5%

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

Drilling and services revenue decreased 47% to $73.2 million in 2007 compared to $139.0 million in 2006. The decline in revenues is primarily attributable to an increase in the number of rigs operating on our properties and an

increase in our ownership interest in our natural gas and oil properties. The number of rigs we owned increased to 26.0 (average for the year ended December 31, 2007) in 2007 compared to 21.9 in 2006, an increase of 19%, and the average daily revenue per rig, after considering the effect of the elimination of intercompany usage, was essentially unchanged at $17,177 per day.

Midstream and marketing revenue decreased $15.1 million, or 12%, with revenues of $107.8 million for the year ended December 31, 2007, as compared to $122.9 million in 2006. The NEG acquisition significantly decreased our midstream gas services revenues as more gas was transported for our own account. Prior to the acquisition, transportation, treating and processing of gas for NEG was recorded as midstream gas services revenue. We have the contractual right to periodically increase fees we receive for transportation and processing based on certain indexes.

Table of Contents

Other revenue decreased to $18.9 million during 2007 from $25.0 million in 2006. The decrease was primarily due to the sale of various non-energy related assets to our former President and Chief Operating Officer. Revenues related to these assets are included in the 2006 period prior to their sale in August 2006. This decrease was slightly offset by an increase in revenues generated by our CO_2 operations.

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

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

Production expense includes the costs associated with our exploration and production activities, including, but not limited to, lease operating expense and processing costs. Production expenses increased $71.0 million due to increased production from our 2007 drilling activity and the addition of the NEG properties. The remainder of the increase was due to an increase in lease operating expenses due to an increase in the number of wells we operate. Production taxes increased $14.9 million, or 320%, to $19.6 million primarily due to increased gas production as a result of our 2007 drilling activity and the addition of the NEG properties in 2006.

Drilling and services and midstream and marketing expenses decreased 55% and 18% respectively, during 2007 as compared to 2006 primarily because of the increase in the number and working interest ownership of the wells we drilled for our own account.

DD&A for our natural gas and crude oil properties increased to $173.6 million during 2007 from $26.3 million in 2006. Our DD&A per Mcfe increased $0.98 to $2.70 from $1.72 in 2006. The increase is primarily attributable to our 2007 capital expenditures and the NEG acquisition, which increased our depreciable properties by the purchase price plus future development costs and increased production. Our production increased 320% to 64.2 Bcfe from 15.3 Bcfe in 2006.

DD&A for our other assets consists primarily of depreciation of our drilling rigs, natural gas plants and other equipment. The $24.2 million increase in DD&A other was due primarily to our increased investments in rigs, other oilfield services equipment and midstream assets. During 2006 and 2007, capital expenditures for drilling rigs, other oilfield services equipment and midstream assets were $293 million on a combined basis. We calculate depreciation of property and equipment using the straight-line method over the estimated useful lives of the assets, which range from three to 25 years. Our drilling rigs and related oil field services equipment are depreciated over an average seven-year useful life.

Table of Contents

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

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

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

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

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

Interest expense increased to $117.2 million during 2007, from $16.9 million in 2006. This increase was attributable to increased average debt balances. To finance the NEG acquisition, we entered into a $750 million senior credit facility, which had an initial borrowing base of $300 million, and an $850 million senior bridge facility. In March 2007, we entered into a $1.0 billion senior term loan and sold 17.8 million shares of common stock in a private placement. A portion of the proceeds from the senior unsecured term loan was used to repay the bridge loan. Please read Liquidity and Capital Resources.

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

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

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

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

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

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

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

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

Midstream and marketing revenue decreased $24.2 million from 2005 with revenues of $122.9 million during the year ended December 31, 2006 as compared to $147.1 million in 2005. We do not record midstream and marketing

revenues for marketing, transportation, treating and processing of our own gas. The NEG acquisition significantly decreased our midstream gas services revenues as more gas was transported and marketed for our own account. Prior to the NEG acquisition, transportation, treating and processing of gas for NEG was recorded as midstream and marketing revenue. We have the contractual right to periodically increase fees we receive for transportation and processing based on certain indexes.

Other revenues increased $14.8 million to $25.0 million in 2006 from $10.2 million in 2005. The increase was primarily attributable to an increase of $12.0 million in CO_2 and tertiary oil recovery revenues. In December 2005, we acquired an additional equity interest in PetroSource which increased our ownership interest to 86.5%, resulting in the consolidation of PetroSource commencing in the fourth quarter of 2005. We recorded PetroSource revenues for the full year in 2006. The remainder of the increase was attributable to

Table of Contents

additional administration fees collected from operating natural gas and oil wells and lease acreage income received as a result of an increase in the number of wells, an increase in overhead rates and an increase in leasing activities. Approximately $0.9 million of the increase was related to an increase of revenue from a shopping center that was sold in 2006.

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

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

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

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

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

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

DD&A relating to our natural gas and oil properties increased 183% to $26.3 million in 2006 from $9.3 million in 2005. The increase was primarily attributable to a 110% increase in year-over-year production and a 37% increase in DD&A per unit of production. The average DD&A per Mcfe was $1.68 for the year ended December 31, 2006 as compared to $1.23 in 2005. The increase in the DD&A rate was attributable to the NEG acquisition which added significantly higher reserves at a higher cost per Mcfe.

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

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

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

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

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

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

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

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

Table of Contents

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

Liquidity and Capital Resources

Summary

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

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

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

As of March 31, 2008, our cash and cash equivalents were $0.7 million, and we had approximately $462.3 million available under our senior credit facility. Amounts outstanding under our senior credit facility at March 31, 2008 totaled $215.0 million. As of March 31, 2008, we had $1.3 billion in total debt outstanding.

Capital Expenditures

We make and expect to continue to make substantial capital expenditures in the exploration, development, production and acquisition of natural gas and crude oil reserves.

Our capital expenditures by segment were:

	Year Ended December 31,			Three Months Ended March 31,	
	2007	2006	2005	2008	2007
			(In thousands)		
Capital Expenditures:					
Exploration and production	$ 1,046,552	$ 170,872	$ 61,227	$ 354,765	$ 127,582
Drilling and oil field services	123,232	89,810	43,730	17,921	41,242

Midstream gas services	63,828	16,975	25,904	38,721	9,543
Other	47,236	28,884	3,735	7,243	