Denbury

2013 Annual Report

& GROWTH INCOME

Table of Contents

Forward-Looking Statements

The data contained in this annual report that are not historical facts are forward-looking statements that involve a number of risks and uncertainties. Such statements may relate to, among other things: long-term strategy; anticipated levels of future dividends and rate of dividend growth; forecasts of capital expenditures, drilling activity and development activities; timing of carbon dioxide (CO_2) injections and initial production response to such tertiary flooding projects; estimated timing of pipeline construction or completion or the cost thereof; dates of completion of to-be-constructed industrial plants and their first date of capture of anthropogenic CO_2; estimates of costs, forecasted production rates or peak production rates and the growth thereof; estimates of hydrocarbon reserve quantities and values, CO_2 reserves, helium reserves, future hydrocarbon prices or assumptions; future cash flows or uses of cash, availability of capital or borrowing capacity; rates of return and overall economics; estimates of potential or recoverable reserves and anticipated production growth rates in our CO_2 models; estimated production and capital expenditures for full-year 2014 and periods beyond; and availability and cost of equipment and services. These forward-looking statements are generally accompanied by words such as "estimated", "preliminary", "projected", "potential", "anticipated", "forecasted", "expected", "assume" or other words that convey the uncertainty of future events or outcomes. These statements are based on management's current plans and assumptions and are subject to a number of risks and uncertainties as further outlined in our most recent Form 10-K and Form 10-Q filed with the SEC. Therefore, actual results may differ materially from the expectations, estimates or assumptions expressed in or implied by any forward-looking statement herein made by or on behalf of the Company.

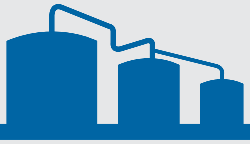
Cautionary Note to U.S. Investors — Current SEC rules regarding oil and gas reserve information allow oil and gas companies to disclose in filings with the SEC not only proved reserves, but also probable and possible reserves that meet the SEC's definitions of such terms. We disclose only proved reserves in our filings with the SEC. Denbury's proved reserves as of December 31, 2013 were estimated by DeGolyer & MacNaughton, an independent petroleum engineering firm. In this annual report, we make reference to probable and possible reserves, some of which have been estimated by our independent engineers and some of which have been estimated by Denbury's internal staff of engineers. In this annual report, we also refer to estimates of original oil in place, resource or reserves "potential", barrels recoverable, or other descriptions of volumes potentially recoverable, which in addition to reserves generally classifiable as probable and possible (2P and 3P reserves), include estimates of reserves that do not rise to the standards for possible reserves, and which SEC guidelines strictly prohibit us from including in filings with the SEC. These estimates, as well as the estimates of probable and possible reserves, are by their nature more speculative than estimates of proved reserves and are subject to greater uncertainties, and accordingly the likelihood of recovering those reserves is subject to substantially greater risk.

DISCIPLINED GROWTH

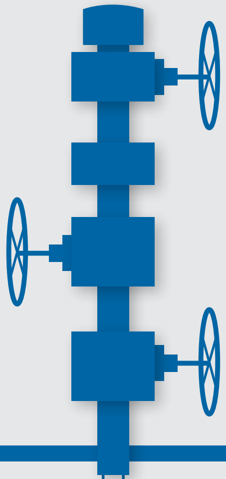
Denbury is a growing, dividend-paying, domestic oil and natural gas company. Our primary focus is on enhanced oil recovery utilizing carbon dioxide (CO_2 EOR). Our goal is to increase the value of acquired properties through a combination of exploitation, drilling and proven engineering extraction practices, with the most significant emphasis relating to tertiary recovery operations.

Denbury's CO_2 Cycle

STEP 1 CO_2 SOURCES & CAPTURE

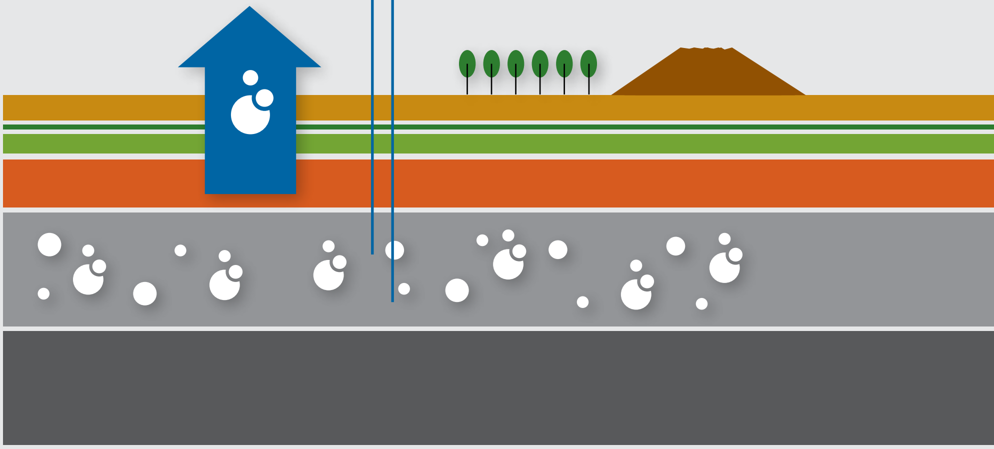


The first step in implementing a CO_2 EOR project is to secure access to substantial volumes of CO_2. We source our CO_2 from both naturally occurring underground reservoirs and anthropogenic (man-made) sources. The proven CO_2 reserves associated with our naturally occurring sources are located in Jackson Dome in Mississippi and LaBarge Field in Wyoming. We source our anthropogenic CO_2 from industrial facilities which capture, purify, dry and then compress the CO_2 for delivery into our pipeline network.



~9.3 TRILLION CUBIC FEET GROSS PROVED CO_2 RESERVES AS OF 12/31/2013

~70 MILLION CUBIC FEET PER DAY ANTHROPOGENIC CO_2



STEP 2 CO_2 TRANSPORTATION

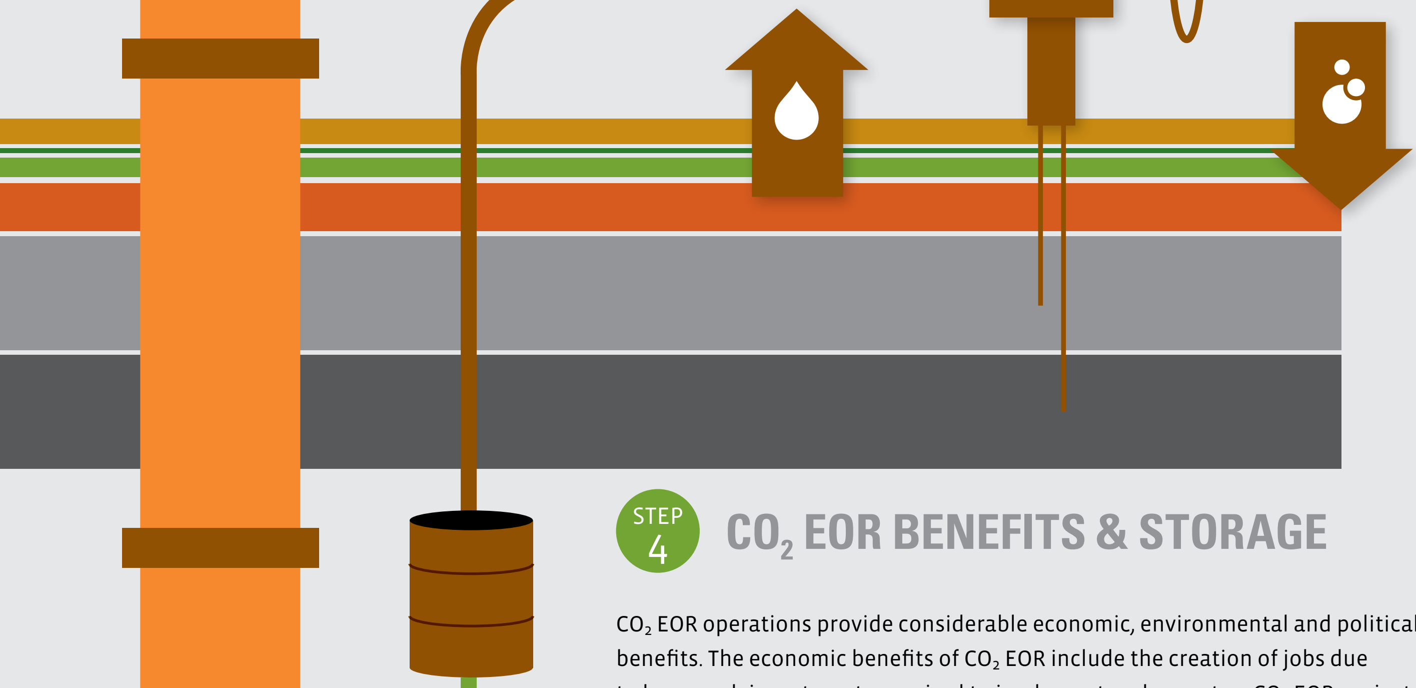
The second step in implementing a CO_2 EOR project is transporting the CO_2 from the source to the oil field. We operate or control over 1,100 miles of CO_2 pipelines and are continually expanding this network to transport natural and anthropogenic CO_2 to our tertiary fields. We currently utilize ~ 70 million cubic feet of anthropogenic CO_2 per day and anticipate an additional ~115 million cubic feet of anthropogenic CO_2 per day from currently planned or future construction of facilities in our Gulf Coast region.

OVER 1,100 MILES CARBON DIOXIDE PIPELINE

STEP 3 CO_2 INJECTION

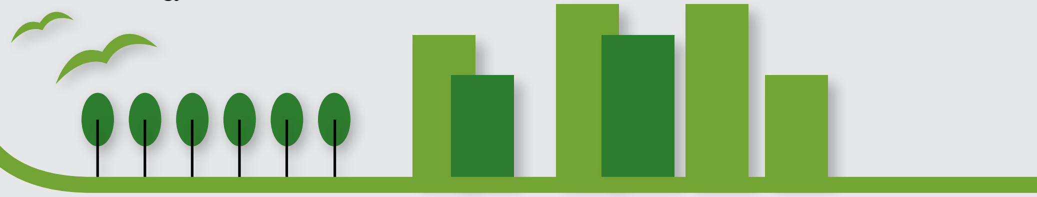
The third step in implementing a CO_2 EOR project is to inject the carbon dioxide into the oil-bearing reservoir through a wellbore. The injected CO_2 moves through the reservoir, mixing with the crude oil trapped there. The CO_2 acts to separate the oil from the reservoir rock and increase the oil's mobility within the reservoir. The mixture is driven through the formation into a producing wellbore, where it then comes to the surface, increasing the field's oil production. To date, our CO_2 EOR operations have resulted in the gross production of over 100 million barrels of otherwise stranded oil.

38,477 Bbls/d TERTIARY PRODUCTION IN 2013



STEP 4 CO_2 EOR BENEFITS & STORAGE

CO_2 EOR operations provide considerable economic, environmental and political benefits. The economic benefits of CO_2 EOR include the creation of jobs due to large cash investments required to implement and operate a CO_2 EOR project along with tax payments to local governments. Our CO_2 EOR operations also provide an environmentally responsible method of utilizing and ultimately storing CO_2 in underground oil reservoirs while also making our nation more energy secure.



Dear Fellow Shareholders:

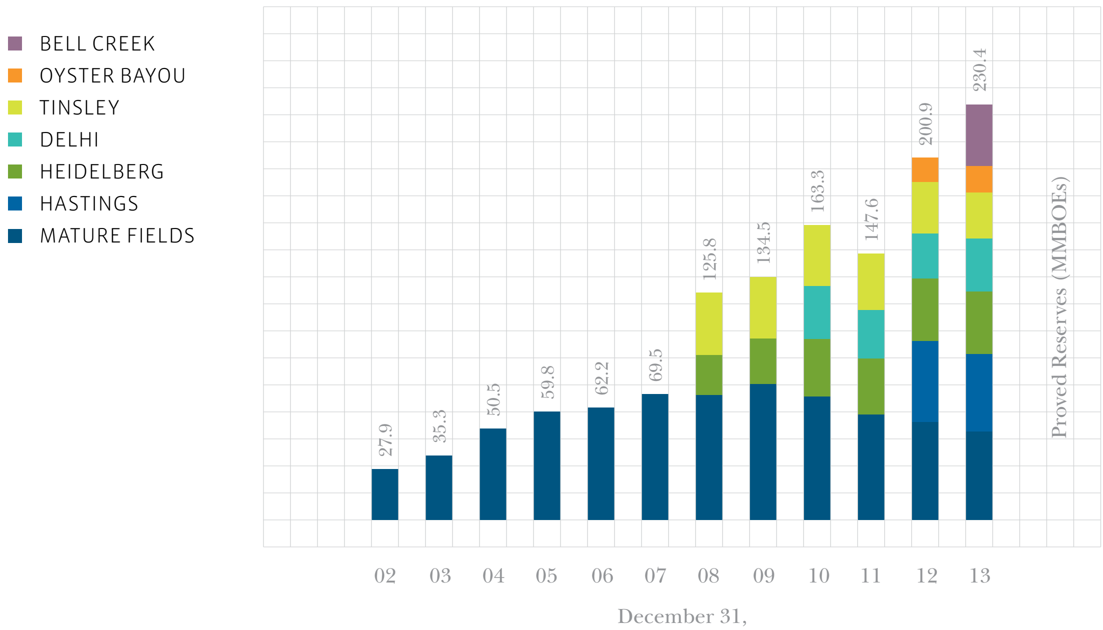
During 2013, we started the transition of our company from one focused purely on growth to one that supplements both **Growth & Income** (dividends), the theme of this year's annual report. We are able to do this because of the unique production and cash flow profile of our assets, which are all either current carbon dioxide enhanced oil recovery ("CO_2 EOR") projects, future CO_2 EOR projects or assets that produce much of the CO_2 that we use in our projects. We anticipate that our unique capability among oil and gas independents will enhance shareholder value and returns in the coming years.

In preparation for this transition to **Growth & Income**, over the last few years we made a series of tax efficient acquisitions and dispositions that sharpened our operational focus and made us a pure CO_2 EOR play.

Since CO_2 EOR is limited to areas with large CO_2 quantities, our ownership of significant CO_2 resources and pipeline infrastructure needed to transport CO_2 gives us a significant competitive advantage in the areas in which we operate. We have chosen to utilize and maximize our strategic advantage, and therefore have made CO_2 EOR our core strategy and business.

To enable the expansion of our strategy from growth to **Growth & Income**, we modified our future development plans and flattened out our anticipated annual capital spending levels for the remainder of the decade. This adjustment, combined with our view that these changes would not significantly reduce our anticipated oil and gas production and reserve growth rates, allowed us to bring forward our free cash flow by a few years. This, in turn, allowed us to accelerate our objective of providing returns to our shareholders through cash dividend payments.

Proved Tertiary Reserves[1]



(1) Proved tertiary reserves based on SEC pricing for the respective years.

With the declaration of our first-ever cash dividend on January 28, 2014, we began the process of distributing free cash flow generated from our operations to shareholders. Our first quarterly dividend of $0.0625 per common share, or a rate of $0.25 per share on an annualized basis, was paid to stockholders on March 25, 2014. Based on our current financial projections and commodity price outlook, we expect to grow our regular annual dividend rate to between $0.50 per share and $0.60 per share in 2015 and at a sustainable rate thereafter.

Of course, the expansion of our shareholder return strategy to include both **Growth & Income** is made possible by the many accomplishments of our operations team over the last few years. Let me touch on a few of these achievements over the past twelve months:

» We delivered average production of 70,243 barrels of oil equivalent per day in 2013, which was just slightly above the mid-point of the estimated range we presented in the prior year. Our tertiary oil production increased by 9% between 2012 and 2013. Our non-tertiary production, after the closing of our Cedar Creek Anticline acquisition in March of 2013, was down only modestly from levels prior to our Bakken area asset sale and exchange in late 2012. Our tertiary production growth in 2013 was driven by our newest CO_2 floods at Oyster Bayou and Hastings fields in the Houston area, and we anticipate additional growth at both of these fields in 2014. Going forward, we expect to deliver 4% to 8% annual production growth through the end of this decade without needing to acquire any additional properties.

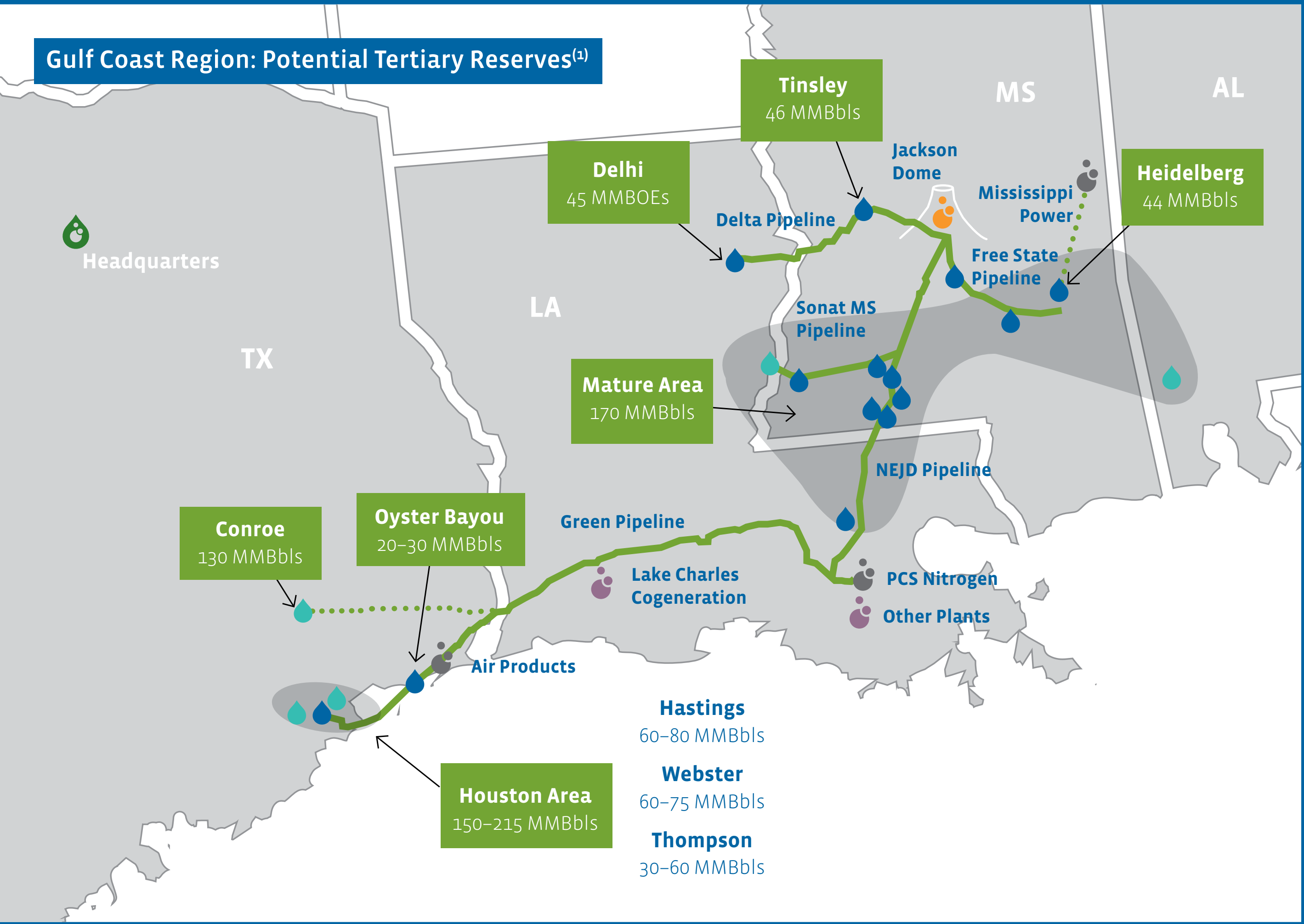
FIRST
CASH DIVIDEND PAID IN 2014

The first cash dividend in Denbury's history was paid to stockholders on March 25, 2014, making the expansion of the Company's shareholder value proposition to include quarterly cash dividends. We remain focused on developing our significant inventory of enhanced oil recovery projects in order to increase shareholder value.

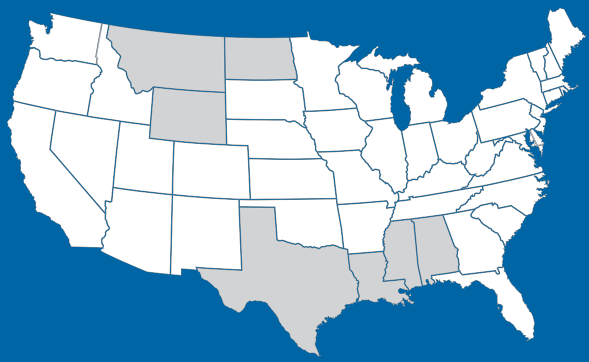
» We delivered our first tertiary oil production and proved reserves in the Rocky Mountain region. Since establishing our position in the Rocky Mountain region in 2010, our team has worked diligently to initiate our first CO_2 flood in the region. The milestones we have attained since late 2012 include: completion of the 20-inch Greencore Pipeline in Wyoming, our first CO_2 pipeline in the Rocky Mountain region; the first receipt, delivery, and injection of CO_2 into Bell Creek and Grieve fields; the first tertiary oil production at Bell Creek Field; and the completion of an interconnect between a third party's CO_2 pipeline and our Greencore Pipeline, which allows us to transport our CO_2 volumes from ExxonMobil's Shute Creek gas processing plant to Bell Creek Field. With tertiary production now established and growing in the Rocky Mountain region, we look forward to the continued expansion of our tertiary operations in the region, at both Bell Creek Field and Grieve Field.

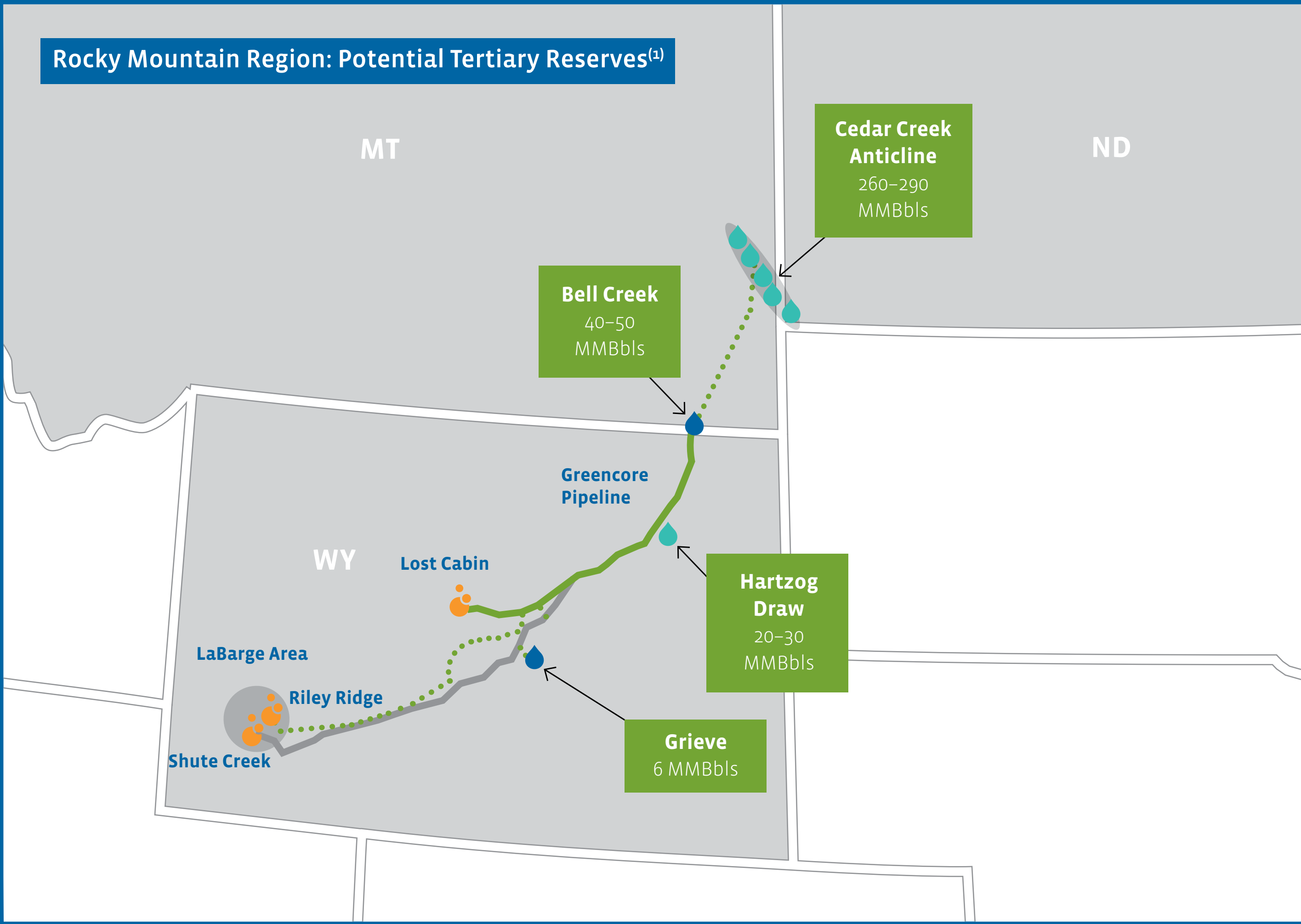
Tertiary Operations Map

Our oil and natural gas properties are concentrated in the Gulf Coast and Rocky Mountain regions of the United States. Currently our properties with proved and producing reserves in the Gulf Coast region are situated in Mississippi, Texas, Louisiana and Alabama, and in the Rocky Mountain region in Montana, North Dakota and Wyoming. Our primary focus is using CO_2 in EOR and we expect the development plan for our current portfolio of CO_2 EOR projects will allow us to grow our oil production for the remainder of the decade.



Tertiary & Total Company Potential (MMBOEs)	
Tertiary	
Proved[1]	230
Potential[2]	680
Produced-to-Date[3]	85
Total Tertiary[2]	995
Total Company Potential[4]	1,250





- Headquarters
- Existing Denbury CO_2 Pipelines
- Denbury Proposed CO_2 Pipelines
- CO_2 Pipelines Not Owned or Operated by Denbury
- Denbury CO_2 EOR Fields
- Denbury Future CO_2 EOR Fields
- CO_2 Resources Owned or Contracted
- Anthropogenic CO_2 Sources: Producing or Pending Startup
- Anthropogenic CO_2 Sources: Contracted with Future Construction

(1) Potential, proved and produced-to-date tertiary reserves estimated as of 12/31/13 based on a range of recovery factors. Proved reserves based on year-end 12/31/13 SEC reporting.
(2) Using mid-points of ranges.
(3) Produced-to-date is cumulative tertiary production through 12/31/13.
(4) Proved and potential conventional and tertiary reserves including other conventional reserves estimated as of 12/31/13 based on a range of recovery factors. Excludes tertiary production to date.

- We increased our proved oil and natural gas reserves to 468 million barrels of oil equivalent ("MMBOE") as of December 31, 2013, compared to 409 MMBOE at December 31, 2012. We added 85 MMBOE of estimated proved reserves during 2013, including tertiary reserves of 34 MMBOE at Bell Creek Field during the fourth quarter, non-tertiary reserves of 42 MMBOE from the acquisition of additional interests in CCA during the first quarter, and 9 MMBOE of other additions or revisions. We estimate our total proved and potential reserves at December 31, 2013, were 1,250 MMBOE, including an estimated 910 MMBOE associated with the planned future CO_2 EOR development of fields we currently operate. We plan to convert these potential reserves to proved reserves as we develop these oil fields.

- We placed our Riley Ridge gas processing facility into service. We acquired our initial interest in the Riley Ridge gas processing facility and the LaBarge Field in southwestern Wyoming in 2010 with the goal of making it our "Jackson Dome" of the Rockies. LaBarge Field is estimated to hold significantly more CO_2 than Jackson Dome, but it is mixed with other gases, including methane and helium. With the startup of the plant and our sales of both methane and helium, we will generate cash flow on our investment, although the bigger prize will be realized later this decade when we add CO_2 separation equipment, connect this plant to our existing CO_2 pipelines, and make Riley Ridge our anchor source of CO_2 in the Rocky Mountain region.

- We purchased and used man-made CO_2 in our operations. Starting in late 2012, we began purchasing and utilizing anthropogenic (man-made) CO_2 in our tertiary operations. In the Gulf Coast region, we are currently receiving CO_2 from two plants and anticipate, adding a third source in 2014. We expect the new facility to be our largest man-made source in the region, with other sources expected throughout the remainder of this decade. These projects illustrate our unique ability to use and store captured CO_2 that would otherwise be released into the atmosphere.

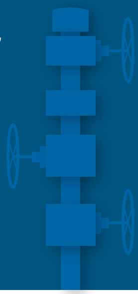
While we had many accomplishments in 2013, we did face several challenges, particularly at Delhi Field in northern Louisiana. In June, a release of well fluids, consisting of a mixture of carbon dioxide, saltwater, natural gas and oil, was discovered and reported within Delhi Field. We immediately took remedial action to stop the release and contain and recover well fluids in the affected area. We have determined that the release originated from one or more wells in the affected area of the field that we believe had previously been improperly plugged and abandoned by a prior operator of the field. While we completed our remediation efforts during the fourth quarter of 2013, the halting of CO_2 injections into the directly impacted area reduced the field's oil production and required significant corporate resources. We have taken numerous steps to mitigate the risk of something similar occurring in the future, including a more thorough review of plugged and abandoned wells, more stringent criteria for what is an acceptable plugged and abandoned well, and assignment of additional, dedicated staff and capital resources to administer this program. I am confident that the lessons learned and applied from the incident will make Denbury a better company in the future.

On the financial front, we generated $1.36 billion of cash flow from operations, more than enough to fund the $1.14 billion we spent on oil and natural gas development, CO_2 supply, pipelines, and plant capital expenditures. The excess cash flow was used to partially fund our common stock repurchase program, which our Board first authorized in 2011. We believe our stock has been undervalued, even today, trading below the net asset value of our proved oil and natural gas reserves and at levels that completely ignore the significant incremental value of our potential CO_2 EOR reserves. We have spent over $940 million through the first quarter of 2014 to repurchase approximately 15% of the shares we had outstanding when we initiated the program in 2011. We've repurchased

A Premier Growth & Income Company

PROVEN & REPEATABLE PROCESS

CO_2 EOR is one of the most efficient tertiary oil recovery methods, delivering almost as much production as each of primary and secondary recovery. To date, Denbury has produced over 100 million barrels (gross) of oil from CO_2 EOR.



STRATEGIC & COMPETITIVE ADVANTAGE

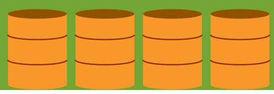
The acquisition and construction of strategic assets has yielded a competitive advantage: large amounts of naturally occurring and man-made CO_2 supply, over 1,100 miles of CO_2 pipelines and a large inventory of oil fields.

LARGE PORTFOLIO OF LOWER RISK GROWTH PROJECTS

Our long-term growth strategy is focused on our CO_2 tertiary recovery operations, made possible by strategic acquisitions & infrastructure developments. We have a substantial asset base with excellent visibility on long-term production growth.

UNIQUE PRODUCTION & CASH FLOW PROFILE

CO_2 EOR is a proven method to extract significant additional amounts of oil from mature oil fields. The unique production profile of CO_2 EOR projects allows for the generation of substantial amounts of free cash flow after the up-front investments are made in CO_2 supply, pipelines, and facilities to initiate them.



> **"WE** are committed to creating value for our shareholders through a combination of production and proved reserve growth, dividends and share repurchases."

between 3.5% and 4.2% of shares outstanding every year starting in 2011 and have repurchased over 3% thus far in 2014, all while maintaining a solid capital structure. The repurchases have improved our per-share metrics and have been completed at attractive prices that we believe make them very accretive for our shareholders. Our repurchase program remains in place with approximately $220 million still authorized as of the date of this letter. We intend to be opportunistic with this program.

In summary, it has been another eventful and productive year at Denbury. We remain focused on increasing shareholder value by optimizing the development of our attractive asset base. We are aware that we have had unfavorable operating and capital cost trends in 2013 and recent years, and as a result are implementing several internal initiatives that we expect will result in meaningful cost reductions in the future. We believe that we can make significant improvements in our cost structure and reverse the recent negative trends. We have excellent visibility on long-term oil production growth in our two core regions, our solid balance sheet provides us tremendous financial flexibility, and our workforce of highly technical, dedicated, and motivated employees is focused on executing our unique strategy.

We strongly believe in our strategy and its long-term economic benefits and are committed to creating value for our shareholders through a combination of production and proved reserve growth, dividends and share repurchases. We look forward to executing our value-driven strategy in 2014 and beyond.

Sincerely,

Phil Rykhoek
President and Chief Executive Officer

March 28, 2014

Board of Directors

Wieland F. Wettstein
Chairman of the Board
President
Finex Financial Corporation, Ltd.
Calgary, Alberta

Michael L. Beatty
Chairman and Chief Executive Officer
Beatty & Wozniak, P.C.
Denver, Colorado

Michael B. Decker
Partner
Wingate Partners
Dallas, Texas

John P. Dielwart
Vice-Chairman
ARC Financial Corp.
Calgary, Alberta

Ronald G. Greene
Principal
Tortuga Investment Corp.
Calgary, Alberta

Gregory L. McMichael
Independent Consultant
Denver, Colorado

Kevin O. Meyers
Independent Consultant
Anchorage, Alaska

Phil Rykhoek
Director, President and Chief Executive Officer
Denbury Resources Inc.
Plano, Texas

Randy Stein
Independent Consultant
Denver, Colorado

Laura A. Sugg
Independent Consultant
Houston, Texas

Our corporate governance guidelines, as well as the charters for our nominating/corporate governance committee; compensation committee; audit committee; and reserves and health, safety and environmental committee can be found on the Company website at www.denbury.com. The website also contains other corporate governance information such as our code of ethics for our directors, officers and employees; our hotline number to report any abnormalities; and other data.

You may contact our board members by addressing a letter to Denbury Resources Inc., Attn: Corporate Secretary, or by email to secretary@denbury.com.

Officers

Phil Rykhoek
Director, President and Chief Executive Officer

Mark C. Allen
Senior Vice President, Chief Financial Officer, Treasurer and Assistant Secretary

K. Craig McPherson
Senior Vice President and Chief Operating Officer

Charlie Gibson
Senior Vice President — Planning, Technology and CO_2 Supply

James S. Matthews
Vice President, General Counsel and Secretary

Dan E. Cole
Vice President — Marketing, Business Development and Government Relations

Matt Elmer
Vice President — West Region

John Filiatrault
Vice President — CO_2 Supply and Pipeline

Jeff Marcel
Vice President — Drilling

Steve McLaurin
Vice President and Chief Information Officer

Alan Rhoades
Vice President and Chief Accounting Officer

Barry Schneider
Vice President — North Region

Whitney Shelley
Vice President and Chief Human Resources Officer

Phil Webb
Vice President — East Region

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

2013 FORM 10-K

(Mark One)

✓ Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2013
OR
___ Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from ________________ to ________________

Commission file number 1-12935

DENBURY RESOURCES INC.

(Exact name of Registrant as specified in its charter)

Delaware	20-0467835
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
5320 Legacy Drive, Plano, TX	75024
(Address of principal executive offices)	*(Zip Code)*

Registrant's telephone number, including area code: (972) 673-2000

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

Title of Each Class:	Name of Each Exchange on Which Registered:
Common Stock $.001 Par Value	New York Stock Exchange

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

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

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a small reporting company. See definition of "large accelerated filer", "accelerated filer", and "small reporting company" in Rule 12-b2 of the Exchange Act.
Large accelerated filer ✓ Accelerated filer ___ Non-accelerated filer ___ Smaller reporting company ___

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

The aggregate market value of the registrant's common stock held by non-affiliates, based on the closing price of the registrant's common stock as of the last business day of the registrant's most recently completed second fiscal quarter was $5,625,842,252.

The number of shares outstanding of the registrant's Common Stock as of January 31, 2014, was 355,982,927.

DOCUMENTS INCORPORATED BY REFERENCE

Document:	Incorporated as to:
1. Notice and Proxy Statement for the Annual Meeting of Shareholders to be held May 20, 2014.	*1. Part III, Items 10, 11, 12, 13, 14*

Table of Contents

Glossary and Selected Abbreviations

Bbl	One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.
Bbls/d	Barrels of oil or other liquid hydrocarbons produced per day.
Bcf	One billion cubic feet of natural gas, CO_2 or helium.
BOE	One barrel of oil equivalent, using the ratio of one barrel of crude oil, condensate or natural gas liquids to 6 Mcf of natural gas.
BOE/d	BOEs produced per day.
Btu	British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit (°F).
CO_2	Carbon dioxide.
EOR	Enhanced oil recovery.
Finding and development costs	The average cost per BOE to find and develop proved reserves during a given period. It is calculated by dividing (a) costs, which include the sum of (i) the total acquisition, exploration and development costs incurred during the period plus (ii) future development and abandonment costs related to the specified property or group of properties, by (b) the sum of (i) the change in total proved reserves during the period plus (ii) total production during that period.
GAAP	Accounting principles generally accepted in the United States of America.
MBbls	One thousand barrels of crude oil or other liquid hydrocarbons.
MBOE	One thousand BOEs.
Mbtu	One thousand Btus.
Mcf	One thousand cubic feet of natural gas, CO_2 or helium at a temperature base of 60 degrees Fahrenheit (°F) and at the legal pressure base (14.65 to 15.025 pounds per square inch absolute) of the state or area in which the reserves are located or sales are made.
Mcf/d	One thousand cubic feet of natural gas, CO_2 or helium produced per day.
MMBbls	One million barrels of crude oil or other liquid hydrocarbons.
MMBOE	One million BOEs.
MMBtu	One million Btus.
MMcf	One million cubic feet of natural gas, CO_2 or helium.
MMcf/d	One million cubic feet of natural gas, CO_2 or helium per day.
Noncash fair value adjustments on commodity derivatives	The net change during the period in the fair market value of commodity derivative positions. up only a portion of "Derivatives expense (income)" in the Consolidated Statements of Operations, which also includes the impact of cash settlements on commodity derivatives during the period. Its use is further discussed in *Management's Discussion and Analysis of Financial Condition – Results of Operations – Operating Results Table.*
NYMEX	The New York Mercantile Exchange. In the context of our oil and natural gas sales, NYMEX pricing represents the West Texas Intermediate benchmark price for crude oil and Henry Hub benchmark price for natural gas.
Probable Reserves*	Reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.
Proved Developed Reserves*	Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved Reserves*	Reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.
Proved Undeveloped Reserves*	Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells, in each case where a relatively major expenditure is required.
PV-10 Value	The estimated future gross revenue to be generated from the production of proved reserves, net of estimated future production, development and abandonment costs, and before income taxes, discounted to a present value using an annual discount rate of 10%. PV-10 Values were prepared using average hydrocarbon prices equal to the unweighted arithmetic average of hydrocarbon prices on the first day of each month within the 12-month period preceding the reporting date. PV-10 Value is a non-GAAP measure and its use is further discussed in footnote 4 to the table included in Item 1, *Estimated Net Quantities of Proved Oil and Natural Gas Reserves and Present Value of Estimated Future Net Revenues – Oil and Natural Gas Reserve Estimates.*
Tcf	One trillion cubic feet of natural gas, CO_2 or helium.
Tertiary Recovery	A term used to represent techniques for extracting incremental oil out of existing oil fields (as opposed to primary and secondary recovery or "non-tertiary" recovery). In the context of our oil and natural gas production, tertiary recovery is also referred to as EOR.

* This definition is an abbreviated version of the complete definition set forth in Rule 4-10(a) of Regulation S-X. For the complete definition see: http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&rgn=div5&view=text&node=17:2.0.1.1.8&idno=17.

Item 1. Business and Properties

GENERAL

Denbury Resources Inc., a Delaware corporation, is a growing, dividend-paying, domestic oil and natural gas company with 468.3 MMBOE of estimated proved oil and natural gas reserves as of December 31, 2013, of which 83% is oil. Our primary focus is on enhanced oil recovery utilizing CO_2, and our operations are focused in two key operating areas: the Gulf Coast and Rocky Mountain regions. Our goal is to increase the value of acquired properties through a combination of exploitation, drilling and proven engineering extraction practices, with the most significant emphasis relating to tertiary recovery operations.

As part of our corporate strategy, we believe in the following fundamental principles:

- focus in specific regions where we either have, or believe we can create, a competitive advantage as a result of our ownership or use of CO_2 reserves, oil fields and CO_2 infrastructure;
- acquire properties where we believe additional value can be created through tertiary recovery operations and a combination of other exploitation, development, exploration and marketing techniques;
- acquire properties that give us a majority working interest and operational control or where we believe we can ultimately obtain it;
- maximize the value and cash flow generated from our operations by increasing production and reserves while controlling costs;
- optimize the timing and allocation of capital among our investment opportunities to maximize the rates of return on our investments;
- return a portion of the cash flow generated from our operations to shareholders through regular quarterly dividend payments, and repurchases of our common stock made from time to time; and
- maintain a highly competitive team of experienced and incentivized personnel.

Denbury has been publicly traded on the New York Stock Exchange since 1997. Our corporate headquarters is located at 5320 Legacy Drive, Plano, Texas 75024, and our phone number is 972-673-2000. At December 31, 2013, we had 1,501 employees, 807 of whom were employed in field operations or at our field offices. We make our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports, filed or furnished pursuant to section 13(a) or 15(d) of the Securities Exchange Act of 1934, available free of charge on or through our Internet website, www.denbury.com, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. The SEC also maintains a website, www.sec.gov, which contains reports, proxy and information statements and other information filed by Denbury. Throughout this Annual Report on Form 10-K (“Form 10-K”) we use the terms “Denbury,” “Company,” “we,” “our,” and “us” to refer to Denbury Resources Inc. and, as the context may require, its subsidiaries.

2012 AND 2013 MAJOR PROPERTY EXCHANGES AND ACQUISITIONS

We set the stage for our 2013 business developments with two major transactions. In December 2012, we closed a sale and exchange transaction with Exxon Mobil Corporation and its wholly-owned subsidiary XTO Energy Inc, (collectively, “ExxonMobil”) under which we sold to ExxonMobil our Bakken area assets in North Dakota and Montana in exchange for (1) $1.3 billion in cash, (2) operating interests in Hartzog Draw and Webster fields in Wyoming and Texas, respectively, and (3) an overriding royalty interest equivalent to an approximate one-third ownership interest in ExxonMobil’s CO_2 reserves in LaBarge Field in Wyoming (the “Bakken Exchange Transaction”). We utilized cash received in this exchange to fund our March 2013 acquisition of producing assets in the Cedar Creek Anticline (“CCA”) in Montana and North Dakota from ConocoPhillips Company (“ConocoPhillips”) for $1.05 billion in cash, before closing adjustments.

Taken together, these two asset transactions nearly replaced the production of the sold assets with production from the acquired assets, exchanged proved reserves with a high proved undeveloped component in the Bakken for reserves that were nearly all proved developed in CCA, increased our Rocky Mountain CO_2 reserves by 1.3 Tcf and our CO_2 deliverability by up to 115 MMcf/d, and positioned us to provide dividends to our stockholders as discussed below.

2013 BUSINESS DEVELOPMENTS

In the fourth quarter of 2013, following a comprehensive review of our long-term plans, we announced our intention to expand our shareholder value proposition to include both growth and income. The expansion includes the initiation of regular quarterly cash dividend payments to our shareholders starting with $0.0625 per share (a rate of $0.25 per share on an annualized basis). The first quarterly cash dividend of $0.0625 was declared on January 28, 2014, payable March 25, 2014, to shareholders of record as of the close of business on February 25, 2014. Based on our current financial projections and commodity price outlook, we expect to grow our annual dividend rate to between $0.50 per share and $0.60 per share in 2015 and at a sustainable rate thereafter. All dividends are discretionary and subject to declaration by Denbury's Board of Directors.

To expand our free cash flow, we adjusted certain of our development plans and timelines for various capital projects, principally in the Rocky Mountain region, in order to reduce our spending on certain major infrastructure projects over the next few years. These adjustments allowed us to accelerate our plan of providing a return to our shareholders through a growing cash dividend, while still growing our reserves and production. Our focused strategy, significant inventory of development projects and proven track record of value creation give us confidence that we can deliver a long-term cash flow profile that is unique among independent oil companies and successfully execute on our value-driven growth and income strategy in 2014 and beyond.

2013 business developments also include the following:

- Increased our average tertiary oil production to 38,477 Bbls/d in 2013, a 9% increase from average tertiary production in 2012, primarily due to continued field development and expansion of facilities in our existing CO_2 floods at Delhi, Hastings, Heidelberg and Oyster Bayou fields.
- Added total proved reserves of 84.6 MMBOE including estimated proved tertiary reserves of 34.0 MMBbls at Bell Creek Field, proved non-tertiary reserves of 42.2 MMBOE (added through our 2013 acquisition of interests at CCA) and 8.4 MMBOE of other additions or revisions.
- Added estimated proved CO_2 reserves of 350 Bcf as a result of successful drilling in the Jackson Dome area, our primary source of CO_2 for the Gulf Coast region.
- Continued our share repurchase program, under which we repurchased a total of 16.5 million shares of Denbury common stock for $277.8 million during 2013. We have purchased a total of 59.4 million shares of Denbury common stock (approximately 14.8% of our outstanding shares of common stock at September 30, 2011) for $931.2 million, or an average of $15.68 per share, since commencement of the share repurchase program in October 2011 and continuing through February 20, 2014. As of February 20, 2014, we had $230.7 million remaining for future purchases under our authorized share repurchase program.
- Commenced injection of CO_2 into our first two tertiary floods in the Rocky Mountain region, Bell Creek Field in Montana and Grieve Field in Wyoming during the first half of 2013, and commenced our first tertiary oil production in that region from Bell Creek Field during the third quarter of 2013.
- Placed our Riley Ridge gas processing facility into service in the fourth quarter of 2013.
- Commenced a horizontal oil drilling program at Hartzog Draw Field in the Powder River Basin of Wyoming targeting the Shannon formation. We expect the horizontal wells to increase the field's non-tertiary oil production and reserves and to eventually be utilized in our planned future CO_2 flood of the field.
- Issued $1.2 billion of 4⅝% Senior Subordinated Notes due 2023 in February 2013. The net proceeds of approximately $1.18 billion were used to repurchase or redeem our 9½% Senior Subordinated Notes due 2016 and our 9¾% Senior Subordinated Notes due 2016, and to pay down a portion of outstanding borrowings on our bank credit facility.
- Closed our acquisition of producing assets in the CCA in Montana and North Dakota in March 2013 from a wholly-owned subsidiary of ConocoPhillips for $1.05 billion in cash, before closing adjustments. The assets purchased include both additional interests in certain of our existing operated fields in CCA, as well as operating interests in other CCA fields.

OIL AND NATURAL GAS OPERATIONS

Summary. Our oil and natural gas properties are concentrated in the Gulf Coast and Rocky Mountain regions of the United States. Currently our properties with proved and producing reserves in the Gulf Coast region are situated in Mississippi, Texas, Louisiana and Alabama, and in the Rocky Mountain region in Montana, North Dakota and Wyoming. Our primary focus is using CO_2 in EOR, and we expect the development plan for our current portfolio of CO_2 EOR projects will allow us to grow our oil production for the remainder of the decade.

We have been conducting and expanding EOR operations on our assets in the Gulf Coast region since 1999, and as a result, we currently have many more CO_2 EOR projects in this region than in the Rocky Mountain region. In the Gulf Coast region, we own what is, to our knowledge, its only significant naturally occurring source of CO_2. These large volumes of naturally occurring CO_2 have allowed us to significantly grow our production in that region. In addition to the sources of CO_2 we currently own, in 2013 we began to purchase and use anthropogenic (man-made) CO_2 in our tertiary operations. We believe these man-made sources of CO_2 will help us recover additional oil from mature oil fields while also providing an economical way to reduce atmospheric CO_2 emissions through the concurrent underground storage of CO_2 from our oil-producing EOR operations, and expect the amount of anthropogenic CO_2 we use in such operations to grow in the future.

Through December 31, 2013, we have invested a total of $3.5 billion in our tertiary fields in the Gulf Coast region (including allocated acquisition costs and amounts assigned to goodwill), have recovered all of these costs, and have generated $1.5 billion of excess net cash flow (revenue less operating expenses and capital expenditures, excluding capital expenditures related to pipelines and CO_2 source fields). Of this total invested amount, approximately $206.7 million (6%) has been spent on fields that did not yet have any appreciable proved reserves at December 31, 2013. The proved oil reserves in our Gulf Coast tertiary oil fields have a year-end 2013 PV-10 Value of $6.1 billion. Including the Green Pipeline, which currently serves our Hastings and Oyster Bayou fields, we have invested a total of $2.1 billion in CO_2-producing assets and pipelines in the Gulf Coast region.

We began operations in the Rocky Mountain region in 2010 as part of our merger with Encore Acquisition Company ("Encore"). In late 2012, we completed construction of the first section of the 20-inch Greencore Pipeline, our first CO_2 pipeline in the Rocky Mountain region, and received our first CO_2 deliveries from the Lost Cabin gas plant in central Wyoming during the first quarter of 2013. We also began injecting CO_2 into Grieve Field in Wyoming early in 2013 and currently expect initial tertiary oil production from Grieve Field in 2015. We started injections at our Bell Creek Field in Montana during the second quarter of 2013, with tertiary oil production from this field commencing in the third quarter of 2013. In addition to our current tertiary floods in the Rocky Mountain region, we currently have long-term plans to flood Hartzog Draw Field and CCA after we perform additional non-tertiary development of these fields. CCA is a geological structure over 126 miles in length consisting of 14 different operating areas. Our Riley Ridge Field acquisitions in 2010 and 2011 and acquisition of an interest in CO_2 reserves from ExxonMobil in 2012 are expected to provide us the CO_2 necessary for our current inventory of CO_2 EOR projects in the Rocky Mountain region.

Field Summary Table. The following table provides a summary by field and region of selected proved oil and natural gas reserve information, including total proved reserve quantities and the associated PV-10 Value of those reserves as of December 31, 2013, and average daily production and net revenue interest ("NRI") for 2013. The reserve estimates for all years presented were prepared by DeGolyer and MacNaughton, independent petroleum engineers located in Dallas, Texas. We serve as operator of virtually all of our significant properties, in which we also own most of the interests, although typically less than a 100% working interest, and a lesser NRI due to royalties and other burdens. For additional oil and natural gas reserves information, see *Estimated Net Quantities of Proved Oil and Natural Gas Reserves and Present Value of Estimated Future Net Revenues* below.

	Proved Reserves as of December 31, 2013[1]					2013 Average Daily Production		
	Oil (MBbls)	Natural Gas (MMcf)	MBOEs	% of Company Total MBOEs	PV-10 Value[2] (000's)	Oil (Bbls/d)	Natural Gas (Mcf/d)	Average 2013 NRI
Tertiary oil properties								
Gulf Coast region								
Mature properties:								
Brookhaven	10,069	—	10,069	2.2%	$ 363,644	2,223	—	81.2%
Eucutta	8,074	—	8,074	1.7%	267,583	2,514	—	83.6%
Mallalieu	5,700	—	5,700	1.2%	220,759	2,050	—	78.0%
Other mature properties[3]	24,756	—	24,756	5.3%	747,767	7,016	—	73.8%
Total mature properties	48,599	—	48,599	10.4%	1,599,753	13,803	—	77.2%
Delhi	26,449	17,856	29,425	6.3%	747,334	5,149	—	76.3%
Hastings	43,424	—	43,424	9.3%	1,106,246	3,984	—	81.7%
Heidelberg	34,496	—	34,496	7.3%	1,097,130	4,466	—	81.4%
Oyster Bayou	15,132	—	15,132	3.2%	550,025	2,968	—	87.0%
Tinsley	25,344	—	25,344	5.4%	1,018,938	8,051	—	81.1%
Total Gulf Coast region	193,444	17,856	196,420	41.9%	6,119,426	38,421	—	79.5%
Rocky Mountain region								
Bell Creek	34,015	—	34,015	7.3%	739,019	56	—	84.8%
Total Rocky Mountain region	34,015	—	34,015	7.3%	739,019	56	—	84.8%
Total tertiary properties	227,459	17,856	230,435	49.2%	6,858,445	38,477	—	79.5%
Non-tertiary oil and gas properties								
Gulf Coast region								
Mississippi	4,514	33,290	10,062	2.1%	195,138	1,234	8,766	26.1%
Texas	30,988	18,105	34,006	7.3%	814,609	5,549	5,946	79.1%
Other	6,609	1,386	6,840	1.5%	147,406	983	686	26.4%
Total Gulf Coast region	42,111	52,781	50,908	10.9%	1,157,153	7,766	15,398	48.7%
Rocky Mountain region								
Cedar Creek Anticline[4]	105,396	6,043	106,403	22.7%	2,335,966	16,406	997	79.6%
Riley Ridge	—	399,373	66,562	14.2%	27,810	—	64	61.4%
Other	11,693	13,901	14,010	3.0%	254,409	3,637	7,283	29.4%
Total Rocky Mountain region	117,089	419,317	186,975	39.9%	2,618,185	20,043	8,344	60.5%
Total non-tertiary properties	159,200	472,098	237,883	50.8%	3,775,338	27,809	23,742	56.2%
Company Total	386,659	489,954	468,318	100%	$10,633,783	66,286	23,742	68.2%

(1) The reserves were prepared in accordance with Financial Accounting Standards Board Codification ("FASC") Topic 932, *Extractive Industries – Oil and Gas,* using the arithmetic average of the first-day-of-the-month NYMEX commodity price for each month during 2013. These prices were $96.94 per Bbl for crude oil and $3.67 per MMBtu for natural gas, both of which were adjusted for market differentials by field.

(2) PV-10 Value is a non-GAAP measure and is different from the Standardized Measure of Discounted Future Net Cash Flows ("Standardized Measure") in that PV-10 Value is a pre-tax number and the Standardized Measure is an after-tax number. The Standardized Measure was $7.1 billion at December 31, 2013. A comparison of PV-10 Value to the Standardized Measure is included in the reserves table in *Estimated Net Quantities of Proved Oil and Natural Gas Reserves and Present Value of Estimated Future Net Revenues* below. The information used to calculate PV-10 Value is derived directly from data determined in accordance with FASC Topic 932. See the definition of PV-10 Value in the *Glossary and Selected Abbreviations.*

(3) Other mature properties include Cranfield, Little Creek, Lockhart Crossing, Martinville, McComb and Soso fields in Mississippi and Lockhart Crossing in Louisiana.

(4) The Cedar Creek Anticline consists of a series of 14 different operating areas.

Enhanced Oil Recovery Overview. CO_2 used in EOR is one of the most efficient tertiary recovery mechanisms for producing crude oil. When injected at pressure into underground, oil-bearing rock formations, CO_2 acts somewhat like a solvent as it travels through the reservoir rock, mixing with and modifying the characteristics of the oil so it can be produced and sold. CO_2 tertiary floods are unique in that they require large volumes of CO_2. The terms "tertiary flood," "CO_2 flood" and "CO_2 EOR" are used interchangeably throughout this document.

While enhanced oil recovery projects utilizing CO_2 have been successfully performed by numerous oil and gas companies in a wide range of oil-bearing reservoirs in different oil-producing basins, we apply what we have learned and developed over the years to fields to improve and increase sweep efficiency within the CO_2 EOR projects we operate, which include (1) well evaluation and monitoring methods, (2) monitoring the flood and striving to direct the CO_2 to all economically recoverable portions of the oil-bearing reservoirs, (3) new completion techniques, (4) varied operating equipment and operating methods, and (5) application of intense reservoir management and production techniques. We began our CO_2 operations in August 1999, when we acquired Little Creek Field, followed by our acquisition of Jackson Dome CO_2 reserves and the NEJD pipeline in 2001. Based upon our success at Little Creek and the ownership of the CO_2 reserves, we began to transition our capital spending and acquisition efforts to focus a greater percentage on CO_2 EOR and, over time, transformed our strategy to focus primarily, and now almost exclusively, on owning and operating oil fields that are well suited for CO_2 EOR projects, although prior to tertiary flooding, we strive to maximize the currently sizeable primary and secondary production from our prospective tertiary fields and from fields in which tertiary floods have commenced but still contain significant non-tertiary production. With the sale of our Bakken area assets in 2012, our asset base today almost entirely consists of, or otherwise relates to, oil fields that we are currently flooding with CO_2 or plan to flood with CO_2 in the future, or assets that produce CO_2. We believe our investments, experience and acquired knowledge give us a strategic and competitive advantage in the areas in which we operate.

Our tertiary operations have grown so that (1) 49% of our proved reserves at December 31, 2013 are proved tertiary oil reserves; (2) 55% of our 2013 production was related to tertiary oil operations (on a BOE basis); and (3) 77% of our 2013 capital expenditures (excluding acquisitions) were related to our tertiary oil operations. At year-end 2013, the proved oil reserves in our tertiary recovery oil fields had an estimated PV-10 Value of approximately $6.9 billion, or 64% of our total PV-10 Value. In addition, there are significant probable and possible reserves at several other fields for which tertiary operations are underway or planned. Although the up-front cost of tertiary production infrastructure and time to construct these pipelines and production facilities is greater than in primary oil recovery, we believe tertiary recovery has several favorable, offsetting and unique attributes, including (1) a lower exploration risk, as we are operating oil fields that have significant historical production and reservoir and geological data, (2) a reasonable rate of return at relatively low oil prices (we currently estimate our economic break-even point before corporate-related overhead, based on currently estimated expenses, occurs at oil prices in the low-to-mid $40-per-barrel range, depending on the specific field and area), (3) limited competition for this recovery method in our geographic regions, (4) our EOR operations are generally less disruptive to new habitats in comparison to other oil and natural gas development because we further develop existing (as opposed to new) oil fields, and (5) through our oil-producing EOR operations, we concurrently store anthropogenic CO_2 in the same underground formations that had previously trapped and stored oil and natural gas.

Tertiary Oil Properties

Gulf Coast Region

CO_2 Sources and Pipelines

Jackson Dome. Our primary Gulf Coast CO_2 source, Jackson Dome, located near Jackson, Mississippi, was discovered during the 1970s by oil and gas companies that were exploring for hydrocarbons. This large and relatively pure source of naturally occurring CO_2 (98% CO_2) is, to our knowledge, the only significant underground deposit of CO_2 in the United States east of the Mississippi River, and we believe that it, together with the related CO_2 pipeline infrastructure, provides us a significant strategic advantage in the acquisition of other properties in Mississippi, Louisiana and southeastern Texas that are well suited for CO_2 EOR.

We acquired Jackson Dome in February 2001 in a purchase that also gave us ownership and control of the NEJD CO_2 pipeline and provided us with a reliable supply of CO_2 at a reasonable and predictable cost for our Gulf Coast CO_2 tertiary recovery operations. Since February 2001, we have acquired and drilled numerous CO_2-producing wells, significantly increasing our estimated proved Gulf Coast CO_2 reserves from approximately 800 Bcf at the time of acquisition to approximately 6.1 Tcf as of December 31, 2013. The CO_2 reserve estimates are based on a gross working interest of the CO_2 reserves, of which our net revenue interest is approximately 4.8 Tcf, and is included in the evaluation of proved CO_2 reserves prepared by our outside reserves engineer, DeGolyer and MacNaughton. In discussing our available CO_2 reserves, we make reference to the gross amount of proved and probable reserves, as this is the amount that is available both for our own tertiary recovery programs and for industrial users who are customers of Denbury and others, as we are responsible for distributing the entire CO_2 production stream.

In addition to the proved reserves, we estimate that we have 2.5 Tcf of probable CO_2 reserves at Jackson Dome. The majority of our probable reserves at Jackson Dome are located in structures that have been drilled and tested in the area but are not currently capable of producing or are not considered proved reserves because (1) the original well is plugged; (2) they are located in fault blocks that are immediately adjacent to fault blocks with proved reserves; (3) they are in undrilled structures where we have sufficient subsurface data, and seismic and geophysical attributes that provide a high degree of certainty that CO_2 is present; or (4) they are reserves associated with increasing the ultimate recovery factor from our existing reservoirs with proved reserves. Our historically high drilling success rate, coupled with our seismic data across the undrilled structures, provide us with a reasonably high degree of certainty that additional proved CO_2 reserves will be discovered and developed.

Although our current proved CO_2 reserves are quite large, in order to continue our tertiary development of oil fields in the Gulf Coast region, incremental deliverability of CO_2 is required. In order to obtain additional CO_2 deliverability, we have conducted several 3D seismic surveys in the Jackson Dome area over the past several years, and anticipate drilling one development well in 2014 that is intended to increase the area's productive capacity.

In addition to our drilling at Jackson Dome, we continue to expand our processing and dehydration capacities, and we continue to install pipelines and/or pumping stations necessary to transport the CO_2 through our controlled pipeline network. We expect our current proved reserves of CO_2, coupled with a risked drilling program at Jackson Dome and expected anthropogenic sources, to provide sufficient quantities of CO_2 for us to develop our proved and probable EOR reserves in the Gulf Coast region. Additionally, in the future, we believe that once a CO_2 flood in a field reaches its productive economic limit, we could recycle a portion of any CO_2 that remains in that reservoir and utilize it for oil production in another tertiary flood.

In the Gulf Coast region, we also currently sell CO_2 to third-party industrial users under contracts of various terms and currently have three CO_2 volumetric production payment contracts. Approximately 91% of our average daily CO_2 produced or acquired from anthropogenic sources in 2013, 2012 and 2011 was used in our tertiary recovery operations, with the balance delivered to third-party industrial users. During 2013, we used an average of 913 MMcf/d of CO_2 (including CO_2 from anthropogenic sources) for our tertiary activities.

Gulf Coast Anthropogenic CO_2 Sources. In addition to our natural source of CO_2, we are currently party to four long-term contracts to purchase man-made CO_2 from four plants. We currently purchase anthropogenic CO_2 from an industrial facility in Port Arthur, Texas and from a plant in Geismar, Louisiana, and we anticipate taking deliveries in late 2014 from Mississippi Power's Kemper County Energy Facility. We estimate these three sources will supply, in the aggregate, approximately 185 MMcf/d of CO_2 to our EOR operations, although under certain circumstances they could provide higher or lower volumes. If the fourth plant for which we have a long-term CO_2 purchase contract were also to be built (targeted for the 2018 time frame), we currently estimate this source in Lake Charles, Louisiana could potentially add another 200 MMcf/d of CO_2 volumes to our anthropogenic sources. Construction of this remaining plant is considered probable, although such construction is contingent on the satisfactory resolution of various matters, including financing. Additionally, we are in ongoing discussions with other parties who have plans to construct plants near the Green Pipeline.

In addition to the potential CO_2 sources discussed above, we continue to have ongoing discussions with owners of existing plants of various types that emit CO_2 that we may be able to purchase and/or transport. In order to capture such volumes, we (or the plant owner) would need to install additional equipment, which includes, at a minimum, compression and dehydration facilities. Most of these existing plants emit relatively small volumes of CO_2, generally less than our contracted sources, but such volumes may still be attractive if the source is located near CO_2 pipelines. The capture of CO_2 could also be influenced by potential federal legislation, which could impose economic penalties for atmospheric CO_2 emissions. We believe that we are a likely purchaser of CO_2 captured in our areas of operation because of the scale of our tertiary operations and our CO_2 pipeline infrastructure.

Gulf Coast CO_2 Pipelines. We acquired the 183-mile NEJD CO_2 pipeline that runs from Jackson Dome to near Donaldsonville, Louisiana, as part of the 2001 acquisition of our Jackson Dome source. Since 2001 we have acquired or constructed nearly 750 miles of CO_2 pipelines, which give us the ability to deliver CO_2 throughout the Gulf Coast region. As of December 31, 2013, we have access to over 940 miles of CO_2 pipelines in the Gulf Coast region. In addition to the NEJD CO_2 pipeline, the major pipelines are the Free State Pipeline (90 miles), the Delta Pipeline (110 miles), the Green Pipeline Texas (120 miles), and the Green Pipeline Louisiana (200 miles).

Completion of the Green Pipeline allowed for the first CO_2 injection into Hastings Field, located near Houston, Texas, in 2010, and gives us the ability to deliver CO_2 to oil fields all along the Gulf Coast from Baton Rouge, Louisiana, to Alvin, Texas. At the present time, most of the CO_2 flowing in the Green Pipeline is delivered from the Jackson Dome area, but we began receiving anthropogenic CO_2 from an industrial facility in Port Arthur, Texas in 2012, and are currently transporting a third party's CO_2 for a fee to the sales point at Hastings Field. We expect the volume of CO_2 transported through the Green Pipeline to increase in future years as we develop our inventory of CO_2 EOR projects in the Houston area.

Tertiary Properties with Tertiary Production and Proved Tertiary Reserves at December 31, 2013

Mature properties. Mature properties include our longest-producing properties which are generally located along our NEJD CO_2 pipeline in southwest Mississippi and Louisiana and our Free State pipeline in east Mississippi. This group of properties includes our initial CO_2 field, Little Creek, as well as several other fields (Brookhaven, Cranfield, Eucutta, Lockhart Crossing, Mallalieu, Martinville, McComb and Soso fields). These fields accounted for 36% of our total 2013 CO_2 EOR production and approximately 21% of our year-end proved tertiary reserves. These fields have been producing for some time, and their production is generally declining. Many of these fields contain multiple reservoirs that are amenable to CO_2 EOR. In 2014, we plan to invest approximately $115 million to further develop our mature tertiary properties.

In order to improve the oil recovery of our more mature CO_2 EOR projects, we have experimented with various techniques such as cement squeezes (injection and producing wells), chemical squeezes, perforation design, mechanical isolation assemblies and operating pressure controls. We have also utilized water-alternating-gas injections, where water is substituted for the CO_2 for a given volume and then CO_2 is injected behind the water. Each one of these processes has had some success, and we plan to continue to utilize them in the future where appropriate.

From the time we originally acquired these properties through December 31, 2013, we have recovered all our costs relating to our mature properties, and the excess net cash flow (revenue less operating expenses and capital expenditures, including the acquisition costs) from the mature properties through that date was $1.9 billion. As of December 31, 2013, the estimated PV-10 Value of our mature properties was $1.6 billion.

Delhi Field. Delhi Field is located east of Monroe, Louisiana. During May 2006, we purchased Delhi for $50 million, plus an approximate 25% reversionary interest to the seller after we receive $200 million in "total net cash flow," as defined. We began well and facility development in 2008 and began delivering CO_2 to the field in the fourth quarter of 2009 via the Delta Pipeline, which runs from Tinsley Field to Delhi Field. First tertiary production occurred at Delhi Field in the first quarter of 2010. Production from Delhi in the fourth quarter of 2013 averaged 4,793 Bbls/d, down from 5,237 Bbls/d in the fourth quarter of 2012. This decline in production is primarily related to our efforts to remediate a release of well fluids within an area of Delhi Field in the second quarter of 2013, consisting of a mixture of carbon dioxide, saltwater, natural gas and oil. During 2013, we recorded $114.0 million of lease operating expenses in our Consolidated Statement of Operations related to this incident. Costs incurred as a result of the release, together with lower production levels, are currently expected to delay the effective date of the reversionary interest into 2014, the specific timing of which is dependent upon, among other things, the amount and timing of any potential insurance proceeds received and their application to the calculation of "total net cash flow," as well as oil prices, production, and production costs. We currently estimate that the reversionary date could occur as late as the fourth quarter of 2014. See Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – Overview – Delhi Field Release* and Note 11, *Commitments and Contingencies* to the Consolidated Financial Statements for further discussion of this matter. In 2014, we plan to invest approximately $40 million in this field, primarily to install a natural gas liquids extraction plant, which we anticipate will be operational in 2015.

From inception through December 31, 2013, we had not yet recovered our investment in this field, and the remaining investment to be recovered (revenue less operating expenses and capital expenditures, including acquisition costs) from Delhi Field was $111 million. As of December 31, 2013, the estimated PV-10 Value of Delhi Field was $747.3 million.

Hastings Field. Hastings Field is located south of Houston, Texas. We acquired a majority interest in this field in February 2009 for $247 million. We initiated CO_2 injection in the West Hastings Unit during the fourth quarter of 2010 upon completion of the construction of the Green Pipeline. Due to the large vertical oil column that exists in the field, we are developing the Frio reservoir using dedicated CO_2 injection and producing wells for each of the major sand intervals. We began producing oil from our EOR operations at Hastings Field in the first quarter of 2012, and we booked initial proved tertiary reserves for the West Hastings Unit in 2012. During the fourth quarter of 2013, tertiary production from Hastings Field averaged 4,270 Bbls/d, compared to 3,409 Bbls/d in the fourth quarter of 2012. In 2014, we plan to invest approximately $75 million to continue developing the West Hastings Unit, including the development of additional patterns and expansion of the processing facilities.

From inception through December 31, 2013, we had not yet recovered our investment in this field, and the remaining investment to be recovered (revenue less operating expenses and capital expenditures, including the acquisition cost) from Hastings Field was $336 million. As of December 31, 2013, the estimated PV-10 Value of Hastings Field was $1.1 billion.

Heidelberg Field. Heidelberg Field is located in Mississippi and consists of an East Unit and a West Unit. Construction of the CO_2 facility, connecting pipeline and well work commenced on the West Heidelberg Unit during 2008, with our first CO_2 injections into the Eutaw zone in the fourth quarter of 2008. Our first tertiary oil production occurred in the second quarter of 2009, and during 2010, we added injection patterns and expanded the central processing facility. In 2013, we began flooding the Christmas zone. During the fourth quarter of 2013, tertiary production at Heidelberg Field averaged 5,206 Bbls/d, compared to 3,930 Bbls/d in the fourth quarter of 2012. In 2014, we plan to invest approximately $120 million to continue developing the East and West Heidelberg Units, including an expansion of our development of the Eutaw and Christmas zones and adjustments to our CO_2 floods of existing zones to better direct the CO_2 through the zones and optimize oil recovery from the field.

From inception through December 31, 2013, we had not yet recovered our costs relating to the CO_2 flood at Heidelberg Field, and the remaining investment to be recovered (revenue less operating expenses and capital expenditures, including the acquisition costs) from the field was $10 million. As of December 31, 2013, the estimated PV-10 Value of Heidelberg Field was $1.1 billion.

Oyster Bayou Field. We acquired a majority interest in Oyster Bayou Field in 2007. The field is located in southeast Texas, east of Galveston Bay. We began CO_2 injections into Oyster Bayou in the second quarter of 2010. Oyster Bayou Field is somewhat unique when compared to our other CO_2 EOR projects because the field covers a relatively small area of 3,912 acres. We commenced tertiary production from Oyster Bayou Field in the fourth quarter of 2011 from the Frio A-1 zone and booked initial proved tertiary reserves for the field in 2012. During the fourth quarter of 2013, tertiary production at Oyster Bayou Field averaged 3,869 Bbls/d, compared to 1,826 Bbls/d in the fourth quarter of 2012. In 2014, we plan to invest approximately $50 million to develop the Frio A-2 zone and optimize our Frio A-1 zone development.

From inception through December 31, 2013, we had not yet recovered our investment in this field, and the remaining investment to be recovered (revenue less operating expenses and capital expenditures, including the acquisition costs) from Oyster Bayou Field was $98 million. As of December 31, 2013, the estimated PV-10 Value of Oyster Bayou Field was $550.0 million.

Tinsley Field. We acquired Tinsley Field in 2006. The field is located in Mississippi, was discovered and first developed in the 1930s and is separated into different fault blocks. As is the case with the majority of fields in Mississippi, Tinsley produces from multiple reservoirs. Our CO_2 enhanced oil recovery operations at Tinsley have thus far targeted the Woodruff formation, although there is additional potential in the Perry sandstone and other smaller reservoirs. We commenced tertiary oil production from Tinsley Field in the second quarter of 2008. In 2014, we expect to invest approximately $50 million to continue our development of the North Fault Block and to develop dedicated injection wells in the East Fault Block. We currently expect our development of the Woodruff to be substantially complete by the end of 2014. During the fourth quarter of 2013, the average tertiary oil production was 7,809 Bbls/d, compared to 8,166 Bbls/d in the fourth quarter of 2012.

From inception through December 31, 2013, we have recovered all our costs in this field, and our tertiary operations at Tinsley Field have generated excess net cash flow (revenue less operating expenses and capital expenditures, including the acquisition costs) of $340 million. As of December 31, 2013, the estimated PV-10 Value of Tinsley Field was $1.0 billion.

Future Tertiary Properties with No Tertiary Production or Proved Tertiary Reserves at December 31, 2013

Webster Field. We acquired our interest in Webster Field in the fourth quarter of 2012 as part of the Bakken Exchange Transaction. The field is located in Texas, approximately eight miles northeast of our Hastings Field, which we are currently flooding with CO_2. At December 31, 2013, Webster Field had estimated proved non-tertiary reserves of approximately 3.2 MMBOE, net to our acquired interest. During the fourth quarter of 2013, non-tertiary production at Webster Field averaged 1,036 BOE/d. Webster Field is geologically similar to our Hastings Field, producing oil from the Frio zone at similar depths; as a result, we believe it is well suited for CO_2 EOR. In 2014, we plan to invest approximately $105 million to drill or recomplete injection and production wells and begin water injections to re-pressurize the reservoir. We currently expect to commence CO_2 injections at Webster Field in 2015, with first tertiary production expected late that same year.

Conroe Field. Conroe Field, our largest potential tertiary flood in the Gulf Coast region, is located north of Houston, Texas. We acquired a majority interest in this field in 2009 for $271 million in cash and 11.6 million shares of Denbury common stock, for a total aggregate value of $439 million. Conroe Field had estimated proved non-tertiary reserves of approximately 12.3 MMBOE at December 31, 2013, net to our interest, nearly all of which are proved developed. During the fourth quarter of 2013, production at Conroe Field averaged 2,697 BOE/d, compared to 2,745 BOE/d in the fourth quarter of 2012. Given the size of the Conroe Field (approximately 20,000 acres), the volume of CO_2 that could be injected is quite sizable, and much larger than any field we have developed to date. Therefore, the pace of development will be dictated in part by the amount of available CO_2.

A pipeline must be constructed so that CO_2 can be delivered to Conroe Field. This pipeline, which is planned as an extension of our Green Pipeline, is preliminarily estimated to cover approximately 90 miles at a cost of approximately $220 million. We currently expect to begin construction of this pipeline in 2016 and to commence CO_2 injections at Conroe Field in 2017, with first tertiary production currently expected in 2018. In 2014, we plan to continue work on pipeline route selection, right-of-way acquisition, engineering, and regulatory permits while building our CO_2 EOR development plan for Conroe Field. In 2014, we also plan to invest approximately $30 million on non-tertiary well recompletions and to begin water injections into the area of the field in which we plan to commence CO_2 injections to begin building reservoir pressure.

Thompson Field. We acquired our interest in Thompson Field in June 2012 for $366 million. The field is located in Texas, approximately 18 miles west of our Hastings Field. Thompson Field had estimated proved non-tertiary reserves of approximately 15.4 MMBOE at December 31, 2013, net to our interest, of which approximately 54% are proved developed. During the fourth quarter of 2013, non-tertiary production at Thompson Field averaged 1,331 BOE/d net to our interest, compared to 1,517 BOE/d in the fourth quarter of 2012. Thompson Field is geologically similar to Hastings Field, producing oil from the Frio zone at similar depths and we therefore believe it is well suited for CO_2 EOR. Under the terms of the Thompson Field acquisition agreement, after the initiation of CO_2 injection, the seller will retain approximately a 5% gross revenue interest (less severance taxes) once average monthly oil production exceeds 3,000 Bbls/d. In 2014, we plan to invest approximately $15 million on non-tertiary drilling opportunities and facility upgrades. We currently plan to commence CO_2 injections at Thompson Field in 2018, with first tertiary production expected in 2020.

Rocky Mountain Region

CO_2 Sources and Pipelines

LaBarge Field. We acquired an overriding royalty interest equivalent to an approximate one-third ownership interest in ExxonMobil's CO_2 reserves in LaBarge Field in the fourth quarter of 2012 as part of the Bakken Exchange Transaction. LaBarge Field is located in southwestern Wyoming. The gas composition from LaBarge Field is expected to be approximately 65% CO_2, approximately 18% to 20% methane, less than one percent helium, and the remainder various other gases.

During December 2013, we received approximately 41 MMcf/d from ExxonMobil's Shute Creek gas processing plant at LaBarge Field. Based on current capacity, and subject to availability of CO_2, we currently expect to ultimately receive up to 65 MMcf/d of CO_2 in 2014, rising to approximately 115 MMcf/d of CO_2 by 2021 from such plant. We pay ExxonMobil a fee to process and deliver the CO_2, which we plan to use in our Rocky Mountain region CO_2 floods. As of December 31, 2013, our interest in LaBarge Field consisted of approximately 1.3 Tcf of proved CO_2 reserves.

The Riley Ridge Federal Unit is also located in southwestern Wyoming and produces gas from the same LaBarge Field. In a series of two acquisitions in 2010 and 2011, we acquired 100% of the operating interests in Riley Ridge for $347 million. These purchases included a gas processing facility that was under construction at the purchase dates to separate the helium and natural gas from the gas stream. We placed our gas processing facility at Riley Ridge into service in the fourth quarter of 2013.

As of December 31, 2013, our interest in Riley Ridge and minor surrounding acreage contained net proved reserves of 399 Bcf (67 MMBOE) of natural gas and 2.0 Tcf of CO_2 reserves. The CO_2 reserve estimates are based on the gross working interest of the CO_2 reserves, in which our net revenue interest is approximately 1.6 Tcf. The helium reserves at Riley Ridge are owned primarily by the U.S. government; however, we have the right to produce and sell the helium reserves to a third party on behalf of the government. In exchange for this right, we pay the U.S. government a fee that fluctuates based upon realized sales proceeds. Our helium extraction agreement with the U.S. government has a minimum term extending 20 years from first production and continuing thereafter until either party terminates the contract. Reserve volumes presented herein assume that the term of this helium extraction agreement continues beyond 20 years, given the benefit to both parties to the agreement. As of December 31, 2013, we estimate that Riley Ridge contains proved helium reserves of 13.3 Bcf, which volume estimate is reduced to reflect the related fee we will remit to the U.S. government. In addition, we believe there is significant reserve potential in other acreage surrounding Riley Ridge in which we also own an interest.

The gas processing facility at Riley Ridge will separate for sale the natural gas and helium from the full well stream, and the remaining gases, including CO_2, will be re-injected into the producing formation or a deeper formation until we complete construction of a planned CO_2 capture facility and pipeline later this decade. We currently project that we will start to use CO_2 from Riley Ridge around 2020, following completion of the capture facility and planned CO_2 pipeline connecting Riley Ridge to our existing Greencore Pipeline.

Other Rocky Mountain CO_2 Sources. We began purchasing and receiving CO_2 from the Lost Cabin plant in central Wyoming in the first quarter of 2013, under a contract that provides us as much as 50 MMcf/d of CO_2 for use in our Rocky Mountain region CO_2 floods. Our volumes received from the plant averaged approximately 22 MMcf/d in 2013. We plan to continue to pursue additional sources for CO_2 supply in the Rocky Mountain region.

Greencore Pipeline. The 20-inch Greencore Pipeline in Wyoming is the first CO_2 pipeline we have constructed in the Rocky Mountain region. We plan to use the pipeline as our trunk line in the Rocky Mountain region, eventually connecting our Lost Cabin, LaBarge and Riley Ridge CO_2 sources (see *Rocky Mountain Region CO_2 Sources and Pipelines* above) to the Cedar Creek Anticline in eastern Montana. The initial 232-mile section of the Greencore Pipeline begins at the Lost Cabin gas plant in Wyoming and terminates at Bell Creek Field in Montana. We completed construction of this section of the pipeline in the fourth quarter of 2012 and received our first CO_2 deliveries from the Lost Cabin gas plant during the first quarter of 2013. In the first quarter of 2014, we completed construction of an interconnect between our Greencore Pipeline and an existing third-party CO_2 pipeline in Wyoming, which will enable us to transport CO_2 from LaBarge Field to our Bell Creek Field.

Tertiary Properties with Tertiary Production and Proved Tertiary Reserves at December 31, 2013

Bell Creek Field. Bell Creek Field is located in southeast Montana. The oil-producing reservoir in Bell Creek Field is a sandstone reservoir with characteristics similar to those we have successfully flooded with CO_2 in the Gulf Coast region; as a result, we believe it is well suited for CO_2 EOR. We acquired our interest in Bell Creek Field through the Encore merger in 2010 and have worked since that time to commence a CO_2 EOR project in the field. We began first CO_2 injections during the second quarter of 2013, recorded our first tertiary oil production in the third quarter of 2013, and booked initial proved tertiary reserves in the fourth quarter of 2013. Tertiary production, net to our interest, during the fourth quarter of 2013 averaged 177 Bbls/d. In 2014, we plan to invest approximately $55 million to expand our CO_2 flood of Bell Creek Field.

From inception through December 31, 2013, we had not yet recovered our investment in this field, and the remaining investment to be recovered (revenue less operating expenses and capital expenditures, including the acquisition costs) from Bell Creek Field was $432 million. As of December 31, 2013, the estimated PV-10 Value of Bell Creek Field was $739.0 million.

Future Tertiary Properties with No Tertiary Production or Proved Tertiary Reserves at December 31, 2013

Cedar Creek Anticline. CCA is the largest potential EOR property that we own and currently our largest producing property. The field is primarily located in Montana but covers such a large area (approximately 126 miles) that it also extends into North Dakota. CCA is a series of 14 producing areas, each of which could be considered a field by itself. We acquired our initial interest in CCA as part of the Encore merger in 2010 and acquired additional interests (the "CCA Acquisition") from a wholly-owned subsidiary of ConocoPhillips in the first quarter of 2013. See *2013 Business Developments* above and Note 2, *Acquisitions and Divestitures,* to the Consolidated Financial Statements for further discussion of this transaction and information as to other recent acquisitions and divestitures by Denbury.

The 2013 CCA Acquisition added 42.2 MMBOE of incremental proved reserves. Production from CCA, net to our interest, averaged 18,601 BOE/d during the fourth quarter of 2013, compared to pro forma production during the fourth quarter of 2012 of 19,493 BOE/d (including production associated with our newly acquired CCA assets of approximately 11,000 BOE/d and production from our previously owned CCA assets of 8,493 BOE/d). The non-tertiary proved reserves associated with CCA were 105.4 MMBbls of oil and 6.0 Bcf of gas as of December 31, 2013.

CCA is located approximately 110 miles north of Bell Creek Field, and we currently expect to ultimately connect this field to our Greencore Pipeline. In 2014, we plan to invest approximately $110 million to improve waterfloods, drill new wells, and recomplete existing wells. We currently plan to commence CO_2 injections at CCA after 2020.

Grieve Field. In the second quarter of 2011, we entered into a farm-in agreement, under which we will obtain a 65% working interest in Grieve Field, located in Natrona County, Wyoming, in exchange for developing the Grieve Field CO_2 flood. We completed a three-mile CO_2 pipeline to deliver CO_2 from an existing CO_2 pipeline to the Grieve Field in the fourth quarter of 2012, and are preparing for construction of the field's CO_2 recycle facility. We began injecting CO_2 into Grieve Field during the first quarter of 2013 and currently expect tertiary production to commence in 2015.

Hartzog Draw Field. We acquired our interest in Hartzog Draw Field in the fourth quarter of 2012 as part of the Bakken Exchange Transaction. The field is located in the Powder River Basin of northeastern Wyoming, approximately 12 miles from our Greencore Pipeline. Hartzog Draw Field had estimated proved reserves of approximately 5.2 MMBOE at December 31, 2013, net to our acquired interest, 1.9 MMBOE of which relate to the natural gas producing Big George coal zone. During the fourth quarter of 2013, non-tertiary production averaged 2,204 BOE/d. We believe the oil reservoir characteristics of Hartzog Draw Field make it well suited for CO_2 EOR. In 2014, we plan to invest approximately $40 million to drill and complete six horizontal wells in the Shannon formation and re-frac eight existing wells. We anticipate drilling additional horizontal wells in the Shannon formation over the next several years. The drilling of these wells is expected to generate near-term cash flow, as well as complement our planned future CO_2 EOR project in the field. We must obtain regulatory approval and construct a CO_2 pipeline from our existing Greencore Pipeline to Hartzog Draw Field before we can commence our planned CO_2 EOR project. We currently plan to commence CO_2 injections at Hartzog Draw Field after 2020.

Other Non-Tertiary Oil Properties

Although almost all of our oil and natural gas properties are either existing or planned future tertiary floods (discussed above), we also produce oil and natural gas either from fields that are not amenable to EOR or out of specific reservoirs (within an existing tertiary field) that are not amenable to EOR. For example, at Heidelberg Field, we produce natural gas from the Selma Chalk reservoir, which is separate from the Christmas and Eutaw reservoirs currently being flooded with CO_2. Production from these other non-tertiary properties totaled 6,994 BOE/d during the fourth quarter of 2013, compared to 18,615 BOE/d during the fourth quarter of 2012. Production during the fourth quarter of 2012 includes 10,064 BOE/d of production from our Bakken area assets that were sold during that period.

OIL AND GAS ACREAGE, PRODUCTIVE WELLS AND DRILLING ACTIVITY

In the data below, "gross" represents the total acres or wells in which we own a working interest and "net" represents the gross acres or wells multiplied by our working interest percentage. For the wells that produce both oil and gas, the well is typically classified as an oil or natural gas well based on the ratio of oil to natural gas production.

Oil and Gas Acreage

The following table sets forth our acreage position at December 31, 2013:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Gulf Coast region	250,732	211,058	390,678	40,383	641,410	251,441
Rocky Mountain region	362,163	311,687	188,055	83,647	550,218	395,334
Total	612,895	522,745	578,733	124,030	1,191,628	646,775

The percentage of our net undeveloped acreage that is subject to expiration over the next three years, if not renewed, is approximately 3% in 2014, 12% in 2015 and 12% in 2016.

Productive Wells

The following table sets forth our gross and net productive oil and natural gas wells as of December 31, 2013:

	Producing Oil Wells		Producing Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Operated wells:						
Gulf Coast region	1,233	1,140.1	212	192.6	1,445	1,332.7
Rocky Mountain region	1,160	1,039.0	201	111.2	1,361	1,150.2
Total	2,393	2,179.1	413	303.8	2,806	2,482.9
Non-operated wells:						
Gulf Coast region	33	0.9	—	—	33	0.9
Rocky Mountain region	72	8.7	101	37.5	173	46.2
Total	105	9.6	101	37.5	206	47.1
Total wells:						
Gulf Coast region	1,266	1,141.0	212	192.6	1,478	1,333.6
Rocky Mountain region	1,232	1,047.7	302	148.7	1,534	1,196.4
Total	2,498	2,188.7	514	341.3	3,012	2,530.0

Drilling Activity

The following table sets forth the results of our drilling activities over the last three years. As of December 31, 2013, we had 5 gross (4.8 net) wells in progress.

	Year Ended December 31,					
	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells: (1)						
Productive (2)	—	—	1	—	—	—
Non-productive (3)	—	—	—	—	1	0.7
Development wells: (1)						
Productive (2)	49	44.3	201	87.4	221	116.6
Non-productive (3)(4)	1	1.0	5	3.2	—	—
Total	50	45.3	207	90.6	222	117.3

(1) An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well. A development well is a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(2) A productive well is an exploratory or development well found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

(3) A non-productive well is an exploratory or development well that is not a productive well.

(4) During 2013, 2012 and 2011, an additional 43, 56 and 46 wells, respectively, were drilled for water or CO_2 injection purposes.

The following table summarizes sales volumes, sales prices and production cost information for our net oil and natural gas production for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31,		
	2013	2012	2011
Net sales volume:			
Gulf Coast region			
Oil (MBbls)	16,858	15,621	14,635
Natural gas (MMcf)	5,620	5,907	7,934
Total Gulf Coast region (MBOE)	17,795	16,606	15,957
Rocky Mountain region			
Oil (MBbls)	7,336	8,841	7,534
Natural gas (MMcf)	3,046	4,747	2,849
Total Rocky Mountain region (MBOE)	7,844	9,632	8,009
Total Company (MBOE)	25,639	26,238	23,966
Average sales price:			
Gulf Coast region			
Oil (per Bbl)	$105.34	$105.59	$105.23
Natural gas (per Mcf)	3.74	2.79	4.31
Rocky Mountain region			
Oil (per Bbl)	$ 89.95	$ 82.33	$ 89.93
Natural gas (per Mcf)	3.15	3.38	6.12
Total Company			
Oil (per Bbl)	$100.67	$ 97.18	$100.03
Natural gas (per Mcf)	3.53	3.05	4.79
Average production cost (per BOE sold): (1)			
Gulf Coast region (2)	$ 32.34	$ 24.96	$ 24.51
Rocky Mountain region	19.78	12.23	14.52
Total Company (2)	28.50	20.29	21.17

(1) Excludes oil and natural gas ad valorem and production taxes.

(2) Production costs include $114 million of lease operating expenses recorded during 2013 to remediate an area of Delhi Field. Excluding estimated Delhi Field remediation costs, average production costs in 2013 totaled $25.93 per BOE for the Gulf Coast Region and $24.05 per BOE for the Company as a whole.

PRODUCTION AND UNIT PRICES

Further information regarding average production rates, unit sale prices and unit costs per BOE are set forth under Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Operating Results Table,* included herein.

TITLE TO PROPERTIES

As is customary in the oil and natural gas industry, Denbury conducts a limited title examination at the time of its acquisition of properties or leasehold interests targeted for enhanced recovery, and curative work is performed with respect to significant defects on higher-value properties of the greatest significance. We believe that title to our oil and natural gas properties is good and defensible, subject only to such exceptions that we believe do not materially interfere with the use of such properties, including encumbrances, easements, restrictions and royalty, overriding royalty and other similar interests.

SIGNIFICANT OIL AND GAS PURCHASERS AND PRODUCT MARKETING

Oil and gas sales are made on a day-to-day basis under short-term contracts at the current area market price. The loss of any single purchaser would not be expected to have a material adverse effect upon our operations; however, the loss of a large single purchaser could potentially reduce the competition for our oil and natural gas production, which in turn could negatively impact the prices we receive. For the year ended December 31, 2013, three purchasers accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company (33%), Plains Marketing LP (15%), and Eighty-Eight Oil LLC (10%). For the years ended December 31, 2012 and 2011, two purchasers accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company (39% and 43% in 2012 and 2011, respectively) and Plains Marketing LP (17% and 16% in 2012 and 2011, respectively).

Our ability to market oil and natural gas depends on many factors beyond our control, including the extent of domestic production and imports of oil and gas, the proximity of our oil and natural gas production to pipelines, the available capacity in such pipelines, the demand for oil and natural gas, the effects of weather, and the effects of state and federal regulation. Our production in the Gulf Coast region is primarily from developed fields close to major pipelines or refineries and established infrastructure. Our production in the Rocky Mountain region is dependent on, among other factors, limited transportation options caused by oversubscribed pipelines and market centers that are distant from producing properties. As of December 31, 2013, we have not experienced significant difficulty in finding a market for all of our production as it becomes available or in transporting our production to those markets; however, there is no assurance that we will always be able to market all of our production or obtain favorable prices.

Oil Marketing

Over the past couple of years, the oil produced in the Gulf Coast region has benefited from strong pricing differentials in relation to NYMEX and, where possible, we have attached our production to Louisiana Light Sweet ("LLS") pricing. During 2013, LLS pricing and NYMEX pricing have been much closer together, with the fourth quarter of 2013 quarterly average LLS-to-NYMEX differential (on a trade-month basis) narrowing to a positive $2.58 per Bbl, suggesting a return to historical spreads compared to the wider-than-normal positive LLS-to-NYMEX spreads we experienced during 2012 and 2011. During 2013, our light sweet oil production in this area, on average, sold for $7.44 per Bbl over NYMEX compared to more than $11.50 per Bbl over NYMEX in 2012 and 2011. The pricing of other Gulf Coast grades was relatively consistent with NYMEX pricing in 2013, with our light and medium sour crude production selling at a premium to NYMEX of $0.08 per Bbl. The market dynamics of the region suggest the possibility that differentials to NYMEX will narrow due to the influx of light sweet crude and condensate from producing regions outside of the Gulf Coast region by rail and publicly announced major pipeline projects. Our current markets, at various sales points along the Gulf Coast, have sufficient demand to accommodate our production, but there can be no assurance of future demand. We are, therefore, monitoring the marketplace for opportunities to strategically enter into long-term marketing arrangements.

The marketing of our Rocky Mountain region oil production is dependent on transportation through local pipelines to market centers in Guernsey, Wyoming; Clearbrook, Minnesota; and Wood River, Illinois. Shipments on some of the pipelines are oversubscribed and subject to apportionment. We currently have access to sufficient pipeline capacity to move our oil production; however, there can be no assurance that we will be allocated sufficient pipeline capacity to move all of our oil production in the future. Expansion of pipeline and newly built rail infrastructure in the Rocky Mountain region is ongoing and, we believe, has improved the overall stability of oil differentials in the area. However, because local demand for production is small in comparison to current production levels, much of the production in the Rocky Mountain region is transported to coastal markets. Therefore, prices in the Rocky Mountain region are further influenced by fluctuations in prices (primarily Brent and LLS) in those coastal markets. For the year ended December 31, 2013, the discount for our oil production in the Rocky Mountain region averaged $8.10 per Bbl, compared to $11.86 per Bbl during 2012 and $5.15 per Bbl during 2011. Excluding the Bakken area assets that we sold during the fourth quarter of 2012, our oil production in the Rocky Mountain region sold at a discount to NYMEX of $8.43 per Bbl during the year ended December 31, 2012.

Overall, during 2013, we sold approximately 46% of our crude oil at prices based on the LLS index price, approximately 23% at prices partially tied to the LLS index price, and the balance at prices based on various other indexes tied to NYMEX prices, primarily in the Rocky Mountain region.

Natural Gas Marketing

Virtually all of our natural gas production in the Gulf Coast region is close to existing pipelines; consequently, we generally have a variety of options to market our natural gas. However, our natural gas production in the Rocky Mountain region, like our oil production, is dependent on, among other factors, limited transportation options that can affect our ability to find markets for it. We sell the majority of our natural gas on one-year contracts, with prices fluctuating month to month based on published pipeline indices and with slight premiums or discounts to the index. We currently receive near NYMEX or Henry Hub prices for most of our natural gas sales in Mississippi. For the year ended December 31, 2013, the amount received for our Mississippi natural gas production averaged $0.12 per Mcf over NYMEX prices. In the Texas Gulf Coast region, due primarily to its location, the price we received for the year ended December 31, 2013 averaged $0.12 per Mcf below NYMEX prices. The CCA natural gas production in the Rocky Mountain region is sold at the wellhead on a percent-of-proceeds basis. We receive a percentage of proceeds on both the residue natural gas volumes and the natural gas liquids volumes. The natural gas has a significant component of propane, butanes and other higher-density hydrocarbons, resulting in a measurable natural gas liquids stream. In addition, we have coal bed methane production in the Hartzog Draw that is sold at the

Cheyenne Hub. For the year ended December 31, 2013, we averaged $0.57 per Mcf below NYMEX prices for our Rocky Mountain region natural gas production due primarily to its location, the natural gas liquids extracted from the CCA gas stream (resulting in a decreased net price), and the quality of the coal bed methane gas in Wyoming.

Helium Marketing

We placed the Riley Ridge gas processing facility in service in the fourth quarter of 2013. During 2014, we expect to begin to supply helium to a third party purchaser under a 20-year helium supply arrangement. Helium will be sold under the contract at a price that will fluctuate based on helium deliveries, CPI and other factors over the 20-year term.

COMPETITION AND MARKETS

We face competition from other oil and natural gas companies in all aspects of our business, including acquisition of producing properties, oil and gas leases, drilling rights, and CO_2 properties; marketing of oil and natural gas; and obtaining and maintaining goods, services and labor. Many of our competitors have substantially larger financial and other resources. Factors that affect our ability to acquire producing properties include available liquidity, available information about prospective properties and our expectations for earning a minimum projected return on our investments. Because of the primary nature of our core assets (our tertiary operations) and our ownership of relatively uncommon significant natural sources of CO_2 in the Gulf Coast and Rocky Mountain regions, we believe that we are effective in competing in the market and have less competition than our peers in certain aspects of our business.

The demand for qualified and experienced field personnel to drill wells and conduct field operations and for geologists, geophysicists, engineers and other professionals in the oil and gas industry can fluctuate significantly, often in correlation with commodity prices, causing periodic shortages in such personnel. In recent years, the competition for qualified technical personnel has been extensive, and our personnel costs have been escalating. There have also been periods with shortages of drilling rigs and other equipment, as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. We cannot be certain when we will experience these issues, and these types of shortages or price increases could significantly decrease our profit margin, cash flow and operating results, and cause significant delays in our development operations.

FEDERAL AND STATE REGULATIONS

Numerous federal, state and local laws and regulations govern the oil and gas industry. Additions or changes to these laws and regulations are often made in response to the current political or economic environment. Compliance with this evolving regulatory burden is often difficult, and substantial penalties may be incurred for noncompliance. Additionally, the future annual cost of complying with all laws and regulations applicable to our operations is uncertain and will be ultimately determined by several factors, including future changes to legal and regulatory requirements. Management believes that continued compliance with existing laws and regulations applicable to our operations and future compliance therewith will not have a materially adverse effect on our consolidated financial position, results of operations or cash flows, although such laws and regulations, and compliance therewith, could cause significant delays or otherwise impede operations, which may, among other things, cause our expected production rates and cash flows to be less than anticipated.

The following sections describe some specific laws and regulations that may affect us. We cannot predict the cost or impact of these or other future legislative or regulatory initiatives.

Regulation of Natural Gas and Oil Exploration and Production

Our operations are subject to various types of regulation at the federal, state and local levels. Such regulation includes requiring permits for drilling wells; maintaining bonding requirements in order to drill or operate wells and regulating the location of wells; the method of drilling and casing wells; the surface use and restoration of properties upon which wells are drilled; the plugging and abandoning of wells; and the composition or disposal of chemicals and fluids used in connection with operations. Our operations are also subject to various conservation laws and regulations. These include regulation of the size of drilling, spacing or proration units and the density of wells that may be drilled in those units, and the unitization or pooling of oil and gas properties. In addition, state conservation laws, which establish maximum rates of production from oil and gas wells, generally prohibit or restrict the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. The effect of these laws and regulations may limit the amount of oil and natural gas we can produce from our wells and may limit the number of wells or the locations at which we can drill. The regulatory burden on the oil and gas industry increases our costs of doing business and, consequently, affects our profitability.

Federal Regulation of Sales Prices and Transportation

The transportation of, and certain sales with respect to, natural gas in interstate commerce are heavily regulated by agencies of the U.S. federal government and are affected by, among other things, the availability, terms and cost of transportation. Notably, the price and terms of access to pipeline transportation are subject to extensive U.S. federal and state regulation. The Federal Energy Regulatory Commission ("FERC") is continually proposing and implementing new and/or modified rules and regulations affecting the natural gas industry, some of which may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. While our sales of crude oil, condensate and natural gas liquids are not currently subject to FERC regulation, our ability to transport and sell such products is dependent on certain pipelines whose rates, terms and conditions of service are subject to FERC regulation. Additional proposals and proceedings that might affect the natural gas industry are considered from time to time by Congress, FERC, state regulatory bodies and the courts, and we cannot predict when or if any such proposals or proceedings might become effective and their effect or impact, if any, on our operations.

Federal Energy and Climate Change Legislation and Regulation

In early 2012, the President signed the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011. This act, among other things, updates federal pipeline safety standards, increases penalties for violations of such standards, gives the Department of Transportation (the "DOT") authority for new damage prevention and incident notification, and directs the DOT to prescribe new minimum safety standards for CO_2 pipelines, which safety standards could affect our operations and the costs thereof. While the DOT has adopted or proposed to adopt a number of new regulations to implement this act, no such new minimum safety standards have been proposed or adopted for CO_2 pipelines. In the future, Congress may create new incentives for alternative energy sources and may also consider legislation to reduce emissions of CO_2 or other greenhouse gases which legislation, if enacted, could (1) impose a tax or other economic penalty on the production of fossil fuels that, when used, ultimately release CO_2, (2) reduce the demand for, and uses of, oil, gas and other minerals, and/or (3) increase the costs incurred by us in our exploration and production activities. The Environmental Protection Agency ("EPA") has promulgated regulations requiring permitting for certain sources of greenhouse gas emissions, along with requirements for wells used for geologic sequestration. At the same time, legislation to reduce the emissions of CO_2 or other greenhouse gases could also create economic incentives for technologies and practices that reduce or avoid such emissions, including processes that sequester CO_2 in geologic formations such as depleted oil and gas reservoirs.

Natural Gas Gathering Regulations

State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory-take requirements. With the increase in construction and operation of natural gas gathering lines in various states, natural gas gathering is receiving greater regulatory scrutiny from state regulatory agencies, which is likely to continue in the future.

Federal, State or Indian Leases

Our operations on federal, state or Indian oil and gas leases, especially those in the Rocky Mountain region, are subject to numerous restrictions, including nondiscrimination statutes. Such operations must be conducted pursuant to certain on-site security regulations and other permits and authorizations issued by the Bureau of Land Management, the Bureau of Ocean Energy Management, the Bureau of Safety and Environmental Enforcement, the Bureau of Indian Affairs, and other federal and state stakeholder agencies.

Environmental Regulations

Our oil and natural gas production, saltwater disposal operations, injection of CO_2, and the processing, handling and disposal of materials such as hydrocarbons and naturally occurring radioactive materials ("NORM") are subject to stringent regulation. We could incur significant costs, including cleanup costs resulting from a release of product, third-party claims for property damage and personal injuries, or penalties and other sanctions as a result of any violations or liabilities under environmental or other laws applicable to our operations. Changes in, or more stringent enforcement of, environmental laws and other laws applicable to our operations could also result in delays or additional operating costs and capital expenditures.

Various federal, state and local laws and regulations controlling the discharge of materials into the environment, or otherwise relating to the protection of the environment, directly impact our oil and gas exploration, development and production operations. These include, among others, (1) regulations adopted by the EPA and various state agencies regarding approved methods of disposal for certain hazardous and nonhazardous wastes; (2) the Comprehensive Environmental Response, Compensation, and Liability Act and analogous state laws that regulate the removal or remediation of previously disposed wastes (including wastes disposed of or released by prior owners or operators), property contamination (including groundwater contamination), and remedial plugging operations to prevent future contamination; (3) the Clean Air Act and comparable state and local requirements already applicable to our operations and new restrictions on air emissions from our operations, including those that could discourage the production of fossil fuels that, when used, ultimately release CO_2; (4) the Oil Pollution Act of 1990, which contains numerous requirements relating to the prevention of, and response to, oil spills into waters of the United States; (5) the Resource Conservation and Recovery Act, which is the principal federal statute governing the treatment, storage and disposal of hazardous wastes; (6) the Endangered Species Act and counterpart state legislation, which protects certain species (and their related habitats), including certain species that could be present on our leases, as threatened or endangered; and (7) state regulations and statutes governing the handling, treatment, storage and disposal of NORM.

Management believes that we are currently in substantial compliance with existing applicable environmental laws and regulations, and does not currently anticipate that future compliance will have a materially adverse effect on our consolidated financial position, results of operations or cash flows, although such laws and regulations, and compliance therewith, could cause significant delays or otherwise impede operations, which may, among other things, cause our expected production rates and cash flows to be less than anticipated.

Hydraulic Fracturing

During 2013, we fracture stimulated one operated well at Hartzog Draw and two CO_2 source wells at Jackson Dome, in each case utilizing water-based fluids with no diesel fuel component. In 2014, we currently plan to hydraulically fracture approximately seven additional wells at Hartzog Draw using similar techniques. We are familiar with the laws and regulations applicable to hydraulic fracturing operations and take steps to ensure compliance with these requirements.

ESTIMATED NET QUANTITIES OF PROVED OIL AND NATURAL GAS RESERVES AND PRESENT VALUE OF ESTIMATED FUTURE NET REVENUES

Internal Controls Over Reserve Estimates

Reserve information in this report is based on estimates prepared by DeGolyer and MacNaughton ("D&M"), an independent petroleum engineering consulting firm located in Dallas, Texas, utilizing data provided by our internal reservoir engineering team and is the responsibility of management. We rely on D&M's expertise to ensure that our reserve estimates are prepared in compliance with SEC rules and regulations and that appropriate geologic, petroleum engineering, and evaluation principles and techniques are applied in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007)". The person responsible for the preparation of the reserve report is a Senior Vice President at D&M; he is a Registered Professional Engineer in the State of Texas. He received a Bachelor of Science degree in Petroleum Engineering at Texas A&M University in 1974, and he has in excess of 39 years of experience in oil and gas reservoir studies and evaluations. Our Senior Vice President – Planning, Technology and CO_2 Supply is primarily responsible for overseeing the independent petroleum engineering firm during the process. Our Senior Vice President – Planning, Technology and CO_2 Supply has a Bachelor of Science degree in Petroleum Engineering from Louisiana State University and over 32 years of industry experience working with petroleum reserve estimates. D&M relies on various data provided by our internal reservoir engineering team in preparing its reserve estimates, including such items as oil and natural gas prices, ownership interests, production information, operating costs, planned capital expenditures and other technical data. Our internal reservoir engineering team consists of qualified petroleum engineers who maintain the Company's internal evaluation of reserves and compare the Company's information to the reserves prepared by D&M. Management is responsible for designing the internal control procedures used in the preparation of our oil and gas reserves, which include verification of data input into reserve forecasting and economics evaluation software, as well as multi-discipline management reviews. The internal reservoir engineering team reports directly to our Senior Vice President – Planning, Technology and CO_2 Supply. In addition, our Board of Directors' Reserves and Health, Safety and Environment ("HSE") Committee, on behalf of the Board of Directors, oversees the qualifications, independence, performance and hiring of our independent petroleum engineering firm and reviews the final report and subsequent reporting of our oil and natural gas reserve estimates. The Chairman of the Reserves and HSE Committee holds a Ph.D. in Chemical Engineering from the Massachusetts Institute of Technology and bachelor's degrees in Chemistry and Mathematics from Capital University in Ohio. He has 34 years of industry experience, with responsibilities including reserves preparation and approval.

Oil and Natural Gas Reserve Estimates

D&M prepared estimates of our net proved oil and natural gas reserves as of December 31, 2013, 2012 and 2011. See the summary of D&M's report as of December 31, 2013, included as an exhibit to this Form 10-K. These estimates of reserves were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices on the first day of each month within the 12-month period in accordance with rules and regulations of the SEC. These oil and natural gas reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interest in our properties. During 2013, we provided oil and gas reserve estimates for 2012 to the United States Energy Information Agency that were substantially the same as the reserve estimates included in our Form 10-K for the year ended December 31, 2012.

Our proved nonproducing reserves primarily relate to reserves that are to be recovered from productive zones that are currently behind pipe. Since a majority of our properties are in areas with multiple pay zones, these properties typically have both proved producing and proved nonproducing reserves.

As of December 31, 2013, our estimated proved undeveloped reserves totaled approximately 179.9 MMBOE, or approximately 38% of our estimated total proved reserves, an increase of 17.2 MMBOE from December 31, 2012 levels. Our proved undeveloped oil reserves primarily relate to our CO_2 tertiary operations (92.8 MMBOE), and our proved undeveloped natural gas reserves are primarily located in our Riley Ridge Field (66.6 MMBOE). We consider the CO_2 tertiary proved undeveloped reserves to be lower risk than other proved undeveloped reserves that require drilling at locations offsetting existing production, because all of these proved undeveloped reserves are associated with tertiary recovery operations in fields and reservoirs that historically produced substantial volumes of oil under primary production.

During 2013, we spent approximately $260 million to convert 16.7 MMBOE of proved undeveloped reserves to proved developed reserves, primarily as a result of tertiary development activities at Heidelberg, Hastings, and Tinsley fields. During 2013, we added 30.0 MMBOE of proved undeveloped reserves, including 27.3 MMBOE related to our tertiary operations at Bell Creek Field, and recognized net positive proved undeveloped reserve revisions of 3.9 MMBOE.

As of December 31, 2013, 26.7 MMBOE of our total proved undeveloped reserves are not scheduled to be developed within five years of initial booking, 26.1 MMBOE of which are part of CO_2 EOR projects. We believe these reserves satisfy the conditions to be included as proved reserves because (1) we have established and continue to follow the previously adopted development plan for each of these projects; (2) we have significant ongoing development activities in each of these CO_2 EOR projects and (3) we have a historical record of completing the development of comparable long-term projects.

	December 31, 2013	2012	2011
Estimated proved reserves (1)			
Oil (MBbls)	386,659	329,124	357,733
Natural gas (MMcf)	489,954	481,641	625,208
Oil equivalent (MBOE)	468,318	409,398	461,934
Reserve volumes categories			
Proved developed producing:			
Oil (MBbls)	245,722	208,745	189,904
Natural gas (MMcf)	68,976	60,832	116,562
Oil equivalent (MBOE)	257,218	218,884	209,331
Proved developed non-producing:			
Oil (MBbls)	30,670	27,264	49,837
Natural gas (MMcf)	3,119	3,359	9,408
Oil equivalent (MBOE)	31,190	27,824	51,405
Proved undeveloped:			
Oil (MBbls)	110,267	93,115	117,992
Natural gas (MMcf)	417,859	417,450	499,238
Oil equivalent (MBOE)	179,910	162,690	201,198
Percentage of total MBOE:			
Proved developed producing	55%	53%	45%
Proved developed non-producing	7%	7%	11%
Proved undeveloped	38%	40%	44%
Representative oil and natural gas prices: (2)			
Oil – NYMEX	$ 96.94	$ 94.71	$ 96.19
Natural gas – Henry Hub	3.67	2.85	4.16
Present values (in thousands): (3)			
Discounted estimated future net cash flow before income taxes (PV-10 Value) (4)	$10,633,783	$9,909,592	$10,559,139
Standardized measure of discounted estimated future net cash flow after income taxes ("Standardized Measure")	$ 7,128,744	$6,414,380	$ 7,007,605

(1) Estimated proved reserves as of December 31, 2012 reflect the sale of reserves associated with our Bakken area assets sold in 2012 (approximately 109 MMBOE). Year-end 2012 reserves reflect CCA reserves acquired in 2010 as part of the Encore merger, but do not include reserves of 42.2 MMBOE related to the CCA Acquisition, which closed during the first quarter of 2013.

(2) The reference prices were based on the arithmetic average of the first-day-of-the-month NYMEX commodity prices for each month during the respective year. These prices do not reflect adjustments for market differentials by field that are utilized in the preparation of our reserve report to arrive at the appropriate net price we receive. See *Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Operating Results Table* for details of oil and natural gas prices received, both including and excluding the impact of derivative settlements.

(3) Determined based on the average first-day-of-the-month prices for each month, adjusted to prices received by field in accordance with standards set forth in the FASC.

(4) PV-10 Value is a non-GAAP measure and is different from the Standardized Measure in that PV-10 Value is a pre-tax number and the Standardized Measure is an after-tax number. The information used to calculate PV-10 Value is derived directly from data determined in accordance with FASC Topic 932. The difference between these two amounts, the discounted estimated future income tax was $3.505 billion at December 31, 2013; $3.495 billion at December 31, 2012; and $3.552 billion at December 31, 2011. We believe that PV-10 Value is a useful supplemental disclosure to the Standardized Measure because the Standardized Measure can be impacted by a company's unique tax situation, and it is not practical to calculate the Standardized Measure on a property-by-property basis. Because of this, PV-10 Value is a widely used measure within the industry and is commonly used by securities analysts, banks and credit rating agencies to evaluate the estimated future net cash flows from proved reserves on a comparative basis across companies or specific properties. PV-10 Value is commonly used by us and others in our industry to evaluate properties that are bought and sold and to assess the potential return on investment in our oil and gas properties. PV-10 Value is not a measure of financial or operating performance under GAAP, nor should it be considered in isolation or as a substitute for the Standardized Measure. Our PV-10 Value and the Standardized Measure do not purport to represent the fair value of our oil and natural gas reserves. See *Glossary and Selected Abbreviations* for the definition of "PV-10 Value" and see *Supplemental Oil and Natural Gas Disclosures (Unaudited),* to the Consolidated Financial Statements for additional disclosures about the Standardized Measure.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and their values, including many factors beyond our control. See Item 1A, *Risk Factors – Estimating our reserves, production and future net cash flows is difficult to do with any certainty.* See also *Supplemental Oil and Natural Gas Disclosures (Unaudited),* to the Consolidated Financial Statements.

Item 1A. Risk Factors

Oil and natural gas prices are volatile. A substantial decrease in oil and natural gas prices could adversely affect our financial results.

Our future financial condition, results of operations, cash flows and the carrying value of our oil and natural gas properties depend primarily upon the prices we receive for our oil and natural gas production. Oil and natural gas prices historically have been volatile and may continue to be volatile in the future. Substantial decreases in commodity prices in the future could require us to record full cost ceiling test write-downs. The amount of any future write-down is difficult to predict and will depend upon oil and natural gas prices, the incremental proved reserves that might be added during each period and additional capital spent.

Our cash flow from operations is highly dependent on the prices that we receive for oil. This price volatility also affects the amount of our cash flow available for capital expenditures and our ability to borrow money or raise additional capital. Oil prices currently affect us more than natural gas prices because oil comprised approximately 94% of our 2013 production and 83% of our proved reserves at December 31, 2013.

The prices for oil and natural gas are subject to a variety of additional factors that are beyond our control. These factors include the supply of, and demand for, these commodities, which fluctuate with changes in market and economic conditions and other factors, including:

- the level of worldwide consumer demand for oil and natural gas;
- the domestic and foreign supply of oil and natural gas;
- the degree to which domestic oil and natural gas production decreases U.S. imports of crude oil;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- domestic governmental regulations and taxes;
- the price and availability of alternative fuel sources;
- storage levels of oil and natural gas;
- weather conditions, including hurricanes and tropical storms in and around the Gulf of Mexico that can damage oil and natural gas facilities and delivery systems and disrupt operations, and winter conditions and forest fires in the Rocky Mountains that can delay or impede operations;
- market uncertainty;
- worldwide political events and conditions, including actions taken by foreign oil and natural gas producing nations; and
- worldwide economic conditions.

These factors and the volatility of the energy markets generally make it extremely difficult to predict future oil and natural gas price movements. Also, prices for oil and prices for natural gas do not necessarily move in tandem. Declines in oil or natural gas prices would not only reduce revenue but could reduce the amount of oil and natural gas that we can produce economically. If the oil and natural gas industry experiences significant price declines, we may, among other things, be unable to meet all of our financial obligations or make planned expenditures.

Over the past six years oil prices have fluctuated significantly, reaching record highs of approximately $145 per Bbl in July 2008, declining precipitously during the last half of 2008, and ending that year at a NYMEX price of $44.60 per Bbl. Since 2008, oil prices have continued to fluctuate, ending 2013 at a NYMEX price of $98.42 per Bbl. If substantial volatility of oil prices continues, oil prices could decline to a level that makes some or all of our tertiary projects uneconomical. If that were to happen, we may decide to suspend future expansion projects, and if prices were to drop below our cash break-even point for an extended period of time, we may further decide to shut-in existing production, both of which could have a material adverse effect on our operations. We may also be required to reduce our capital expenditures in the event of declining commodity prices in order to compensate for diminished cash flow, which could reduce or eliminate our growth. Since operating costs do not decrease as quickly as commodity prices, it is difficult to determine a precise break-even point for our tertiary projects; however, based on prior history, we currently estimate our economic break-even point (before corporate-related overhead and based on currently estimated expenses relative to these tertiary projects) occurs at oil prices in the low-to-mid $40-per-barrel range, depending on the specific field and area.

We have a current practice of hedging approximately 18 months to two years (from the current quarter) of forecasted production to mitigate the risks associated with price fluctuations (see *Management's Discussion and Analysis of Financial Condition and Results of Operations – Market Risk Management* and Note 9, *Commodity Derivative Contracts,* to the Consolidated Financial Statements for details regarding our commodity derivative contracts). As of February 20, 2014, we have oil derivative contracts in place covering 58,000 Bbls/d during 2014 and 58,000 Bbls/d during the first three quarters of 2015.

The prices we receive for our crude oil often do not correlate with NYMEX prices and can vary from such prices depending on, among other factors, the quality of the crude oil we sell, the location of our crude oil production and the related markets to which we sell, variations in prices paid based upon different indices used, and the pricing contracts and indices at which we sell production. Our NYMEX differentials on a field-by-field basis over the last few years have ranged from approximately $25 per Bbl above NYMEX to approximately $25 per Bbl below NYMEX. On a corporate-wide basis, our NYMEX differentials over the last few years have ranged from approximately $11 per Bbl above NYMEX oil prices to approximately $5 per Bbl below NYMEX oil prices. These variances have been due to various factors and are difficult to forecast or anticipate, but they have a direct impact on the net oil price we receive.

Natural gas price volatility has been severe over the last few years as a result of, among other things, weak demand, increased production of natural gas, and significant natural gas storage in place, leading to excess gas supply. NYMEX natural gas prices averaged $4.03 per MMBtu during 2011, $2.82 per MMBtu during 2012, and $3.72 per MMBtu during 2013, and ended 2013 at $4.23 per MMBtu. As of February 20, 2014, we have natural gas derivative contracts in place covering 14,000 MMBtu/d during 2014 and 6,000 MMBtu/d during 2015 (see *Management's Discussion and Analysis of Financial Condition and Results of Operations – Market Risk Management* and Note 9, C*ommodity Derivative Contracts,* to the Consolidated Financial Statements for details regarding our commodity derivative contracts).

Our production will decline if our access to sufficient amounts of carbon dioxide is limited.

Our long-term strategy is focused on our CO_2 tertiary recovery operations. The crude oil production from our tertiary recovery projects depends, in large part, on having access to sufficient amounts of CO_2. Our ability to produce oil from these projects would be hindered if our supply of CO_2 was limited due to, among other things, problems with our current CO_2 producing wells and facilities, including compression equipment, or catastrophic pipeline failure. This could have a material adverse effect on our financial condition, results of operations and cash flows. Our anticipated future crude oil production from tertiary operations is also dependent on the timing, volumes and location of CO_2 injections and, in particular, on our ability to increase our combined purchased and produced volumes of CO_2 and inject adequate amounts of CO_2 into the proper formation and area within each of our tertiary oil fields.

Our planned tertiary operations and the related construction of necessary CO_2 pipelines could be delayed by difficulties in obtaining pipeline rights-of-way and/or permits, and/or by the listing of certain species as threatened or endangered.

The production of crude oil from our planned tertiary operations is dependent upon having access to pipelines to transport available CO_2 to our oil fields at a cost that is economically viable. Our current and future construction of CO_2 pipelines will require us to obtain rights-of-way from private landowners and from the federal government in certain areas. Certain states where we operate are considering the adoption of laws and regulations that would limit or eliminate a state's (and, accordingly, its legislative delegates') ability to exercise eminent domain over private property, in addition to possible judicially imposed constraints on, and additional requirements for, the exercise of eminent domain. We also conduct operations on federal and other oil and natural gas leases inhabited by species, such as the sage grouse, that could be listed as threatened or endangered under the Endangered Species Act, which listing could lead to material restrictions as to federal land use. These laws and regulations, together with any other changes in law related to the use of eminent domain or the listing of certain species as threatened or endangered, could inhibit or eliminate our ability to secure rights-of-way or otherwise access land for current or future pipeline construction projects. As a result, obtaining rights-of-way or other means of access may require additional regulatory and environmental compliance, and increased costs in connection therewith, which could delay our CO_2 pipeline construction schedule and initiation of our pipeline operations, and/or increase the costs of constructing our pipelines.

Our level of indebtedness may adversely affect operations and limit our growth.

As of December 31, 2013, our outstanding senior indebtedness consisted of $2.6 billion principal amount of subordinated notes, virtually all of which have maturity dates between 2020 and 2023 at interest rates ranging from 4.625% to 8.25% per annum at a weighted average interest rate of 6.29% per annum, and $340.0 million principal amount outstanding under our bank credit facility. We currently have a borrowing base of $1.6 billion under our bank credit facility and, at December 31, 2013, availability with respect to such borrowing base of $1.2 billion. Our bank borrowing base is adjusted semi-annually and upon requested special redeterminations, in each case at the banks' discretion, and the amount is established and based, in part, upon certain external factors, such as commodity prices, over which we have no control. If the outstanding credit under our bank credit facility exceeds the then effective and redetermined borrowing base, we will be required to repay the excess amount over a period not to exceed four months.

We may incur additional indebtedness in the future under our bank credit facility in connection with, among other things, our acquisition and development of oil and natural gas properties. Further, as our cash flow from operations is highly dependent on the prices that we receive for oil and natural gas, if oil and natural gas prices decrease substantially and remain at depressed levels for an extended period of time, our degree of leverage could increase significantly. The level of our indebtedness could have important consequences, including but not limited to the following:

- our level of indebtedness may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions or general corporate and other purposes;
- our vulnerability to general adverse economic and industry conditions may be greater as a result of our level of indebtedness, and increases in interest rates thereon, potentially restricting us from making acquisitions, introducing new technologies or exploiting business opportunities;
- our interest expense may increase in the event of increases in market interest rates;
- a substantial portion of our cash flows from operations may be dedicated to servicing our indebtedness and would not be available for capital expenditures or other purposes;
- our ability to, among other things, borrow additional funds, dispose of assets, pay dividends and make certain investments may be limited by the covenants contained in the agreements governing our outstanding indebtedness; and
- our debt covenants contained in the agreements governing our outstanding indebtedness may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry, and our failure to comply with such covenants could result in an event of default under such debt instruments which, if not cured or waived, could have a material adverse effect on us.

If we are unable to generate sufficient cash flow or otherwise obtain funds necessary to make required payments on our indebtedness, or if we otherwise fail to comply with the various covenants related to such indebtedness, including covenants in our bank credit facility, we would be in default under our debt instruments. This default could permit the holders of such indebtedness to accelerate the maturity of such indebtedness and could cause defaults under other indebtedness, which could have a material adverse effect on us. Our ability to meet our obligations under our debt instruments will depend, in part, upon our future performance, which will be subject to prevailing economic conditions, commodity prices, and financial, business and other factors, including factors beyond our control.

Commodity derivative contracts may expose us to potential financial loss.

To reduce our exposure to fluctuations in the prices of oil and natural gas, we enter into commodity derivative contracts in order to economically hedge a substantial portion of our oil and natural gas production. Derivative contracts expose us to risk of financial loss in some circumstances, including when there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received, or when the counterparty to the derivative contract defaults on its contractual obligations. In addition, these derivative contracts may limit the benefit we would otherwise receive from increases in the prices for oil and natural gas. Information as to these activities is set forth under Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – Market Risk Management,* and in Note 9, *Commodity Derivative Contracts,* to the Consolidated Financial Statements.

There are no assurances of our ability to pay dividends in the future and at what level.

On January 28, 2014, we declared our first quarterly cash common stock dividend of $0.0625 per share, payable March 25, 2014, to shareholders of record on February 25, 2014. We currently intend to pay regular quarterly cash dividends in the future; however, our ability to pay dividends may be adversely affected if certain of the risks described herein were to occur. Our payment of dividends is subject to, and conditioned upon, among other things, compliance with the covenants and restrictions contained in our bank credit facility and the indentures governing our subordinated notes. All dividends will be paid at the discretion of our Board of Directors and will depend upon many factors, including our earnings, financial condition and such other factors as our Board of Directors may deem relevant from time to time. There are no assurances as to our ability to pay dividends in the future or the level thereof.

A worldwide financial downturn or negative credit market conditions may have lasting effects on our liquidity, business and financial condition that we cannot control or predict.

Liquidity is essential to our business. Our liquidity could be substantially negatively affected by an inability to obtain capital in the long-term or short-term debt capital markets or equity capital markets or an inability to access bank financing. A prolonged credit crisis, including a sovereign debt crisis in Europe or turmoil in the global financial system, could materially affect our liquidity, business and financial condition. These conditions have adversely impacted financial markets and have created substantial volatility and uncertainty, and may continue to do so, with the related negative impact on global economic activity and the financial markets. Negative credit market conditions could materially affect our liquidity and may inhibit our lenders from fully funding our bank credit facility or cause them to make the terms of our bank credit facility more costly and more restrictive. We are subject to semiannual, as well as unscheduled, reviews and redeterminations of our borrowing base under our bank credit facility, and we do not know, nor can we control, the results of such redeterminations or the effect of then-current oil and natural gas prices on any such redetermination. A negative economic situation could also adversely affect the collectability of our trade receivables or performance by our suppliers and cause our commodity hedging arrangements to be ineffective if our counterparties are unable to perform their obligations or otherwise seek bankruptcy protection. Additionally, negative economic conditions could lead to reduced demand for oil and natural gas, or lower prices for oil and natural gas, which could have a negative impact on our revenues.

Our future performance depends upon our ability to find or acquire additional oil and natural gas reserves that are economically recoverable.

Unless we can successfully replace the reserves that we produce, our reserves will decline, resulting eventually in a decrease in oil and natural gas production and lower revenues and cash flows from operations. We have historically replaced reserves through both acquisitions and internal organic growth activities. In the future, we may not be able to continue to replace reserves at acceptable costs. The business of exploring for, developing or acquiring reserves is capital intensive. We may not be able to make the necessary capital investment to maintain or expand our oil and natural gas reserves if our cash flows from operations are reduced, whether due to lower oil or natural gas prices or otherwise, or if external sources of capital become limited or unavailable. Further, the process of using CO_2 for tertiary recovery, and the related infrastructure, requires significant capital investment up to five years prior to any resulting and associated production and cash flows from these projects, heightening potential capital constraints. If we do not continue to make significant capital expenditures, or if outside capital resources become limited, we may not be able to maintain our growth rate or otherwise meet expectations.

During the last few years, we have acquired several fields at a substantial cost because we believe that they have significant additional production potential through tertiary flooding, and we plan to continue acquiring other oil fields that we believe are tertiary flood candidates. We are investing significant amounts of capital as part of this strategy. If we are unable to successfully develop and produce the potential oil in these acquired fields, it would negatively affect our return on investment relative to these acquisitions and could significantly reduce our ability to obtain additional capital for the future or fund future acquisitions, and also negatively affect our financial results to a significant degree.

Oil and natural gas development and producing operations involve various risks.

Our operations are subject to all the risks normally incident and inherent to the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells, including, without limitation, well blowouts; cratering and explosions; pipe failure; fires; formations with abnormal pressures; uncontrollable flows of oil, natural gas, brine or well fluids; release of contaminants into the environment and other environmental hazards and risks.

The nature of these risks is such that some liabilities could exceed our insurance policy limits or otherwise be excluded from, or limited by, our insurance coverage, as in the case of environmental fines and penalties, for example, which are excluded from coverage as they cannot be insured. We could incur significant costs related to these risks that could have a material adverse effect on our results of operations, financial condition and cash flows.

Our CO_2 tertiary recovery projects require a significant amount of electricity to operate the related facilities. If these costs were to increase significantly, it could have an adverse effect upon the profitability of these operations. Additionally, a portion of our production activities involves CO_2 injections into fields with wells plugged and abandoned by prior operators. Although it is often difficult (or impracticable) to determine whether a well has been properly plugged prior to commencing injections and pressuring the oil reservoirs, we have budgeted $50 million for this effort for 2014. We may incur significant costs in connection with remedial plugging operations to prevent environmental contamination and to otherwise comply with federal, state and local regulation relative to the plugging and abandoning of our oil, natural gas and CO_2 wells. In addition to the increased costs, if wells have not been properly plugged, modification to those wells may delay our operations and reduce our production.

While mitigated somewhat by our significant emphasis on tertiary recovery operations in fields and reservoirs that have historically produced substantial volumes of oil under primary production, development activities are subject to many risks, including the risk that new wells drilled by us will not result in the discovery of commercially productive reservoirs or the risk that we will not recover all or any portion of our investment in such wells. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Further, our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions, including hurricanes and tropical storms in and around the Gulf of Mexico that can damage oil and natural gas facilities and delivery systems and disrupt operations, and winter conditions and forest fires in the Rocky Mountain region that can delay or impede operations;
- compliance with environmental and governmental requirements; and
- the cost of, or shortages or delays in the availability of, drilling rigs, equipment, pipelines and services.

Certain of our operations may be limited during certain periods due to severe weather conditions and other regulations.

Certain of our operations in North Dakota, Montana and Wyoming, including the construction of CO_2 pipelines, the drilling of new wells and production from existing wells, are conducted in areas subject to extreme weather conditions, including severe cold, snow and rain, which conditions may cause such operations to be hindered or delayed, or otherwise require that they be conducted only during non-winter months, and depending on the severity of the weather, could have a negative effect on our results of operations in these areas. Further, certain of our operations in these areas are confined to certain time periods due to environmental regulations, federal restrictions on when drilling can take place on federal lands, and lease stipulations designed to protect certain wildlife, which regulations, restrictions and limitations could slow down our operations, cause delays, increase costs and have a negative effect on our results of operations.

Shortages of oil field equipment, services and qualified personnel could reduce our cash flow and adversely affect results of operations.

The demand for qualified and experienced field personnel, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages in such personnel. In recent years, the competition for qualified technical personnel has been fierce, and our personnel costs have been escalating at a rate higher than general inflation. During periods of high oil and natural gas prices, we have experienced shortages of oil field and other necessary equipment, as well as drilling rigs, as demand for equipment and rigs has increased in tandem with higher commodity prices. Additionally, higher oil and natural gas prices generally stimulate increased demand, which results in increased prices for drilling rigs, crews and associated supplies, oilfield equipment and services, and personnel in our exploration and production operations. These types of shortages or price increases could significantly decrease our profit margin, cash flow and operating results and/or restrict or delay our ability to drill wells and conduct those operations that we currently have planned and budgeted, causing us to miss our forecasts and projections.

The marketability of our production is dependent upon transportation lines and other facilities, certain of which we do not control. When these facilities are unavailable, our operations can be interrupted and our revenues reduced.

The marketability of our oil and natural gas production depends, in part upon the availability, proximity and capacity of transportation lines owned by third parties. In general, we do not control these transportation facilities, and our access to them may be limited or denied. A significant disruption in the availability of, and access to, these transportation lines or other production facilities could adversely impact our ability to deliver to market or produce our oil and thereby cause a significant interruption in our operations.

Governmental laws and regulations relating to environmental protection are costly and stringent.

Our exploration, production, and marketing operations are subject to complex and stringent federal, state, and local laws and regulations governing, among other things, the discharge of substances into the environment or otherwise relating to environmental protection. These laws and regulations and related public policy considerations affect the costs, manner, and feasibility of our operations and require us to make significant expenditures in order to comply. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial obligations, and the issuance of injunctions that could limit or prohibit our operations. In addition, some of these laws and regulations may impose joint and several, strict liability for contamination resulting from spills, discharges, and releases of substances, including petroleum hydrocarbons and other wastes, without regard to fault or the legality of the original conduct. Under such laws and regulations, we could be required to remove or remediate previously disposed substances and property contamination, including wastes disposed or released by prior owners or operators. Changes in, or additions to, environmental laws and regulations occur frequently, and any changes or additions that result in more stringent and costly waste handling, storage, transport, disposal, cleanup or other environmental protection requirements could have a material adverse effect on our operations and financial position.

Enactment of legislative or regulatory proposals under consideration could negatively affect our business.

Numerous legislative and regulatory proposals affecting the oil and gas industry have been introduced, are anticipated to be introduced, or are otherwise under consideration, by Congress and various federal agencies. Among these proposals are: (1) climate change/carbon tax legislation introduced in Congress, and EPA regulations to reduce greenhouse gas emissions; (2) proposals contained in the President's budget, along with legislation introduced in Congress (none of which have passed), to impose new taxes on, or repeal various tax deductions available to, oil and gas producers, such as the current tax deductions for intangible drilling and development costs and qualified tertiary injectant expenses which deductions, if eliminated, could raise the cost of energy production, reduce energy investment and affect the economics of oil and gas exploration and production activities; (3) legislation previously considered by Congress (but not adopted) that would subject the process of hydraulic fracturing to federal regulation under the Safe Drinking Water Act, and new or anticipated Department of Interior and EPA regulations to impose new and more stringent regulatory requirements on hydraulic fracturing activities, particularly those performed on federal lands, and to require disclosure of the chemicals used in the fracturing process; and (4) the Pipeline Safety, Regulatory Certainty, and Job Creation Act enacted in 2011, which increases penalties, grants new authority to impose damage prevention and incident notification requirements, and directs the Department of Transportation to prescribe minimum safety standards for CO_2 pipelines. Any of the foregoing described proposals could affect our operations and the costs thereof. The trend toward stricter standards, increased oversight and regulation and more extensive permit requirements, along with any future laws and regulations, could result in increased costs or additional operating restrictions that could have an effect on demand for oil and natural gas or prices at which it can be sold. However, until such legislation or regulations are enacted or adopted into law and thereafter implemented, it is not possible to gauge their impact on our future operations or our results of operations and financial condition.

Certain federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated, and additional state taxes on natural gas extraction may be imposed, as a result of future legislation.

In recent years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. federal income tax laws, including the elimination of certain U.S. federal income tax benefits and deductions currently available to oil and gas companies. Such changes include, but are not limited to, (1) the repeal of the percentage depletion allowance for oil and gas properties, (2) the increase of the amortization period of geological and geophysical expenses, (3) the elimination of current deductions for intangible drilling and development costs and qualified tertiary injectant expenses, and (4) the elimination of the deduction for certain U.S. production activities. It is currently unclear whether any such proposals will be enacted into law and, if so, what form such laws might possibly take or impact they may have; however, the passage of such legislation or any other similar change in U.S. federal income tax law could eliminate, reduce or postpone certain tax deductions that are currently available to us, and any such legislation or change could negatively affect our financial condition and results of operations.

The derivatives market regulations promulgated under the Dodd-Frank Act could have an adverse effect on our ability to hedge risks associated with our business.

The Dodd-Frank Act requires the Commodities Futures Trading Commission ("CFTC") and the SEC to promulgate rules and regulations establishing federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market, including swap clearing and trade execution requirements. Our derivative transactions are not currently subject to such swap clearing and trade execution requirements; however, in the event our derivative transactions potentially become subject to such requirements, we believe that our derivative transactions would qualify for the "end-user" exception. New or modified rules, regulations or requirements may increase the cost and availability to our counterparties of their hedging and swap positions that they can make available to us, and may further require the counterparties to our derivative instruments to spin off some of their derivative activities to separate entities that may not be as creditworthy as the current counterparties. In addition, for uncleared swaps, the CFTC or federal banking regulators may require end-users to enter into credit support documentation or post margin collateral. Any changes in the regulations of swaps may result in certain market participants deciding to curtail or cease their derivative activities.

While many rules and regulations have been promulgated and are already in effect, other rules and regulations, including the proposed margin rules, remain to be finalized or effectuated; therefore, the impact of those rules and regulations on us is uncertain at this time. The Dodd-Frank Act, and the rules promulgated thereunder, could (1) significantly increase the cost, or decrease the liquidity, of energy-related derivatives we use to hedge against commodity price fluctuations (including through requirements to post collateral), (2) materially alter the terms of derivative contracts, (3) reduce the availability of derivatives to protect against risks we encounter, and (4) increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and applicable rules and regulations, our cash flow may become more volatile and less predictable, which could adversely affect our ability to plan for and fund capital expenditures.

The loss of one or more of our large oil and natural gas purchasers could have an adverse effect on our operations.

For the year ended December 31, 2013, three purchasers individually accounted for 10% or more of our oil and natural gas revenues and, in the aggregate, for 58% of such revenues. The loss of a large single purchaser could adversely impact the prices we receive or the transportation costs we incur.

Estimating our reserves, production and future net cash flows is difficult to do with any certainty.

Estimating quantities of proved oil and natural gas reserves is a complex process. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors such as future commodity prices, production costs, severance and excise taxes, capital expenditures and workover and remedial costs, and the assumed effect of governmental rules and regulations. There are numerous uncertainties about when a property may have proved reserves as compared to potential or probable reserves, particularly relating to our tertiary recovery operations. Forecasting the amount of oil reserves recoverable from tertiary operations, and the production rates anticipated therefrom, requires estimates, one of the most significant being the oil recovery factor. Actual results most likely will vary from our estimates. Also, the use of a 10% discount factor for reporting purposes, as prescribed by the SEC, may not necessarily represent the most appropriate discount factor, given actual interest rates and risks to which our business, and the oil and natural gas industry in general, are subject. Any significant inaccuracies in these interpretations or assumptions, or changes of conditions, could result in a reduction of the quantities and net present value of our reserves.

The reserves data included in documents incorporated by reference represent estimates only. Quantities of proved reserves are estimated based on economic conditions, including first-day-of-the-month average oil and natural gas prices for the 12-month period preceding the date of the assessment. Our reserves and future cash flows may be subject to revisions based upon changes in economic conditions, including oil and natural gas prices, as well as due to production results, results of future development, operating and development costs, and other factors. Downward revisions of our reserves could have an adverse effect on our financial condition and operating results. Actual future prices and costs may be materially higher or lower than the prices and costs used in our estimates.

As of December 31, 2013, approximately 38% of our estimated proved reserves were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and may require successful drilling operations. The reserves data assumes that we can and will make these expenditures and conduct these operations successfully, but these assumptions may not be accurate, and these expenditures and operations may not occur.

Significant acquisitions or other transactions could require substantial external capital and could change our risk and property profile.

To finance acquisitions, we may need to substantially alter or increase our capitalization through the use of our bank credit facility, the issuance of debt or equity securities, the sale of production payments, or by other means. Such changes in capitalization could significantly affect our risk profile. Additionally, significant acquisitions or other transactions can change the character of our operations and business. The character of the new properties may be substantially different in operating or geological characteristics or geographic location from that of our existing properties.

Our results of operations could be negatively affected as a result of goodwill impairments.

At December 31, 2013, the Company's goodwill balance totaled $1.3 billion and represented approximately 10.9% of our total assets. Goodwill is not amortized; rather it is tested for impairment annually during the fourth quarter and when facts or circumstances indicate that the carrying value of the Company's goodwill may be impaired, requiring an estimate of the fair values of the reporting unit's assets and liabilities. An impairment of goodwill could significantly reduce earnings during the period in which the impairment occurs and would result in a corresponding reduction to goodwill and equity. See Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies and Estimates – Impairment Assessment of Goodwill.*

We may lose executive officers or other key management personnel, which could endanger the future success of our operations.

Our success depends to a significant degree upon the continued contributions of our executive officers and other key management personnel. Our employees, including our executive officers, are employed at will and do not have employment agreements. If one or more members of our management team dies, becomes disabled or voluntarily terminates employment with us, there is no assurance that we will find a suitable or comparable substitute. We believe that our future success depends, in large part, upon our ability to hire and retain highly skilled managerial personnel. Competition for persons with these skills is intense, and we cannot assure that we will be successful in attracting and retaining such skilled personnel. The loss of any of our management personnel could adversely affect our operations.

A cyber incident could occur and result in information theft, data corruption, operational disruption, and/or financial loss.

Our business has become increasingly dependent on digital technologies to conduct day-to-day operations, including certain of our exploration, development and production activities. We depend on digital technology to estimate quantities of oil and gas reserves, process and record financial and operating data, analyze seismic and drilling information and in many other activities related to our business. Our technologies, systems and networks may become the target of cyber attacks or information security breaches that could result in the disruption of our business operations. For example, unauthorized access to our seismic data, reserves information or other proprietary information could lead to data corruption, communication interruption, or other operational disruptions in our drilling or production operations.

To date we have not experienced any material losses relating to cyber attacks, but there can be no assurance that we will not suffer such losses in the future. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any cyber vulnerabilities.

Item 1B. Unresolved Staff Comments

There are no unresolved written SEC staff comments regarding our periodic or current reports under the Securities Exchange Act of 1934 received 180 days or more before the end of the fiscal year to which this annual report on Form 10-K relates.

Item 2. Properties

Information regarding the Company's properties called for by this item is included in Item 1, *Business and Properties – Oil and Natural Gas Operations.* We also have various operating leases for rental of office space, office and field equipment, and vehicles. See Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Off-Balance Sheet Agreements,* and Note 11, *Commitments and Contingencies,* to the Consolidated Financial Statements for the future minimum rental payments. Such information is incorporated herein by reference.

Item 3. Legal Proceedings

We are involved in various lawsuits, claims and regulatory proceedings incidental to our businesses. While we currently believe that the ultimate outcome of these proceedings, individually and in the aggregate, will not have a material adverse effect on our consolidated financial position or overall trends in results of operations or cash flows, litigation is subject to inherent uncertainties. If an unfavorable ruling in one of these lawsuits or proceedings were to occur, there exists the possibility of a material adverse impact on our net income in the period in which the ruling occurs. We provide accruals for litigation and claims if we determine that we may have a range of legal exposure that would require accrual.

Item 4. Mine Safety Disclosures

Not applicable.

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

Common Stock Trading Summary

The following table summarizes the high and low reported sales prices on days in which there were trades of Denbury's common stock on the New York Stock Exchange ("NYSE") for each quarterly period for the last two fiscal years. As of January 31, 2014, based on information from the Company's transfer agent, American Stock Transfer and Trust Company, the number of holders of record of Denbury's common stock was 1,687. On February 27, 2014, the last reported sale price of Denbury's common stock, as reported on the NYSE, was $16.22 per share.

	2013		2012	
	High	Low	High	Low
First Quarter	$19.11	$16.50	$20.91	$16.29
Second Quarter	19.48	16.68	19.50	13.46
Third Quarter	18.55	16.90	17.65	13.74
Fourth Quarter	19.44	15.98	16.76	14.32

On January 28, 2014, the Board of Directors declared a dividend of $0.0625 per share on our common stock, to stockholders of record at the close of business on February 25, 2014. While we currently expect to continue to pay a regular quarterly dividend on our common stock, the declaration and payment of dividends are at the discretion of our Board of Directors and will depend on our results of operations, financial condition, capital requirements, level of indebtedness, and other factors deemed relevant by the Board of Directors. Our Bank Credit Agreement and senior subordinated note indentures require us to meet certain financial covenants at the time dividend payments are made. For further discussion, see Note 5, *Long-Term Debt,* to the Consolidated Financial Statements. Prior to 2014, we had not historically paid dividends on our common stock. No unregistered securities were sold by the Company during 2013.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

Month	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (in millions) (2)
October 2013	7,567	$18.83	—	$109.3
November 2013	18,636	19.11	—	250.0
December 2013	4,801,979	16.22	4,793,461	422.3 (3)
Total	4,828,182		4,793,461	

(1) Stock repurchases during the fourth quarter of 2013 other than those under our common stock repurchase program were made in connection with delivery by our employees of shares to us to satisfy their tax withholding requirements related to the vesting of restricted shares and the exercise of stock appreciation rights.

(2) In October 2011, the Company's Board of Directors approved a common stock repurchase program for up to $500 million of Denbury's common stock, which was increased by an additional $271.2 million in November 2012, $140.7 million in November 2013, and $250.0 million in December 2013, for a total authorization under the program of $1.162 billion. The program has no pre-established ending date and may be suspended or discontinued at any time. We are not obligated to repurchase any dollar amount or specific number of shares of our common stock under the program.

(3) Amounts shown do not give effect to the repurchase of an additional 11.8 million shares of Denbury common stock from January 1, 2014 through February 20, 2014 under the share repurchase program for $191.6 million, or $16.17 per share.

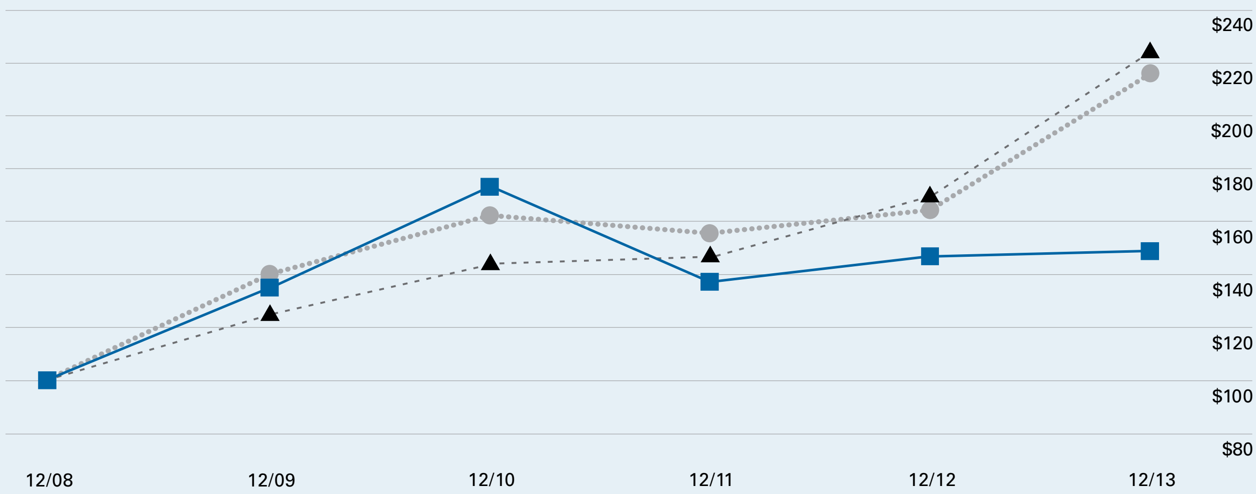
Between early October 2011, when we announced the commencement of a common share repurchase program, and December 31, 2013, we repurchased 47,559,266 shares of Denbury common stock (approximately 11.8% of our outstanding shares of common stock at September 30, 2011) for $739.7 million, or $15.55 per share.

Share Performance Graph

The following Performance Graph and related information shall not be deemed “soliciting material” or to be “filed” with the SEC, nor shall such information be incorporated by reference into any future filings under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filings.

The following graph illustrates changes over the five-year period ended December 31, 2013, in cumulative total stockholder return on our common stock as measured against the cumulative total return of the S&P 500 Index and the Dow Jones U.S. Exploration and Production Index. The graph tracks the performance of a $100 investment in our common stock and in each index (with the reinvestment of all dividends for the index securities) from December 31, 2008 to December 31, 2013.

Comparison of 5-Year Cumulative Total Return



	December 31,					
	2008	2009	2010	2011	2012	2013
Denbury Resources Inc.	$100.00	$135.53	$174.82	$138.28	$148.35	$150.46
S&P 500	100.00	126.46	145.51	148.59	172.37	228.19
Dow Jones U.S. Exploration and Production	100.00	140.56	164.09	157.22	166.37	219.35

Item 6. Selected Financial Data

In thousands, except per-share data or otherwise noted	Year Ended December 31, 2013	2012	2011	2010 [1]	2009
Consolidated Statements of Operations data:					
Revenues and other income:					
Oil, natural gas, and related product sales	$ 2,466,234	$ 2,409,867	$ 2,269,151	$1,793,292	$ 866,709
Other	50,893	46,605	40,173	128,499	22,441
Total revenues and other income	$ 2,517,127	$ 2,456,472	$ 2,309,324	$1,921,791	$ 889,150
Net income (loss) attributable to Denbury stockholders	409,597	525,360	573,333	271,723	(75,156)
Net income (loss) per common share:					
Basic	1.12	1.36	1.45	0.73	(0.30)
Diluted	1.11	1.35	1.43	0.72	(0.30)
Weighted average number of common shares outstanding:					
Basic	366,659	385,205	396,023	370,876	246,917
Diluted	369,877	388,938	400,958	376,255	246,917
Consolidated Statements of Cash Flows data:					
Cash provided by (used by):					
Operating activities	$ 1,361,195	$ 1,410,891	$ 1,204,814	$ 855,811	$ 530,599
Investing activities	(1,275,309)	(1,376,841)	(1,605,958)	(354,780)	(969,714)
Financing activities	(172,210)	45,768	37,968	(139,753)	442,637
Production (average daily):					
Oil (Bbls)	66,286	66,837	60,736	59,918	36,951
Natural gas (Mcf)	23,742	29,109	29,542	78,057	68,086
BOE (6:1)	70,243	71,689	65,660	72,927	48,299
Unit sales prices – excluding impact of derivative settlements:					
Oil (per Bbl)	$ 100.67	$ 97.18	$ 100.03	$ 75.97	$ 57.75
Natural gas (per Mcf)	3.53	3.05	4.79	4.63	3.54
Unit sales prices – including impact of derivative settlements:					
Oil (per Bbl)	$ 100.64	$ 96.77	$ 98.90	$ 71.69	$ 68.63
Natural gas (per Mcf)	3.53	5.67	7.34	6.45	3.54
Costs per BOE:					
Lease operating expenses [2]	$ 28.50	$ 20.29	$ 21.17	$ 17.67	$ 17.85
Taxes other than income	6.87	6.10	6.16	4.53	2.45
General and administrative expenses	5.66	5.49	5.24	5.04	5.77
Depletion, depreciation and amortization	19.89	19.34	17.07	16.32	13.52
Proved oil and natural gas reserves: [3]					
Oil (MBbls)	386,659	329,124	357,733	338,276	192,879
Natural gas (MMcf)	489,954	481,641	625,208	357,893	87,975
MBOE (6:1)	468,318	409,398	461,934	397,925	207,542
Proved carbon dioxide reserves:					
Gulf Coast region (MMcf) [4]	6,070,619	6,073,175	6,685,412	7,085,131	6,302,836
Rocky Mountain region (MMcf) [5]	3,272,428	3,495,534	2,195,534	2,189,756	—
Proved helium reserves associated with Denbury's production rights: [6]					
Rocky Mountain region (MMcf)	13,251	12,712	12,004	7,159	—
Consolidated Balance Sheets data:					
Total assets	$11,788,737	$11,139,342	$10,184,424	$9,065,063	$4,269,978
Total long-term liabilities	5,812,132	5,408,032	4,716,659	4,105,011	1,903,951
Stockholders' equity	5,301,406	5,114,889	4,806,498	4,380,707	1,972,237

(1) On March 9, 2010, we acquired Encore Acquisition Company ("Encore"). We consolidated Encore's results of operations beginning March 9, 2010.

(2) Lease operating expenses for the year ending December 31, 2013 include estimated costs to remediate an area of Delhi Field. Excluding these costs, lease operating expenses totaled $616.6 million and lease operating expense per BOE averaged $24.05 for the year ended December 31, 2013.

(3) Estimated proved reserves as of December 31, 2012 reflect the disposition of reserves associated with our Bakken area assets sold in late 2012 (approximately 109 MMBOE). Year-end 2012 reserves reflect CCA reserves acquired in 2010 as part of the Encore merger, but do not include then-estimated reserves of approximately 42.2 MMBOE related to the CCA Acquisition, which closed during the first quarter of 2013. See Note 2, *Acquisitions and Divestitures,* to the Consolidated Financial Statements for further discussion of these transactions.

(4) Proved CO_2 reserves in the Gulf Coast region consist of reserves from our reservoirs at Jackson Dome and are presented on a gross or 8/8ths working interest basis, of which our net revenue interest was approximately 4.8 Tcf, 4.8 Tcf, 5.3 Tcf, 5.6 Tcf and 5.0 Tcf at December 31, 2013, 2012, 2011, 2010 and 2009, respectively, and include reserves dedicated to volumetric production payments of 28.9 Bcf, 57.1 Bcf, 84.7 Bcf, 100.2 Bcf and 127.1 Bcf at December 31, 2013, 2012, 2011, 2010 and 2009, respectively. (See *Supplemental CO_2 and Helium Disclosures (Unaudited),* to the Consolidated Financial Statements.)

(5) Proved CO_2 reserves in the Rocky Mountain region consist of our reserves at Riley Ridge (presented on a gross working interest basis) and our overriding royalty interest in LaBarge Field, of which our net revenue interest was approximately 2.9 Tcf, 2.9 Tcf, 1.6 Tcf and 0.9 Tcf at December 31, 2013, 2012, 2011 and 2010, respectively.

(6) Reserves associated with helium production rights include helium reserves located in the acreage in the Rocky Mountain region for which we have the contractual right to extract the helium on behalf of the U.S. government, who owns the helium. Our extraction agreement with the U.S. government gives us the ability to produce the helium on behalf of the U.S. government in exchange for a fee, which amount fluctuates based upon the realized sales proceeds we receive for the helium. The estimate of helium reserves is reduced to reflect the estimated fee we will remit to the U.S. government. Our extraction agreement with the U.S. government has a minimum term extending 20 years from first production and continuing thereafter until either party terminates the contract. Reserve volumes presented herein assume that the term of this helium extraction agreement continues beyond 20 years, given the benefit to both parties to the agreement.

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

The following discussion and analysis should be read in conjunction with our Consolidated Financial Statements and Notes thereto included in Item 8, *Financial Statements and Supplementary Information.* Our discussion and analysis includes forward-looking information that involves risks and uncertainties and should be read in conjunction with *Risk Factors* under Item 1A of this Form 10-K, along with *Forward-Looking Information* at the end of this section for information on the risks and uncertainties that could cause our actual results to be materially different from our forward-looking statements.

OVERVIEW

Denbury is a growing, dividend-paying, domestic oil and natural gas company. Our primary focus is on enhanced oil recovery utilizing CO_2, and our operations are focused in two key operating areas: the Gulf Coast and Rocky Mountain regions. Our goal is to increase the value of acquired properties through a combination of exploitation, drilling and proven engineering extraction practices, with the most significant emphasis relating to tertiary recovery operations.

Adoption of Growth and Income Strategy. In the fourth quarter of 2013, following a comprehensive review of our long-term plans, we announced our intention to expand our shareholder value proposition to include both growth and income. Our focused strategy, significant inventory of development projects and proven track record of value creation give us confidence that we can deliver a long-term cash flow profile to stockholders that is unique among independent oil companies. To enable our shift to a growth and income company in 2014, we modified our previous development timeline for future capital projects principally in the Rocky Mountain region, making our anticipated capital spending levels more consistent over the next five to ten years. This smoothing effect on our anticipated capital expenditures allows us to accelerate our expected free cash flow. These changes reduce our capital spending on major infrastructure projects over the next few years, accelerating our plan of providing a return to our shareholders through a dividend, while still growing our oil and natural gas reserves and production at nearly the previously anticipated growth rate.

With the declaration of the first cash dividend in our history on January 28, 2014, we have begun this program of distributing free cash flow to stockholders. Our first quarterly dividend of $0.0625 per common share (a rate of $0.25 per share on an annualized basis) will be paid on March 25, 2014 to shareholders of record as of the close of business on February 25, 2014. Based on our current financial projections and commodity price outlook, we expect to grow our regular annual dividend rate to between $0.50 per share and $0.60 per share in 2015 and at a sustainable rate thereafter. All dividends are subject to declaration by Denbury's Board of Directors.

2013 Operating Highlights. Our net income was $409.6 million, or $1.11 per diluted common share, during 2013, compared to net income of $525.4 million, or $1.35 per diluted common share, during 2012. Although we had a $56.4 million increase in oil and natural gas revenues in 2013 compared to 2012 levels, driven by higher realized prices, this increase in revenues was more than offset by increases in expenses, including (1) a $198.2 million increase in lease operating expense in the current year, $114.0 million of which constitutes remediation costs incurred or estimated for an area of Delhi Field, (2) an increase of $45.9 million in commodity derivatives expense, $27.3 million of which relates to a change in the noncash fair value adjustments on our commodity derivatives, a non-GAAP measure, between the two periods and (3) a $44.7 million loss on early extinguishment of debt. These matters are further described throughout this Management's Discussion and Analysis. Our cash flow from operations was $1.4 billion in both 2013 and 2012.

During 2013, our oil and natural gas production, which was 94% oil, averaged 70,243 BOE/d, compared to 71,689 BOE/d produced during 2012. This slight decline in production was primarily due to the inclusion of 11 months of production in 2012 from the Bakken area assets sold in the Bakken Exchange Transaction (defined below), versus only nine months of production in 2013 from the purchase of additional interests in the Cedar Creek Anticline ("CCA"). This decline was offset in part by a 9% increase in our tertiary oil production. See *Results of Operations – Production* for more information.

Our average realized oil price per barrel, excluding the impact of commodity derivative contracts, was $100.67 per Bbl during 2013, or about 4% higher than our average realized oil price of $97.18 per Bbl during 2012. Our realized oil price during 2013 was $2.62 per Bbl above NYMEX oil prices compared to $2.99 per Bbl above NYMEX oil prices in 2012. The lower premium to NYMEX in 2013 is primarily due to a decline in Louisiana Light Sweet ("LLS") oil pricing relative to NYMEX prices, which LLS-to-NYMEX differential averaged a positive $11.10 in 2013 compared to positive $16.46 in 2012, partially offset by improved differentials in the Rocky Mountain region, which were positively impacted by the sale of the Bakken area assets late in 2012, which assets generally sold at a more significant discount to NYMEX than the CCA assets we acquired in early 2013. See *Results of Operations – Oil and Natural Gas Revenues* below for more information.

Cedar Creek Anticline Acquisition. On March 27, 2013, we closed our acquisition of producing assets in the CCA of Montana and North Dakota in a purchase from a wholly-owned subsidiary of ConocoPhillips Company ("ConocoPhillips") for $1.0 billion in cash, after final closing adjustments (the "CCA Acquisition"). We funded the acquisition with a portion of the cash proceeds from the late-2012 Bakken Exchange Transaction. The assets purchased include both additional interests in certain of our then-existing operated fields in CCA, as well as operating interests in other CCA fields. In conjunction with this acquisition, we added 42.2 MMBOE of estimated proved reserves.

Rocky Mountain Tertiary Operations Startup. In late 2012, we completed construction of the first section of the 20-inch Greencore Pipeline in Wyoming, our first CO_2 pipeline in the Rocky Mountain region, and received our first CO_2 deliveries from the Lost Cabin gas plant in central Wyoming during the first quarter of 2013. In December 2012, we completed the three-mile CO_2 pipeline required to deliver CO_2 from our source at LaBarge Field to Grieve Field in Wyoming, and began injecting CO_2 into Grieve Field during the first quarter of 2013. We currently expect tertiary production from Grieve Field to commence in 2015. We started injections at our Bell Creek Field in Montana during the second quarter of 2013, with the first tertiary oil production from this field during the third quarter of 2013. During the first quarter of 2014, we completed the pipeline interconnect between a third party's existing CO_2 pipeline and our Greencore pipeline, which will allow us to transport additional volumes of CO_2 to Bell Creek Field.

Riley Ridge Plant. During the fourth quarter of 2013, we placed our Riley Ridge gas processing facility in Wyoming into service.

Proved Oil and Natural Gas Reserves. Our estimated proved oil and gas reserves were 468.3 MMBOE as of December 31, 2013, compared to 409.4 MMBOE at December 31, 2012. We added total proved reserves of 84.6 MMBOE during 2013, including estimated proved tertiary reserves of 34.0 MMBbls at Bell Creek Field during the fourth quarter, 42.2 MMBOE from the acquisition of additional interests in CCA during the first quarter and 8.4 MMBOE of other additions or revisions.

Addition of Proved CO_2 Reserves. During the year ended December 31, 2013, we added approximately 350 Bcf of estimated proved CO_2 reserves as a result of successful drilling in the Jackson Dome area, our primary source of CO_2 for the Gulf Coast region, replacing our 2013 CO_2 production.

Debt Refinancing. In February 2013, we issued $1.2 billion of 4⅝% Senior Subordinated Notes due 2023 (the "2023 Notes"). The net proceeds of approximately $1.18 billion were used to repurchase or redeem our 9½% Senior Subordinated Notes due 2016 (the "9½% Notes") and our 9¾% Senior Subordinated Notes due 2016 (the "9¾% Notes"), and to pay down a portion of outstanding borrowings on our bank credit facility. We recognized a loss associated with the redemption of our 9½% Notes and 9¾% Notes of $44.7 million during the year ended December 31, 2013, which is included in our Consolidated Statement of Operations under the caption "Loss on early extinguishment of debt". See Note 5, *Long-Term Debt,* to the Consolidated Financial Statements for additional details surrounding the repurchase and redemption of our 9½% Notes and 9¾% Notes.

Delhi Field Release. In June 2013, a release of well fluids, consisting of a mixture of carbon dioxide, saltwater, natural gas and oil, was discovered and reported within an area of the Denbury-operated Delhi Field located in northern Louisiana. Denbury immediately took remedial action to stop the release and contain and recover well fluids in the affected area. We have determined that the release originated from one or more wells in the affected area of the field that we believed had been previously and properly plugged and abandoned by a prior operator of the field. We completed our remediation efforts during the fourth quarter of 2013; however, we will continue to monitor the area to ensure the remediation efforts were successful.

During the year ended December 31, 2013, we recorded $114.0 million of lease operating expenses related to this release in our Consolidated Statement of Operations. These expenses represent our current estimate of the costs related to the release, including remediation costs, based on actual costs incurred through December 31, 2013 of approximately $92.0 million, plus the Company's estimate of future costs related to the satisfaction of known claims and liabilities. Due to the possibility of new claims being asserted in the future in connection with the release, as well as variability in the estimated cost to continue to monitor the area to ensure the remediation efforts were successful, we cannot reliably determine at this time the full extent of the costs that may ultimately be incurred by the Company related to this release. Although the Company maintains insurance policies that we believe cover certain of the costs, damages and claims related to the release, and we currently and preliminarily estimate that one-third to two-thirds of our current cost estimate may be recoverable under such insurance policies, we have not reached any agreement with our insurance carriers as to recoverable amounts, and accordingly have not recognized any insurance recoveries in our financial statements as of December 31, 2013. See Note 11, *Commitments and Contingencies,* to the Consolidated Financial Statements for further discussion.

Costs incurred as a result of the release, together with lower production levels during the second half of 2013, are currently expected to delay into 2014 the effective date of the approximate 25% reversionary interest to the third party that sold the Delhi Field interest to us, the specific timing of which is dependent upon, among other things, the amount and timing of any potential insurance proceeds received and their application to the calculation of "total net cash flow" which determines the reversionary date, as well as oil prices, production, and production costs. We currently estimate that the reversionary date could occur as late as the fourth quarter of 2014.

Bakken Exchange Transaction. In late 2012, we closed a sale and exchange transaction with Exxon Mobil Corporation and its wholly-owned subsidiary XTO Energy Inc. (collectively, "ExxonMobil") under which we sold to ExxonMobil our Bakken area assets in North Dakota and Montana in exchange for (1) $1.3 billion in cash, (2) operating interests in Hartzog Draw and Webster fields in Wyoming and Texas, respectively, and (3) an overriding royalty interest equivalent to an approximate one-third ownership interest in ExxonMobil's CO_2 reserves in LaBarge Field in Wyoming (the "Bakken Exchange Transaction"). The magnitude of the Bakken Exchange Transaction and the CCA Acquisition discussed above impact the comparability of our 2012 and 2013 financial results in many ways, including oil and natural gas production, revenues, and operating expenses. Our financial results for the year ended December 31, 2013 include the results from the CCA Acquisition beginning late in the first quarter of 2013.

CAPITAL RESOURCES AND LIQUIDITY

Overview. Our primary sources of capital and liquidity are our cash flows from operations and borrowings under our bank credit facility. Our business is capital intensive, and it is common for oil and natural gas companies our size to reinvest most or all of their cash flow into developing new assets. We generally attempt to balance our capital spending with cash flow from operations, and we have repurchased 59.4 million shares of our common stock (approximately 14.8% of our outstanding shares at September 30, 2011) since commencement of our share repurchase program in October 2011 through February 20, 2014. During 2013, we purchased $277.8 million of our common stock, which was funded with a combination of cash flow from operations and incremental borrowings. In early 2013, we refinanced two of our high-rate subordinated notes with ten-year notes carrying an interest rate of 4⅝%, lowering our interest expense and reducing our outstanding bank borrowings with a portion of the proceeds. We project that we will have more than adequate capital resources and liquidity for the foreseeable future because (1) we have refinanced our bank debt with low-cost subordinated debt, leaving significant borrowing capacity on our bank line; (2) we have oil hedges in place for a substantial portion of our forecasted proven oil production for the next two years, including fixed price swap derivative contracts for 2014 (see Note 9, *Commodity Derivative Contracts,* to the Consolidated Financial Statements for further details regarding the prices and volumes of our commodity derivative contracts); (3) we expect to fund our projected capital expenditures for the next few years with cash flow from operations, which means that our expected growth in production and cash flow will gradually reduce our leverage (assuming oil prices are relatively consistent with current levels); (4) we expect to fund our planned dividends with cash flow from operations, (5) depending on the amount of shares of our common stock we repurchase in 2014, we might defer a portion of our planned 2014 capital expenditures, and (6) we can significantly reduce our capital expenditures for extended periods of time if necessary and still maintain current production levels as a result of our unique EOR operations.

2014 Capital Spending. We anticipate that our 2014 capital budget, excluding acquisitions, will be $1.0 billion, plus approximately $125 million in capitalized internal acquisition, exploration and development costs; capitalized interest; and pre-production costs associated with new tertiary floods. This combined 2014 capital budget amount of $1.125 billion, excluding acquisitions, is comprised of the following:

- $680 million allocated for tertiary oil field expenditures;
- $220 million allocated for other areas, primarily non-tertiary oil field expenditures;
- $60 million for pipeline construction;
- $40 million to be spent on CO_2 sources; and
- $125 million for other capital items such as capitalized internal acquisition, exploration and development costs; capitalized interest; and pre-production start-up costs associated with new tertiary floods.

Based on oil and natural gas commodity futures prices in early February 2014, our current production forecast, and our fixed-price swaps covering a substantial portion of our anticipated 2014 production, we believe our anticipated 2014 cash flow from operations should be adequate to cover our combined 2014 capital budget and planned dividend payments. If prices were to decrease or changes in operating results were to cause us to have a significant reduction in anticipated 2014 cash flows, we have ample availability on our bank credit facility to cover any potential shortfall, and we also have the ability to reduce our capital expenditures.

If we reduce our capital spending due to lower cash flows or to fund share repurchases, any sizeable reduction could lower our anticipated production levels in future years. For 2014 and some future years, we have contracted for certain capital expenditures; therefore, we cannot eliminate all of our capital commitments without penalties (see *Commitments and Obligations* for further information regarding these commitments).

Stock Repurchase Program. Our Board of Directors has approved a common share repurchase program for up to $1.162 billion of Denbury common stock. As of February 20, 2014, we had spent $931.2 million to repurchase 59.4 million shares of our common stock under this program. Our share repurchases are based on various parameters and, therefore, may be less than the remaining approved balance under the program, for which there is no set expiration date. We anticipate that repurchases during 2014 will be primarily funded with excess cash flow from operations or with borrowings under our bank credit facility or a reduction in capital spend. See Note 7, *Stockholders' Equity,* to the Consolidated Financial Statements for further discussion.

Bank Credit Facility. We have a $1.6 billion bank credit facility that is secured by substantially all of our oil and natural gas properties. As part of our semiannual bank review in late October 2013, the borrowing base for our bank credit facility was reaffirmed at $1.6 billion. Our next borrowing base redetermination is scheduled on or around May 1, 2014. We currently do not anticipate any reduction in our borrowing base as part of that redetermination, and we believe, based on current commodity prices and our proved reserves, that we could obtain lender approval to significantly increase the borrowing base under our bank credit facility above the current $1.6 billion level if we desired to do so. As of February 21, 2014, we had $645.0 million outstanding under our $1.6 billion bank credit facility and estimated cash of approximately $85.4 million, leaving us significant liquidity to fund capital expenditures and future dividends.

2014 Commencement of Payment of Dividends. On January 28, 2014, our Board of Directors declared a dividend of $0.0625 per share on our common stock, to stockholders of record at the close of business on February 25, 2014. We expect this dividend payment to be approximately $22 million and to be paid on March 25, 2014. The declaration and payment of future dividends is at the discretion of our Board of Directors, and the amount thereof will depend on our results of operations, financial condition, capital requirements, level of indebtedness, and other factors deemed relevant by the Board of Directors.

Capital Expenditure Summary. The following table summarizes our 2013 capital expenditures by project area. Amounts include accrued capital expenditures:

	Year Ended December 31,		
In thousands	2013	2012	2011
Capital expenditures by project			
Tertiary oil fields	$ 534,878	$ 449,226	$ 487,383
Non-tertiary fields	224,556	543,162	558,545
Capitalized interest and internal costs (1)	114,197	93,663	105,849
Oil and natural gas capital expenditures	873,631	1,086,051	1,151,777
CO_2 pipelines	57,136	181,873	163,464
CO_2 sources (2)	163,710	238,613	158,303
CO_2 capitalized interest and other	49,021	47,628	27,181
Capital expenditures before acquisitions	1,143,498	1,554,165	1,500,725
Less: recoveries from sale/leaseback transactions	—	(35,102)	(70,332)
Net capital expenditures excluding acquisitions	1,143,498	1,519,063	1,430,393
Property acquisitions (3)	1,032,218	942,359	250,084
Capital expenditures, net of sale/leaseback transactions	$2,175,716	$2,461,422	$1,680,477

(1) Includes capitalized internal acquisition, exploration and development costs; capitalized interest; and pre-production start-up costs associated with new tertiary floods.

(2) Includes capital expenditures related to the Riley Ridge gas processing facility.

(3) Property acquisitions during the years ended December 31, 2013 and 2012 include capital expenditures of approximately $1.0 billion and $0.2 billion, respectively, related to acquisitions during the period that are not reflected as an Investing Activity on our Consolidated Statements of Cash Flows due to the movement of proceeds through a qualified intermediary to facilitate like-kind-exchange treatment under federal income tax rules. In addition, property acquisitions in 2012 shown above include capital expenditures of approximately $0.6 billion representing the aggregate fair value of net assets acquired, excluding cash, in the Bakken Exchange Transaction. See Note 2, *Acquisitions and Divestitures,* to the Consolidated Financial Statements.

Our 2013 capital expenditures, other than those for property acquisitions, were funded with $1.4 billion of cash flow from operations, and those for property acquisitions were funded with proceeds from the Bakken Exchange Transaction. Our 2012 capital expenditures were funded primarily with $1.4 billion of cash flow from operations, and our property acquisitions were funded with proceeds from the sale of non-core assets and the Bakken Exchange Transaction. Our 2011 capital expenditures, excluding the Riley Ridge acquisition, were funded with $1.2 billion of cash flow from operations and cash on hand at the beginning of the period. The Riley Ridge acquisition was funded with incremental bank debt.

Commitments and Obligations. A summary of our obligations at December 31, 2013 is presented in the following table:

In thousands	Payments Due by Period 2014	2015 and 2016	2017 and 2018	Thereafter	Total
Contractual obligations:					
Bank Credit Agreement	$ —	$ 340,000	$ —	$ —	$ 340,000
Estimated interest payments on bank credit facility and subordinated debt	174,491	341,514	326,535	411,467	1,254,007
Subordinated debt	1,072	485	2,250	2,596,273	2,600,080
Operating lease obligations	11,695	25,052	25,504	67,832	130,083
Pipeline and capital lease obligations	62,929	123,073	106,159	280,272	572,433
Other obligations (1)	168,938	220,139	193,609	750,835	1,333,521
Commodity derivative liabilities (2)	53,822	3,413	—	—	57,235
Asset retirement obligations (3)	5,307	2,933	107	493,880	502,227
Total contractual obligations	$478,254	$1,056,609	$654,164	$4,600,559	$6,789,586

(1) Represents future cash commitments under contracts in place as of December 31, 2013, primarily for pipe, anthropogenic CO_2 purchase contracts, drilling rig services and well-related costs. As is common in our industry, we commit to make certain expenditures on a regular basis as part of our ongoing development and exploration program. These commitments generally relate to projects that occur during the subsequent several months and are usually part of our normal operating expenses or part of our capital budget (see *2014 Capital Spending* above). In certain cases we have the ability to terminate contracts for equipment or supplies, in which case we would be liable only for the cost incurred by the vendor up to that point; however, as we currently do not anticipate canceling those contracts, these amounts include our estimated payments under those contracts. We also have recurring expenditures for such things as accounting, engineering and legal fees; software maintenance; subscriptions; and other overhead-type items. Normally these expenditures do not change materially on an aggregate basis from year to year and are part of our general and administrative expenses. We have not attempted to estimate the amounts of these types of recurring expenditures in this table, as most could be quickly canceled with regard to any specific vendor, even though the expense itself may be required for our ongoing normal operations. Other obligations exclude approximately $980 million of potential costs for periods after 2017 to buy anthropogenic CO_2 in accordance with purchase contracts under which we may not become obligated, as construction of the plants which may emit CO_2 has not yet begun.

(2) Commodity derivative liabilities represent the fair value of our commodity derivatives presented as liabilities in our Consolidated Balance Sheet as of December 31, 2013. The ultimate settlement amounts of our derivative obligations are unknown because they are subject to continuing market fluctuations. See further discussion of our commodity derivative contracts and their market price sensitivities in *Market Risk Management* below in this *Management's Discussion and Analysis of Financial Condition and Results of Operations,* and in Note 9, *Commodity Derivative Contracts,* to the Consolidated Financial Statements.

(3) Represents the estimated future asset retirement obligations on an undiscounted basis. The present value of the discounted asset retirement obligation is $126.3 million, as determined under the Asset Retirement and Environmental Obligations topic of the FASC, and is further discussed in Note 3, *Asset Retirement Obligations,* to the Consolidated Financial Statements.

Off-Balance Sheet Arrangements. We have several operating leases relating to office space and other minor equipment leases. At December 31, 2013, we had a total of $11.7 million of letters of credit outstanding under our bank credit facility. Additionally, we have obligations that are not currently recorded on our balance sheet relating to various obligations for development and exploratory expenditures that arise from our normal capital expenditure program or from other transactions common to our industry. These obligations are further described in *Commitments and Obligations* above. In addition, in order to recover our undeveloped proved reserves, we must also fund the associated future development costs estimated in our proved reserve reports. For a further discussion of our future development costs, see *Supplemental Oil and Natural Gas Disclosures (Unaudited),* to the Consolidated Financial Statements.

FINANCIAL OVERVIEW OF TERTIARY OPERATIONS

As discussed in Item 1, *Business and Properties – Oil and Natural Gas Operations – Enhanced Oil Recovery Overview* above, our tertiary operations represent a significant portion of our overall operations and have become our primary strategic focus. The economics of a tertiary field and the related impact on our financial statements differ from a conventional oil and gas play and are explained further below.

While it is difficult to accurately forecast future production, we believe our tertiary recovery operations provide significant long-term production growth potential at reasonable rates of return, with relatively low risk. Our rate of return from our tertiary operations has generally been higher than our rate of return on traditional oil and gas operations. Generally, finding and development costs are lower and operating costs are higher than traditional oil and gas operations. We have been developing tertiary oil properties for over 14 years, and the financial impact of such operations is reflected in our historical financial statements. The summary below highlights our observations regarding how tertiary operations have impacted our financial statements.

Finding and Development Costs. We currently expect finding and development costs (including future development and abandonment costs but excluding CO_2 pipeline infrastructure capital expenditures) over the life of each field to be lower than the industry average costs for other oil properties. See the definition of finding and development costs in the *Glossary and Selected Abbreviations.*

Timing of Capital Costs. There is a significant delay between the initial capital expenditures on tertiary oil fields and the resulting production increases. We must build facilities, and often a CO_2 pipeline to the field, before CO_2 flooding can commence, and it usually takes six to twelve months before the field responds to the injection of CO_2 (i.e., oil production commences). Further, we may spend significant amounts of capital before we can recognize any proved reserves from fields we flood and, even after a field has proved reserves, significant amounts of additional capital will usually be required to fully develop the field.

Recognition of Proved Reserves. In order to recognize proved tertiary oil reserves, we must either demonstrate production resulting from the tertiary process or the field must be analogous to an existing tertiary flood. The magnitude of proved reserves that we can book in any given year will depend on our progress with new floods, the timing of the production response from new floods and the performance of our existing floods. Typically, a high percentage of the potential reserves for a tertiary field are recognized when a production response is initially observed, and generally only modest increases are made thereafter.

Production Rates. The production growth rate at a tertiary flood can vary from quarter to quarter, as a tertiary field's production may increase rapidly when wells respond to the CO_2, plateau temporarily, and then resume growth as additional areas of the field are developed. During a tertiary flood life cycle, facility capacity is increased from time to time, which occasionally requires temporary shutdowns during installation, thereby causing temporary declines in production. We also find it difficult to precisely predict when any given well will respond to the injected CO_2, as the CO_2 seldom travels through the rock consistently due to heterogeneity in the oil-bearing formations. We find all of these fluctuations to be normal, and generally expect oil production at a tertiary field to increase over time until the entire field is developed, albeit sometimes in inconsistent patterns.

Operating Costs. Tertiary projects may be more expensive to operate than traditional industry operations because of the cost of injecting and recycling the CO_2 (primarily due to the cost of the CO_2 and the significant energy requirements to re-compress the CO_2 back into a near-liquid state for re-injection purposes). The costs of our CO_2 and the electricity required to recycle and inject this CO_2 comprise almost half of our typical tertiary operating expenses. Since these costs vary along with commodity and commercial electricity prices, they are highly variable and will increase in a high-commodity-price environment and decrease in a low-price environment. Most of our CO_2 operating costs are allocated to our tertiary oil fields and recorded as lease operating expenses (following the commencement of tertiary oil production) at the time the CO_2 is injected. These costs have historically represented approximately 20% to 25% of the total operating costs for our tertiary operations. Since we expense all of the operating costs to produce and inject our CO_2 (following the commencement of tertiary oil production), operating costs per barrel for a new flood will be higher at the inception of CO_2 injection projects because of minimal related oil production at that time.

RESULTS OF OPERATIONS

Operating Results Table

Certain of our operating results and statistics for each of the last three years are included in the following table.

In thousands, except per share and unit data	Year Ended December 31, 2013	2012	2011
Operating results			
Net income	$ 409,597	$ 525,360	$ 573,333
Net income per common share – basic	1.12	1.36	1.45
Net income per common share – diluted	1.11	1.35	1.43
Net cash provided by operating activities	1,361,195	1,410,891	1,204,814
Average daily production volumes			
Bbls/d	66,286	66,837	60,736
Mcf/d	23,742	29,109	29,542
BOE/d	70,243	71,689	65,660
Operating revenues			
Oil sales	$2,435,625	$2,377,337	$2,217,529
Natural gas sales	30,609	32,530	51,622
Total oil and natural gas sales	$2,466,234	$2,409,867	$2,269,151
Commodity derivative contracts (1)			
Cash receipt (payment) on settlements of commodity derivatives	$ (662)	$ 17,880	$ 2,377
Noncash fair value adjustments on commodity derivatives (2)	(40,362)	(13,046)	50,120
Commodity derivatives income (expense)	$ (41,024)	$ 4,834	$ 52,497
Unit prices – excluding impact of derivative settlements			
Oil price per Bbl	$ 100.67	$ 97.18	$ 100.03
Natural gas price per Mcf	3.53	3.05	4.79
Unit prices – including impact of derivative settlements (1)			
Oil price per Bbl	$ 100.64	$ 96.77	$ 98.90
Natural gas price per Mcf	3.53	5.67	7.34
Oil and natural gas operating expenses			
Lease operating expenses (3)	$ 730,574	$ 532,359	$ 507,397
Marketing expenses, net of third-party purchases	37,754	41,936	26,047
Production and ad valorem taxes	162,791	149,919	139,170
Oil and natural gas operating revenues and expenses per BOE			
Oil and natural gas revenues	$ 96.19	$ 91.85	$ 94.68
Lease operating expenses (3)	28.50	20.29	21.17
Marketing expenses, net of third-party purchases	1.47	1.60	1.09
Production and ad valorem taxes	6.35	5.71	5.81
CO_2 sources – revenues and expenses			
CO_2 sales and transportation fees	$ 27,950	$ 26,453	$ 22,711
CO_2 discovery and operating expenses (4)	(16,916)	(14,694)	(14,258)
CO_2 revenue and expenses, net	$ 11,034	$ 11,759	$ 8,453

(1) See also *Market Risk Management* below for information concerning our commodity derivative transactions.

(2) Noncash fair value adjustments on commodity derivatives is a non-GAAP measure and is different from “Commodity derivatives expense (income)” in the Consolidated Statements of Operations in that the noncash fair value adjustments on commodity derivatives represents only the net change between periods of the fair market values of commodity derivative positions, and excludes the impact of cash settlements on commodity derivatives during the period, which were cash receipts (payments) on settlements of $(0.7) million, $17.9 million and $2.4 million for the years ended December 31, 2013, 2012 and 2011, respectively. We believe that noncash fair value adjustments on commodity derivatives is a useful supplemental disclosure to “Commodity derivatives expense (income)” in order to differentiate noncash fair market value adjustments from cash settlements on commodity derivatives during the period. This supplemental disclosure is widely used within the industry and by securities analysts, banks and credit rating agencies in calculating EBITDA and in adjusting net income to present those measures on a comparative basis across companies, as well as to assess compliance with certain debt covenants. Noncash fair value adjustments on commodity derivatives is not a measure of financial or operating performance under GAAP, nor should it be considered in isolation or as a substitute for “Commodity derivatives expense (income)” in the Consolidated Statements of Operations. See also the *Glossary and Selected Abbreviations* for the definition of noncash fair value adjustments on commodity derivatives.

(3) Excluding estimated lease operating expenses recorded during 2013 to remediate an area of Delhi Field, lease operating expenses totaled $616.6 million and lease operating expense per BOE averaged $24.05 for the year ended December 31, 2013.

(4) Includes $0.8 million, $9.5 million, and $7.5 million of exploratory costs incurred in 2013, 2012 and 2011, respectively.

Production

Average daily production by area for 2013, 2012 and 2011, and for each of the quarters of 2013, is shown below:

	Average Daily Production (BOE/d)						
	2013 Quarters				Year Ended December 31,		
Operating Area	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	2013	2012	2011
Tertiary oil production							
Gulf Coast region							
Mature properties:							
Brookhaven	2,305	2,339	2,224	2,026	2,223	2,692	3,255
Eucutta	2,636	2,642	2,504	2,280	2,514	2,868	3,121
Mallalieu	2,116	2,157	2,042	1,886	2,050	2,338	2,693
Other mature properties (1)	7,800	7,233	6,761	6,287	7,016	7,707	8,955
Total mature properties	14,857	14,371	13,531	12,479	13,803	15,605	18,024
Delhi	5,827	5,479	4,517	4,793	5,149	4,315	2,739
Hastings	3,956	4,010	3,699	4,270	3,984	2,188	—
Heidelberg	3,943	4,149	4,553	5,206	4,466	3,763	3,448
Oyster Bayou	2,252	2,518	3,213	3,869	2,968	1,388	5
Tinsley	8,222	8,225	7,951	7,809	8,051	7,947	6,743
Total Gulf Coast region	39,057	38,752	37,464	38,426	38,421	35,206	30,959
Rocky Mountain region							
Bell Creek	—	—	49	177	56	—	—
Total Rocky Mountain region	—	—	49	177	56	—	—
Total tertiary oil production	39,057	38,752	37,513	38,603	38,477	35,206	30,959
Non-tertiary oil and gas production							
Gulf Coast region							
Mississippi	3,013	2,367	2,692	2,711	2,695	3,930	5,486
Texas	6,692	6,932	6,548	5,994	6,540	4,737	4,133
Other	1,153	1,108	1,087	1,041	1,097	1,235	1,336
Total Gulf Coast region	10,858	10,407	10,327	9,746	10,332	9,902	10,955
Rocky Mountain region							
Cedar Creek Anticline (2)	8,745	19,935	18,872	18,601	16,572	8,503	8,968
Other	5,163	4,958	4,819	4,516	4,862	3,231	2,968
Total Rocky Mountain region	13,908	24,893	23,691	23,117	21,434	11,734	11,936
Total non-tertiary production	24,766	35,300	34,018	32,863	31,766	21,636	22,891
Total continuing production	63,823	74,052	71,531	71,466	70,243	56,842	53,850
Properties disposed:							
Bakken area assets (3)	—	—	—	—	—	14,395	9,340
Non-core asset divestitures (4)	—	—	—	—	—	452	2,470
Total production	63,823	74,052	71,531	71,466	70,243	71,689	65,660

(1) Other mature properties include Cranfield, Little Creek, Lockhart Crossing, Martinville, McComb and Soso fields.

(2) Beginning March 27, 2013, amounts include production from our purchase of additional interests in the CCA on that date.

(3) Includes production from certain Bakken area assets sold in the fourth quarter of 2012.

(4) Includes production from certain non-core Gulf Coast assets sold in late February 2012 and certain non-operated assets in the Greater Aneth Field in the Paradox Basin of Utah sold in April 2012.

Total Production

We closed on our Bakken Exchange Transaction late in 2012 and utilized the proceeds from that transaction to purchase additional interests in CCA in late March 2013. Accordingly, total production decreased 1,446 BOE/d (2%) between 2012 and 2013, primarily due to the inclusion in 2012 of 11 months of production from our Bakken area assets, compared to the inclusion of only nine months of additional CCA production in our 2013 results. This decline in production due to timing of transactions was partially offset by a 9% increase in tertiary production.

Total production increased 6,029 BOE/d (9%) between 2011 and 2012. The increases were primarily due to production increases from our tertiary oil fields and increases from our Bakken area assets (which were sold late in the fourth quarter of 2012), offset by normal declines in most of our other non-tertiary properties.

Our production during 2013 was 94% oil compared to 93% for 2012 and 2011. The slight increase in oil production percentage in 2013 is due to increases in our tertiary production, which is primarily oil, as well as the sale of our Bakken area assets, which had a higher percentage of natural gas production than the CCA assets acquired.

Tertiary Production

Oil production from our tertiary operations increased to record levels during 2013, averaging 38,477 Bbls/d, a 9% increase over our 2012 tertiary production level of 35,206 Bbls/d, primarily due to production growth in response to continued field development and expansion of facilities in our tertiary floods at Delhi, Hastings, Heidelberg and Oyster Bayou fields. Offsetting these 2013 production gains were production declines in our more mature tertiary fields. Tertiary production during the fourth quarter of 2013 increased 3% over third-quarter levels, largely due to continued production growth at Heidelberg and Oyster Bayou fields, the completion of planned maintenance activities at Hastings Field, and increased CO_2 injections into areas surrounding the impacted area of Delhi Field (see *Overview – Delhi Field Release* and Note 11, *Commitments and Contingencies,* to the Consolidated Financial Statements for further discussion of this matter). We started injections at our Bell Creek Field in Montana during the second quarter of 2013, with the first tertiary oil production from this field during the third quarter of 2013. The ramp up of production at Bell Creek Field has been slower than anticipated due to the delayed completion of a CO_2 pipeline interconnect originally scheduled for the fourth quarter of 2013 and the interruptions in CO_2 delivery from the Lost Cabin gas plant. With the completion of the pipeline interconnect during the first quarter of 2014, we have increased CO_2 injections at Bell Creek Field and expect production at the field to increase at a faster pace during 2014.

Oil production from our tertiary operations averaged 35,206 Bbls/d during 2012, a 14% increase over our 2011 tertiary production level of 30,959 Bbls/d, primarily due to production growth in response to continued expansion of the tertiary floods at Tinsley and Delhi fields and production at our Oyster Bayou and Hastings fields, which experienced their initial tertiary production response in late December 2011 and early January 2012, respectively. Offsetting 2012 tertiary production gains were declines in our more mature tertiary fields.

Non-Tertiary Production

Continuing production from our non-tertiary operations, which excludes production from our Bakken and other non-core assets divested during 2012, increased to an average of 31,766 BOE/d during 2013, an increase of 10,130 BOE/d (47%) compared to 2012 continuing production levels. The non-tertiary continuing production increases were primarily due to production from newly acquired fields, specifically the additional interests in CCA acquired in March 2013, Webster and Hartzog Draw fields acquired in the Bakken Exchange Transaction in late 2012, and Thompson Field acquired in June 2012. With the exception of the impact of the production added from fields acquired during 2012 and 2013, production from our other non-tertiary properties is generally on decline, and in some instances the decline is pronounced due to the expansion of our tertiary floods, which causes non-tertiary production to be shut in for a period while the field is being pressured up. Continuing production from our non-tertiary operations during the fourth quarter of 2013 decreased 3% from third-quarter levels, partially due to severe weather-related issues during the fourth quarter. Continuing production from our non-tertiary operations decreased 5% from 2011 to 2012, due primarily to non-tertiary oil production declines as a result of the expansion of our tertiary floods in those areas. These declines were partially offset by production from acquisitions during 2012, which increased our production in Texas.

Oil and Natural Gas Revenues

Oil and natural gas revenues increased in each of the past two years. The increase in oil and natural gas revenues in 2013 was the result of increases in commodity prices, slightly offset by a small decline in production, whereas the increase in oil and natural gas revenues in 2012 was attributable to higher production volumes, slightly offset by a decline in commodity prices. The changes in revenues due to these factors, excluding any impact of our commodity derivative contracts, are reflected in the following table:

	Year Ended December 31, 2013 vs. 2012		Year Ended December 31, 2012 vs. 2011	
In thousands	Increase (Decrease) in Revenues	Percentage Increase (Decrease) in Revenues	Increase (Decrease) in Revenues	Percentage Increase (Decrease) in Revenues
Change in revenues due to:				
Increase (decrease) in production	$(55,065)	(2)%	$215,150	9%
Increase (decrease) in commodity prices	111,432	4%	(74,434)	(3)%
Total increase in oil and natural gas revenues	$ 56,367	2%	$140,716	6%

Excluding any impact of our commodity derivative contracts, our net realized commodity prices and NYMEX differentials were as follows during 2013, 2012 and 2011:

	Year Ended December 31,		
	2013	2012	2011
Net realized prices:			
Oil price per Bbl	$100.67	$ 97.18	$100.03
Natural gas price per Mcf	3.53	3.05	4.79
Price per BOE	96.19	91.85	94.68
NYMEX differentials:			
Oil per Bbl	$ 2.62	$ 2.99	$ 4.95
Natural gas per Mcf	(0.19)	0.23	0.76

As reflected in the table above, our average net realized oil price increased 4% during 2013 compared to the average price received during 2012. Company-wide average oil price differentials were $2.62 per Bbl above NYMEX in 2013, compared to an average differential of $2.99 per Bbl above NYMEX in 2012 and $4.95 per Bbl above NYMEX in 2011. During 2013, we sold approximately 46% of our crude oil at prices based on the LLS index price, approximately 23% at prices partially tied to the LLS index price, and the balance at prices based on various other indexes tied to NYMEX prices, primarily in the Rocky Mountain region. The net differential we received was primarily impacted by positive differentials in the Gulf Coast region, offset by unfavorable differentials in the Rocky Mountain region, each of which is discussed in further detail below.

We received favorable NYMEX differentials in the Gulf Coast region during 2013, 2012 and 2011, primarily due to the favorable differential for crude oil sold under LLS index prices. During 2013, the quarterly average LLS-to-NYMEX differential (on a trade-month basis) decreased in each quarter of 2013, from the first quarter average of $20.15 per Bbl to $2.58 per Bbl in the fourth quarter. In 2012 and 2011, the quarterly average LLS-to-NYMEX differential (on a trade-month basis) ranged from a positive $9.28 per Bbl to $23.36 per Bbl.

NYMEX oil differentials in the Rocky Mountain region during 2013 were $8.10 per Bbl below NYMEX compared to an average differential of $11.86 per Bbl below NYMEX in 2012. The change in the differential between 2012 and 2013 was largely impacted by the sale of our Bakken area assets in the fourth quarter of 2012, since oil from the Bakken area assets generally sold at a higher discount to NYMEX than the CCA production acquired in early 2013.

Prices received in a regional market fluctuate frequently and can differ from NYMEX pricing due to a variety of reasons, including supply and/or demand factors and location differentials. During the fourth quarter of 2013, we observed a decline in the favorable LLS-to-NYMEX differential and a widening of the Rocky Mountain differential, causing our overall NYMEX oil differential to be a negative $4.57 per Bbl in the fourth quarter of 2013. This quarterly negative differential is the widest we have experienced in several years. Although we have seen the LLS and Rocky Mountain differentials improve somewhat in early 2014, we do not expect the LLS-to-NYMEX differential to return to more favorable levels we have experienced during the last few years due to the oil transportation capacity that has been added, which allows more oil production access to the LLS market.

Our natural gas NYMEX differentials are generally caused by movement in the NYMEX natural gas prices during the month, as most of our natural gas is sold on an index price that is set near the first of each month. While the percentage change in NYMEX natural gas differentials can be quite large, these differentials are very seldom more than a dollar above or below NYMEX prices.

Commodity Derivative Contracts

From time to time, we enter into oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production. These contracts have consisted of price floors, collars and fixed price swaps. The following table summarizes the impact our oil and natural gas derivative contracts had on our operating results for 2013, 2012 and 2011:

	Non-Cash Fair Value Gain/(Loss) (1)			Cash Settlements Receipt/(Payment)		
In thousands	2013	2012	2011	2013	2012	2011
Crude oil derivative contracts:						
First quarter	$(11,929)	$(42,445)	$(167,064)	$ —	$(8,230)	$ (5,028)
Second quarter	45,501	140,923	187,194	—	(709)	(16,972)
Third quarter	(79,784)	(60,726)	205,355	(662)	(641)	(1,857)
Fourth quarter	5,854	(26,848)	(166,505)	—	(411)	(1,271)
Full Year	$(40,358)	$ 10,904	$ 58,980	$(662)	$(9,991)	$(25,128)
Natural gas derivative contracts:						
First quarter	$ —	$ (1,640)	$ (5,274)	$ —	$ 7,040	$ 6,616
Second quarter	—	(9,096)	(3,348)	—	7,991	6,030
Third quarter	—	(7,174)	229	—	6,910	6,427
Fourth quarter	(4)	(6,040)	(467)	—	5,930	8,432
Full Year	$ (4)	$(23,950)	$ (8,860)	$ —	$27,871	$ 27,505
Total commodity derivative contracts:						
First quarter	$(11,929)	$(44,085)	$(172,338)	$ —	$(1,190)	$ 1,588
Second quarter	45,501	131,827	183,846	—	7,282	(10,942)
Third quarter	(79,784)	(67,900)	205,584	(662)	6,269	4,570
Fourth quarter	5,850	(32,888)	(166,972)	—	5,519	7,161
Full Year	$(40,362)	$(13,046)	$ 50,120	$(662)	$17,880	$ 2,377

(1) Noncash fair value adjustments on commodity derivatives is a non-GAAP measure. A reconciliation of noncash fair value adjustments on commodity derivatives to "Commodity derivatives expense (income)" is included in the *Operating Results Table* above. See also the *Glossary and Selected Abbreviations* for the definition of noncash fair value adjustments on commodity derivatives.

Changes in commodity prices and the expiration of contracts cause fluctuations in the estimated fair value of our oil and natural gas derivative contracts. Because we do not utilize hedge accounting for our commodity derivative contracts, the period-to-period changes in the fair value of these contracts, as outlined above, are recognized in our statements of operations. The detail of our outstanding commodity derivative contracts at December 31, 2013 is included in Note 9, *Commodity Derivative Contracts,* to the Consolidated Financial Statements.

Production Expenses

Lease operating expense

	Year Ended December 31,		
In thousands, except per BOE data	2013	2012	2011
Lease operating expense			
Tertiary – excluding Delhi Field remediation	$358,281	$ 307,686	$272,066
Tertiary – Delhi Field remediation	114,000	—	—
Non-tertiary	258,293	224,673	235,331
Total lease operating expense	$730,574	$532,359	$ 507,397
Lease operating expense per BOE			
Tertiary – excluding Delhi Field remediation	$ 25.51	$ 23.88	$ 24.08
Tertiary – Delhi Field remediation	8.12	—	—
Non-tertiary	22.28	16.83	18.58
Total lease operating expense per BOE (1)	28.50	20.29	21.17

(1) Excluding estimated lease operating expenses recorded during the year ended December 31, 2013 to remediate an area of Delhi Field, total lease operating expense per BOE averaged $24.05. See Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – Overview – Delhi Field Release,* and Note 11, *Commitments and Contingencies,* to the Consolidated Financial Statements for further discussion of this matter.

Total lease operating expense during 2013 increased on an absolute-dollar and per-BOE basis from 2012 primarily due to \$114.0 million in incurred and estimated lease operating expenses recorded for the costs to remediate an area of Delhi Field impacted by a release of well fluids discovered during the second quarter (see Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – Overview – Delhi Field Release,* and Note 11, *Commitments and Contingencies,* to the Consolidated Financial Statements). Excluding these incurred and estimated remediation expenses, lease operating expense increased \$84.2 million (16%) or \$3.76 per BOE during 2013 compared to 2012 levels due primarily to increased expenses resulting from the expansion of our tertiary floods, including our new tertiary flood at Bell Creek Field; increases in the cost and utilization of CO_2 between the comparative periods; and higher lease operating expenses at the fields we acquired in the Bakken Exchange Transaction relative to the Bakken assets we sold. Lease operating expense increased 5% between 2011 and 2012 on an absolute-dollar basis due to the expansion of our tertiary floods and decreased 4% on a per-BOE basis primarily due to the higher production volumes in our tertiary floods and growth in our Bakken production, which had a relatively low operating cost per barrel.

Excluding the incurred and estimated Delhi Field remediation expense, tertiary lease operating expense increased \$50.6 million (16%) or \$1.63 per Bbl during 2013 compared to 2012. The increase was primarily a result of the expansion of our tertiary floods, including our new tertiary flood at Bell Creek Field, and increased CO_2 expenses due to increases in the cost of CO_2 and an increase in CO_2 volumes injected into tertiary floods between years. During 2012, tertiary lease operating expense increased 13% on an absolute-dollar basis compared to 2011 levels, but decreased slightly on a per-BOE basis. The decrease in tertiary operating costs per barrel was due to the 14% increase in tertiary production, which more than offset the higher total tertiary operating expenses resulting from the increase in the number of our active tertiary floods due to the tertiary floods at Hastings and Oyster Bayou fields. For any specific field, we expect our tertiary lease operating expense per barrel to be high initially, as we experienced in 2013 with our Bell Creek flood, and then decrease as production increases, ultimately leveling off until production begins to decline in the later life of the field, when operating expense per barrel will again increase. One of our most substantial costs in our tertiary operations is our cost for fuel and utilities, averaging \$6.64 per Bbl in 2013, \$6.51 per Bbl in 2012 and \$6.31 per Bbl in 2011, which has increased on a per-barrel basis due to the higher cost of these items and the continued expansion of our tertiary floods.

Currently, our CO_2 expense comprises approximately one-fourth of our typical Gulf Coast tertiary operating expenses, and for the CO_2 reserves we already own, consists of our CO_2 production expenses, and for the CO_2 reserves we do not own, consists of our purchase of CO_2 from royalty and working interest owners and anthropogenic (man-made) sources. During the year ended December 31, 2013, approximately 69% of the CO_2 utilized in our Gulf Coast region CO_2 floods consisted of CO_2 owned and produced by us, and we purchased the remaining portion from third-party owners (primarily royalty owners). The price we pay others for CO_2 varies by source and is generally indexed to oil prices. When combining the production cost of the CO_2 we own with what we pay third parties for CO_2, our average cost of CO_2 for the Gulf Coast region during 2013 was approximately \$0.33 per Mcf, including taxes paid on CO_2 production but excluding depletion and depreciation of capital expended at our Jackson Dome source and CO_2 pipelines. This rate during 2013 was higher than the \$0.26 per Mcf spent during 2012 and 2011 primarily due to higher oil prices (to which the cost of CO_2 is partially tied) and increased volumes purchased from anthropogenic sources during 2013, which volumes have a higher purchase price but require a smaller capital outlay than CO_2 we obtain from the Jackson Dome area. Including depletion expense related to the Jackson Dome CO_2 production, but excluding depreciation of our CO_2 pipelines, our cost of CO_2 was \$0.42 per Mcf in 2013, \$0.33 per Mcf in 2012 and \$0.31 per Mcf in 2011.

Non-tertiary lease operating expense increased 15% on an absolute-dollar basis during 2013, compared to the prior year period, as declines resulting from the sale of our Bakken area assets were more than offset by increases in newly acquired fields, including Thompson field acquired in the second quarter of 2012, Webster and Hartzog Draw fields acquired in the Bakken Exchange Transaction in late 2012, and additional interests in CCA acquired in the first quarter of 2013. On a per-BOE basis, non-tertiary lease operating expense increased 32% from 2012 to 2013 due to increases in newly acquired fields, which have a higher per-BOE operating cost than the properties disposed in the Bakken Exchange Transaction. Non-tertiary lease operating expense decreased 5% on an absolute-dollar basis and decreased 9% on a per-BOE basis during 2012 compared to 2011. The lower operating expense per BOE was largely driven by increased production related to our Bakken area assets (which had lower operating costs than our other properties), and the sale of certain non-core assets during the first half of 2012, which had a higher operating cost per BOE compared to the average of our other properties.

Taxes other than income

Taxes other than income includes ad valorem, production and franchise taxes. Taxes other than income increased $16.2 million between 2012 and 2013 and increased $12.5 million between 2011 and 2012. The change in each period is generally aligned with fluctuations in oil and natural gas revenues. The increase during 2013 is further impacted by the change in the mix of properties subject to production and ad valorem taxes as a result of the Bakken Exchange Transaction and CCA acquisition.

General and Administrative Expenses ("G&A")

	Year Ended December 31,		
In thousands, except per BOE data and employees	2013	2012	2011
Gross cash compensation and administrative costs	$324,580	$296,696	$ 246,112
Gross stock-based compensation	42,091	37,897	39,875
Operator labor and overhead recovery charges	(166,012)	(141,358)	(125,466)
Capitalized exploration and development costs	(55,448)	(49,216)	(34,996)
Net G&A expense	$ 145,211	$ 144,019	$125,525
G&A per BOE:			
Net administrative costs	$ 4.47	$ 4.48	$ 3.98
Net stock-based compensation	1.19	1.01	1.26
Net G&A expense	$ 5.66	$ 5.49	$ 5.24
Employees as of December 31	1,501	1,432	1,308

On an absolute-dollar basis, net G&A expense increased slightly between 2012 and 2013 and increased 15% between 2011 and 2012 and on a per-BOE basis increased 3% between 2012 and 2013 and 5% between 2011 and 2012.

Gross cash compensation and administrative costs increased $27.9 million (9%) between 2012 and 2013 and $50.6 million (21%) between 2011 and 2012. The increase in both comparative periods is due to higher compensation-related costs from increases in headcount, annual merit increases and other employee-related costs such as health insurance. Employee bonus expense was relatively unchanged from 2012 to 2013 despite the 5% increase in headcount, as bonuses were paid at a lower rate in 2013 than in 2012, but contributed to the increase in gross administrative cost between 2011 and 2012.

Gross stock-based compensation costs increased in 2013 compared to 2012 due to the increased number of employees during 2013 compared to 2012. The increase to gross stock-based compensation as a result of additional headcount during 2012 compared to 2011 was more than offset by a shift in the mix of compensation to more cash-based compensation. Stock-based compensation, net of amounts capitalized or reclassified to field operations, was approximately $30.4 million in 2013, $26.5 million in 2012 and $30.3 million in 2011.

Our well operating agreements allow us, when we are the operator, to charge a well with a specified overhead rate during the drilling phase and also to charge a monthly fixed overhead rate for each producing well. In addition, salaries associated with field personnel are initially recorded as gross cash compensation and administrative costs and are subsequently reclassified to lease operating expenses or capitalized to field development costs to the extent those individuals are dedicated to oil and natural gas production, exploration, and development activities. As a result of additional operated wells, increased compensation expense and an increase in the COPAS overhead rate, the amount we recovered as operator labor and overhead recovery charges increased by 17% between 2012 and 2013, and 13% between 2011 and 2012. Capitalized exploration and development costs also increased between the periods, primarily due to increased compensation costs subject to capitalization.

Interest and Financing Expenses

	Year Ended December 31,		
In thousands, except per BOE data and interest rates	2013	2012	2011
Cash interest expense	$ 205,938	$ 216,205	$ 207,727
Noncash interest expense	14,024	14,808	18,219
Less: Capitalized interest	(79,253)	(77,432)	(61,586)
Interest expense, net	$ 140,709	$ 153,581	$ 164,360
Interest expense, net per BOE	$ 5.49	$ 5.85	$ 6.86
Average debt outstanding	$3,257,686	$2,935,485	$2,470,682
Average interest rate (1)	6.3%	7.4%	8.4%

(1) Includes commitment fees but excludes debt issue costs and amortization of discount or premium.

Interest expense, net decreased 8% between 2012 and 2013. The decrease in interest expense is due to a lower average interest rate, partially offset by higher average debt outstanding and higher capitalized interest. The decrease in the average interest rate between 2012 and 2013 is a result of refinancing our 9½% Notes and 9¾% Notes with our 2023 Notes, which carry a rate of 4⅝% (see *Overview – Debt Refinancing* above). During 2014, we expect capitalized interest to decline due to the completion of various development projects during the fourth quarter of 2013.

Interest expense, net decreased 7% between 2011 and 2012, largely due to higher capitalized interest, offset in part by higher cash interest expense resulting from an increase in average debt outstanding during the period. Capitalized interest increased 26% during 2012, compared to 2011 primarily due to incremental capitalized interest on the Riley Ridge gas processing facility and Greencore Pipeline construction projects.

Depletion, Depreciation and Amortization ("DD&A")

In thousands, except per BOE data	Year Ended December 31, 2013	2012	2011
Depletion and depreciation of oil and natural gas properties	$392,603	$420,094	$362,788
Depletion and depreciation of CO_2 properties	27,783	23,843	18,220
Asset retirement obligations	8,450	7,228	6,287
Depreciation of pipelines, plants and other property and equipment	81,107	56,373	21,901
Total DD&A	$509,943	$507,538	$409,196
DD&A per BOE:			
Oil and natural gas properties	$ 15.64	$ 16.28	$ 15.40
CO_2 and other fixed assets	4.25	3.06	1.67
Total DD&A cost per BOE	$ 19.89	$ 19.34	$ 17.07

We adjust our DD&A rate each quarter for significant changes in our estimates of oil and natural gas reserves and costs. In addition, under full cost accounting rules, the divestiture of oil and natural gas properties generally does not result in gain or loss recognition; instead, the proceeds of the disposition reduce the full cost pool. As such, our DD&A rate has changed significantly over time, and it may continue to change in the future. Depletion and depreciation of oil and natural gas properties decreased 7% on an absolute-dollar basis and 4% on a per-BOE basis between 2012 and 2013. These decreases were primarily due to the Bakken Exchange Transaction in late 2012, which resulted in a decrease in capitalized costs relating to the sales proceeds credited to the full cost pool and a significant reduction in future development costs relating to the sold proved reserves, partially offset by the reduction in total proved reserves. This decrease in DD&A was partially offset by the impact of the CCA Acquisition in the first quarter of 2013 and the movement of Bell Creek reserves from unevaluated to proved reserves during the fourth quarter of 2013.

Depletion and depreciation of oil and natural gas properties increased 16% on an absolute-dollar basis and 6% on a per-BOE basis between 2011 and 2012. During the first nine months of 2012, our DD&A rate for our oil and natural gas properties was $16.90 per BOE, which was higher than 2011 levels due to higher finding and development costs related to our Bakken capital program. However, in the fourth quarter of 2012, our DD&A rate for our oil and natural gas properties decreased to $14.39 per BOE due to the Bakken Exchange Transaction.

During 2013, we added 84.6 MMBOE of estimated proved reserves, including tertiary reserves of 34.0 MMBbls at Bell Creek Field based on the field's response to CO_2 injections, 42.2 MMBOE from the acquisition of additional interests in CCA Fields and 8.4 MMBOE of other additions and revisions. We reclassified approximately $417.6 million from unevaluated properties to the full cost pool relating to Bell Creek Field, representing the acquisition costs and development expenditures incurred on the field prior to recognizing proved reserves. Our depletion and depreciation rate of oil and natural gas properties increased to $16.90 per BOE during the fourth quarter of 2013, primarily as a result of the reclassification of Bell Creek costs to the full cost pool, increased finding and development costs, and the related recognition of additional proved reserves.

Depletion and depreciation of our CO_2 properties, pipelines, plants, and other property and equipment increased on an absolute-dollar and per-BOE basis during 2013 from 2012 levels, primarily due to an increase in CO_2 properties, pipelines and plants subject to depreciation as a result of continued development. The increase in 2013 was further impacted by a change in classification of our equipment leases from operating to capital during the second quarter of 2012, and the amount on a per-BOE basis was also impacted by lower oil and natural gas production during 2013. Depletion and depreciation of our CO_2 properties increased on an absolute-dollar and per-BOE basis in 2012 compared to 2011 due to increased drilling activity at Jackson Dome, and depreciation of other fixed assets increased during the same period due to incremental pipeline depreciation and the change in classification of our equipment leases.

Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. Under these rules, the full cost ceiling value is calculated using a 12-month average price based on the first-day price of every month during the period. We did not have a ceiling test write-down during 2013, 2012 or 2011. However, if oil prices were to decrease significantly in subsequent periods, we may be required to record write-downs under the full cost pool ceiling test in the future. The possibility and amount of any future write-down is difficult to predict, and will depend, in part, upon oil and natural gas prices, the incremental proved reserves that may be added each period, revisions to previous reserve estimates and future capital expenditures, as well as additional capital spent.

Income Taxes

	Year Ended December 31,		
In thousands, except per BOE amounts and tax rates	2013	2012	2011
Current income tax expense	$ 10,257	$ 75,754	$ 8,249
Deferred income tax expense	222,526	255,743	342,463
Total income tax expense	$ 232,783	$ 331,497	$ 350,712
Average income tax expense per BOE	$ 9.08	$ 12.63	$ 14.63
Effective tax rate	36.2%	38.7%	38.0%
Total net deferred tax liability	$2,346,540	$2,124,296	$1,868,420

Our income tax provisions for 2013 and 2011 were based on an estimated statutory rate of approximately 38%, while the 2012 tax provision was based on an estimated statutory rate of approximately 38.5%. The fluctuation in our statutory rate is significantly driven by a shift in the amount of revenues we earn in each state due to acquisitions and divestitures and other production changes. Our 2013 effective tax rate was lower than our statutory rate due to the revaluation of our deferred taxes as a result of the lower overall statutory rate compared to 2012, as well as the change in treatment of certain items between our 2012 tax provision and our 2012 tax returns. Our effective tax rate was consistent with our estimated statutory rates in 2012 and 2011.

During 2012, for federal income tax purposes, we structured the divestitures of our Bakken area assets and certain non-core assets as like-kind-exchange transactions for interests acquired in Thompson, Webster, Hartzog Draw and LaBarge fields as well as the CCA Acquisition in 2013 (see Note 2, *Acquisitions and Divestitures,* to the Consolidated Financial Statements), thereby deferring the majority of the taxable gain on those divestitures. The increase in current income tax expense during 2012 included $42 million of current taxes resulting from the taxable gain recognized in the Bakken Exchange Transaction that we were unable to defer through a like-kind exchange transaction. Current income tax expense during 2013 is primarily related to state income taxes while current income tax during 2012 and 2011 also includes our alternative minimum cash taxes that we cannot offset with enhanced oil recovery credits, as well as state income taxes. We currently expect our cash taxes in the future to increase over 2013 cash taxes. Our current income tax expense during 2011 was offset by a net benefit due to the change in treatment for certain items between our 2010 tax provision and our 2010 filed tax return. This change in treatment resulted in a reclassification of approximately $16.9 million from current to deferred taxes.

As of December 31, 2013, we had an estimated $15.0 million of enhanced oil recovery credits to carry forward related to our tertiary operations, and $34.8 million of alternative minimum tax credits that can be utilized to reduce our current income taxes during 2014 or future years. These enhanced oil recovery credits do not begin to expire until 2025. Since the ability to earn additional enhanced oil recovery credits is based upon the level of oil prices, we would not currently expect to earn additional enhanced oil recovery credits unless oil prices were to significantly deteriorate.

Per-BOE Data

The following table summarizes our cash flow, DD&A and results of operations on a per-BOE basis for the comparative periods. Each of the individual components is discussed above.

	Year Ended December 31,		
Per-BOE data	2013	2012	2011
Oil and natural gas revenues	$ 96.19	$ 91.85	$ 94.68
Cash receipt (payment) on settlements of commodity derivatives	(0.03)	0.68	0.10
Lease operating expenses – excluding Delhi Field remediation	(24.05)	(20.29)	(21.17)
Lease operating expenses – Delhi Field remediation	(4.45)	—	—
Production and ad valorem taxes	(6.35)	(5.71)	(5.81)
Marketing expenses, net of third party purchases	(1.47)	(1.60)	(1.09)
Production netback	59.84	64.93	66.71
CO_2 sales, net of operating and exploration expenses	0.43	0.45	0.36
General and administrative expenses	(5.66)	(5.49)	(5.24)
Interest expense, net	(5.49)	(5.85)	(6.86)
Other	0.48	(1.44)	1.77
Changes in assets and liabilities relating to operations	3.49	1.17	(6.47)
Cash flow from operations	53.09	53.77	50.27
DD&A	(19.89)	(19.34)	(17.07)
Deferred income taxes	(8.68)	(9.75)	(14.29)
Loss on early extinguishment of debt	(1.74)	—	(0.67)
Noncash fair value adjustments on commodity derivatives	(1.57)	(0.50)	2.09
Impairment of assets	—	(0.67)	(0.96)
Other noncash items	(5.23)	(3.49)	4.55
Net income	$ 15.98	$ 20.02	$ 23.92

Market Risk Management

Restricted Cash

Restricted cash on our Consolidated Balance Sheet as of December 31, 2012 consisted of proceeds from the Bakken Exchange Transaction (see Note 2, *Acquisitions and Divestitures,* to the Consolidated Financial Statements) previously held by a qualified intermediary and which were restricted for application towards future potential acquisitions to enable a like-kind-exchange transaction for federal income tax purposes. We managed and controlled counterparty credit risk related to this restricted cash using a trust agreement, whereby the assets held in trust must be segregated from the financial institution's assets, and in the event of its bankruptcy, the funds would not be subject to payments to the creditors of the financial institution.

Debt

We finance some of our acquisitions and other expenditures with fixed and variable rate debt. These debt agreements expose us to market risk related to changes in interest rates. At December 31, 2013, we had $340.0 million in outstanding borrowings on our bank credit facility. None of our existing debt has any triggers or covenants regarding our debt ratings with rating agencies, although under the NEJD financing lease, in the event of significant downgrades of our corporate credit rating by the rating agencies, certain credit enhancements can be required from us, and possibly other remedies made available under the lease. The fair value of our senior subordinated debt is based on quoted market prices. The following table presents the principal cash flows and fair values of our outstanding debt at December 31, 2013:

In thousands	2014	2015	2016	2017	2020	2021	2023	Total	Fair Value
Variable rate debt:									
Bank credit facility (weighted average interest rate of 1.9% at December 31, 2013)	$ —	$ —	$340,000	$ —	$ —	$ —	$ —	$ 340,000	$ 340,000
Fixed rate debt:									
8¼% Senior Subordinated Notes due 2020	—	—	—	—	996,273	—	—	996,273	1,097,096
6 3/8% Senior Subordinated Notes due 2021	—	—	—	—	—	400,000	—	400,000	425,000
4 5/8% Senior Subordinated Notes due 2023	—	—	—	—	—	—	1,200,000	1,200,000	1,092,000
Other Subordinated Notes	1,072	485	—	2,250	—	—	—	3,807	2,735

See Note 5, *Long-Term Debt,* to the Consolidated Financial Statements for details regarding our long-term debt.

Oil and Natural Gas Derivative Contracts

From time to time, we enter into oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production. These contracts have consisted of price floors, collars and fixed price swaps. We do not hold or issue derivative financial instruments for trading purposes. The production that we hedge has varied from year to year, depending on our levels of debt and financial strength and expectation of future commodity prices. We currently employ a strategy to hedge a portion of our forecasted production for approximately 18 months to two years in the future from the current quarter, as we believe it is important to protect our future cash flow for that time in order to give us time to adjust to commodity price fluctuations, particularly since many of our expenditures have long lead times (see *Capital Resources and Liquidity* above). Now that we are paying a dividend, we may look to extend the periods covered by our hedges further into the future, possibly for periods up to three years, in order to provide greater certainty around oil and natural gas prices and projected cash flows. Also, in December 2013, we converted our 2014 oil collars to fixed-price swaps and in early 2014, we converted a portion of our 2015 oil collars to fixed-price swaps. See Note 9, *Commodity Derivative Contracts,* to the Consolidated Financial Statements for additional information regarding our commodity derivative contracts.

All of the mark-to-market valuations used for our oil and natural gas derivatives are provided by external sources. We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures and diversification. All of our commodity derivative contracts are with parties that are lenders under our bank credit facility. We have included an estimate of nonperformance risk in the fair value measurement of our oil and natural gas derivative contracts, which we have measured for nonperformance risk based upon credit default swaps or credit spreads.

For accounting purposes, we do not apply hedge accounting to our oil and natural gas derivative contracts. This means that any changes in the fair value of these commodity derivative contracts will be charged to earnings on a quarterly basis instead of charging the effective portion to other comprehensive income and the ineffective portion to earnings.

At December 31, 2013, our commodity derivative contracts were recorded at their fair value, which was a net liability of approximately $47.3 million, a $40.4 million increase from the $6.9 million net liability recorded at December 31, 2012. This change is primarily related to the expiration of oil derivative contracts during 2013, new commodity derivative contracts we entered into during 2013 for future periods, and to the oil and natural gas futures prices as of December 31, 2013.

Commodity Derivative Sensitivity Analysis

Based on NYMEX and LLS crude oil futures prices and natural gas futures prices as of December 31, 2013, and assuming both a 10% increase and decrease thereon, we would expect to make or receive payments on our crude oil and natural gas derivative contracts as shown in the following table:

In thousands	Crude Oil Derivative Contracts Receipt/(Payment)	Natural Gas Derivative Contracts Receipt/(Payment)
Based on:		
NYMEX futures prices as of December 31, 2013	$ (58,377)	$ —
10% increase in prices	(286,016)	(930)
10% decrease in prices	167,853	1,348

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in accordance with generally accepted accounting principles requires that we select certain accounting policies and make certain estimates and judgments regarding the application of those policies. Our significant accounting policies are included in Note 1, *Significant Accounting Policies,* to the Consolidated Financial Statements. These policies, along with the underlying assumptions and judgments by our management in their application, have a significant impact on our consolidated financial statements. Following is a discussion of our most critical accounting estimates, judgments and uncertainties that are inherent in the preparation of our financial statements.

Full Cost Method of Accounting, Depletion and Depreciation and Oil and Natural Gas Properties

Businesses involved in the production of oil and natural gas are required to follow accounting rules that are unique to the oil and gas industry. We apply the full cost method of accounting for our oil and natural gas properties. Another acceptable method of accounting for oil and natural gas production activities is the successful efforts method of accounting. In general, the primary differences between the two methods are related to the capitalization of costs and the evaluation for asset impairment. Under the full cost method, all geological and geophysical costs, exploratory dry holes and delay rentals are capitalized to the full cost pool, whereas under the successful efforts method such costs are expensed as incurred. In the assessment of impairment of oil and natural gas properties, the successful efforts method follows the FASB guidance under the *Accounting for the Impairment or Disposal of Long-Lived Assets* topic of the FASC, under which the net book value of assets is measured for impairment against the undiscounted future cash flows using commodity prices consistent with management expectations. Under the full cost method, the full cost pool (net book value of oil and natural gas properties) is measured against future cash flows discounted at 10% using the average first-day-of-the-month oil and natural gas price for each month during the 12-month period ended as of each quarterly reporting period. The financial results for a given period could be substantially different depending on the method of accounting that an oil and gas entity applies. Further, we do not designate our oil and natural gas derivative contracts as hedge instruments for accounting purposes under the *Derivatives and Hedging* topic of the FASC (see below), and as a result, these contracts are not considered in the full cost ceiling test.

We make significant estimates at the end of each period related to accruals for oil and natural gas revenues, production, capitalized costs and operating expenses. We calculate these estimates with our best available data, which includes, among other things, production reports, price posting, information compiled from daily drilling reports and other internal tracking devices, and analysis of historical results and trends. While management is not aware of any required revisions to its estimates, there will likely be future adjustments resulting from such things as changes in ownership interests, payouts, joint venture audits, re-allocations by the purchaser/pipeline, or other corrections and adjustments common in the oil and gas industry, many of which will require retroactive application. These types of adjustments cannot be currently estimated or determined and will be recorded in the period during which the adjustment occurs.

Under full cost accounting, the estimated quantities of proved oil and natural gas reserves used to compute depletion and the related present value of estimated future net cash flows therefrom used to perform the full cost ceiling test have a significant impact on the underlying financial statements. The process of estimating oil and natural gas reserves is very complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and continued reassessment of the viability of production under varying economic conditions. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that the reported reserve estimates represent the most accurate assessments possible, including the hiring of independent engineers to prepare reported estimates, the subjective decisions and variances in available data for various fields make these estimates generally less precise than other estimates included in our financial statement disclosures. Over the last four years, annual revisions to our reserve estimates have averaged approximately 2.0% of the previous year's estimates and have been both positive and negative.

Changes in commodity prices also affect our reserve quantities. Between 2011 and 2012, oil and natural gas prices used to calculate reserve quantities in our year-end proved reserve report decreased, resulting in a decrease in our proved reserves of 6.7 MMBOE. Between 2012 and 2013, oil and natural gas prices used to calculate year-end proved reserves increased, resulting in an increase in our proved reserves of 3.0 MMBOE. These changes in quantities affect our DD&A rate, and the combined effect of changes in quantities and commodity prices impacts our full cost ceiling test calculation. For example, we estimate that a 5% increase in our estimate of proved reserves quantities would have lowered our fourth quarter 2013 DD&A rate from $16.90 per BOE to approximately $16.12 per BOE, and a 5% decrease in our proved reserve quantities would have increased our DD&A rate to approximately $17.76 per BOE. Also, reserve quantities and their ultimate values, determined solely by our lenders, are the primary factors in determining the maximum borrowing base under our bank credit facility.

Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized cost or the cost center ceiling. The cost center ceiling is defined as (1) the present value of our future net revenues from proved reserves before future abandonment costs calculated using the average first-day-of-the-month oil and natural gas price for each month during the 12-month period then ended, discounted at 10%; plus (2) the cost of properties not being amortized; plus (3) the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less (4) related income tax effects. Our future net revenues from proved reserves are not reduced for development costs related to the cost of drilling for and developing CO_2 reserves nor for those related to the cost of constructing CO_2 pipelines, as those costs have already been incurred by the Company. Therefore, we include in the ceiling test, as a reduction of future net revenues, that portion of our capitalized CO_2 costs related to CO_2 reserves and CO_2 pipelines that we estimate will be consumed in the process of producing our proved oil and natural gas reserves. The fair value of our oil and natural gas derivative contracts is not included in the ceiling test, as we do not designate these contracts as hedge instruments for accounting purposes.

We did not have a full cost pool ceiling test write-down in 2013, 2012 or 2011. Crude oil prices decreased between 2011 and 2012, and increased during 2013, with first-day-of-the-month NYMEX oil prices during 2013 averaging $96.94 per Bbl during the year. First-day-of-the-month unweighted average NYMEX natural gas prices during 2013 of $3.67 per Mcf were higher than unweighted average natural gas prices for 2012. Commodity prices have historically been volatile and are expected to continue to be so in the future. If oil and natural gas prices should decrease, we may be required to record write-downs due to the full cost ceiling test. The amount of any future write-down is difficult to predict and will depend upon the oil and natural gas prices utilized in the ceiling test, the incremental proved reserves that might be added during each period and additional capital spent.

Tertiary Injection Costs

Our tertiary operations are conducted in reservoirs that have already produced significant amounts of oil over many years; however, in accordance with the rules for recording proved reserves, we cannot recognize proved reserves associated with enhanced recovery techniques such as CO_2 injection until we can demonstrate production resulting from the tertiary process or unless the field is analogous to an existing flood. Our costs associated with the CO_2 we produce (or acquire) and inject are principally our cash out-of-pocket costs of production, transportation and acquisition, and to pay royalties.

We capitalize, as a development cost, injection costs in fields that are in their development stage, which means we have not yet seen incremental oil production due to the CO_2 injections (i.e., a production response). These capitalized development costs will be included in our unevaluated property costs if there are not already proved tertiary reserves in that field. After we see a production response to the CO_2 injections (i.e., the production stage), injection costs will be expensed as incurred, and any previously deferred unevaluated development costs will become subject to depletion upon recognition of proved tertiary reserves. During 2013, 2012 and 2011, we capitalized $38.7 million, $36.8 million and $65.3 million, respectively, of tertiary injection costs associated with our tertiary projects.

Income Taxes

We make certain estimates and judgments in determining our income tax expense for financial reporting purposes. These estimates and judgments occur in the calculation of certain tax assets and liabilities that arise from differences in the timing and recognition of revenue and expense for tax and financial reporting purposes. Our federal and state income tax returns are generally not prepared or filed before the consolidated financial statements are prepared; therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits and net operating loss carryforwards. Adjustments related to these estimates are recorded in our tax provision in the period in which we finalize our income tax returns. Further, we must assess the likelihood that we will be able to recover or utilize our deferred tax assets (primarily our enhanced oil recovery credits and state loss carryforwards). If recovery is not likely, we must record a valuation allowance against such deferred tax assets for the amount we would not expect to recover, which would result in an increase to our income tax expense. As of December 31, 2013, we believe that all of our deferred tax assets recorded on our Consolidated Balance Sheet will ultimately be recovered. If our estimates and judgments change regarding our ability to utilize our deferred tax assets, our tax provision would increase in the period it is determined that recovery is not likely. A 1% increase in our effective tax rate would have increased our calculated income tax expense by approximately $6.4 million, $8.6 million and $9.2 million for the years ended December 31, 2013, 2012 and 2011, respectively. See Note 6, *Income Taxes,* to the Consolidated Financial Statements and see *Income Taxes* above for further information concerning our income taxes.

Fair Value Estimates

The FASC defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. It does not require us to make any new fair value measurements, but rather establishes a fair value hierarchy that prioritizes the inputs to the valuation techniques used to measure fair value. Level 1 inputs are given the highest priority in the fair value hierarchy, as they represent observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date, while Level 3 inputs are given the lowest priority, as they represent unobservable inputs that are not corroborated by market data. Valuation techniques that maximize the use of observable inputs are favored. See Note 10, *Fair Value Measurements,* to the Consolidated Financial Statements for disclosures regarding our recurring fair value measurements.

Significant uses of fair value measurements include:

- allocation of the purchase price paid to acquire businesses to the assets acquired and liabilities assumed in those acquisitions;
- assessment of impairment of long-lived assets;
- assessment of impairment of goodwill; and
- recorded value of commodity derivative instruments.

Acquisitions

Under the acquisition method of accounting for business combinations, the purchase price paid to acquire a business is allocated to its assets and liabilities based on the estimated fair values of the assets acquired and liabilities assumed as of the date of acquisition. The FASC *Fair Value Measurements and Disclosures* topic defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (often referred to as the "exit price"). A fair value measurement is based on the assumptions of market participants and not those of the reporting entity. Therefore, entity-specific intentions do not impact the measurement of fair value unless those assumptions are consistent with market participant views.

The excess of the purchase price over the fair value (as defined by the FASC *Fair Value Measurements and Disclosures* topic) of the net tangible and identifiable intangible assets acquired is recorded as goodwill. A significant amount of judgment is involved in estimating the individual fair values involving long-term tangible assets, identifiable intangible assets and long-term asset retirement obligations. We use all available information to estimate the fair values of assets acquired and liabilities assumed in an acquisition and engage a third-party consultant to review certain assumptions utilized in our valuations.

Specifically, the FASC *Fair Value Measurements and Disclosures* topic requires us to value oil properties recoverable through enhanced oil recovery by estimating the cost a third party market participant would pay for CO_2. A third party's economics and access to CO_2 is substantially different in our operating regions than our own, as CO_2 is limited and there may be no known CO_2 available in a given area except through our own sources. These factors generally result in our estimation of the cost of CO_2 to a market participant being higher than our cost. Because of our strategic advantage relating to CO_2 supply and associated infrastructure, a third party's economics (the required basis for allocating values) for a potential EOR flood will be less than ours. Therefore, we cannot attribute much, if any, of our purchase price relating to the future EOR flood to unevaluated properties, even though we may have attributed value to the future flood when we made the purchase decision. As such, we must attribute the unallocated purchase price to goodwill, which has resulted in our recognition of more goodwill than most of our industry peers.

The fair values used to allocate the purchase price of an acquisition are often estimated using the expected present value of future cash flows method, which requires us to project related future cash inflows and outflows and apply an appropriate discount rate. The estimates used in determining fair values are based on assumptions believed to be reasonable but that are inherently uncertain. Accordingly, actual results may differ from the projected results used to determine fair value.

Impairment Assessment of Goodwill

We test goodwill for impairment annually during the fourth quarter, or between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. The need to test for impairment can be based on several indicators, including a significant reduction in prices of oil or natural gas, a full-cost ceiling write-down of oil and natural gas properties, unfavorable adjustments to reserves, significant changes in the expected timing of production, other changes to contracts or changes in the regulatory environment.

Goodwill is tested for impairment at the reporting unit level. Denbury applies SEC full cost accounting rules, under which the acquisition cost of oil and gas properties is recognized on a cost center basis (country), of which Denbury has only one cost center (United States). Goodwill is assigned to this single reporting unit.

In each period that a goodwill impairment test is performed, we have the option to assess qualitative factors to determine if it is more likely than not that our reporting unit's fair value is less than its carrying amount. The following events and circumstances are certain of the qualitative factors we consider in evaluating whether it is more likely than not the fair value of our reporting unit is less than its carrying amount:

- Macroeconomic conditions, such as deterioration in general economic conditions, limitations on accessing capital, or other developments in equity and credit markets;
- Industry and market conditions, such as deterioration in the environment in which we operate, including significant declines in oil prices, inability to access oil field equipment and/or qualified personnel and regulations impacting the oil and natural gas industry, among others;
- Cost factors, such as increases in power and labor costs;
- Overall financial performance, such as negative or declining cash flows or a decline in actual or forecasted revenues or earnings;
- Other relevant Company-specific events, such as material changes in management or key personnel, a change in strategy or litigation;
- Material events, such as a change in the composition or carrying amount of our reporting unit's net assets, including acquisitions and dispositions; and
- Consideration of the relationship of our market capitalization to our book value, as well as a sustained decrease in our share price.

If we determine that it is more likely than not that our reporting unit's fair value is less than its carrying amount, we will proceed to step 1 of the 2-step quantitative goodwill assessment, in which we perform a calculation to compare the fair value of our reporting unit to its carrying cost. In any given period, we have the option to bypass the qualitative assessment and proceed directly to step 1 of the 2-step quantitative goodwill impairment test.

Fair value calculated for the purpose of testing for impairment of our goodwill is estimated using the expected present value of future cash flows method, and comparative market prices and net asset value when appropriate. The Company also takes into consideration the Company's market capitalization, including a control premium. A significant amount of judgment is involved in performing these fair value estimates for goodwill, since the results are based on forecasted assumptions. Significant assumptions include projections of future oil and natural gas prices, projections of estimated quantities of oil and natural gas reserves, projections of future rates of production, timing and amount of future development and operating costs, projected availability and cost of CO_2, projected recovery factors of tertiary reserves and risk-adjusted discount rates. We base our fair value estimates on projected financial information that we believe to be reasonable. However, actual results may differ from those projections.

We completed our goodwill impairment assessment during the fourth quarter of 2013 and did not record any goodwill impairment during 2013, nor have we recorded a goodwill impairment historically.

Oil and Natural Gas Derivative Contracts

We enter into oil and natural gas derivative contracts to mitigate our exposure to commodity price risk associated with future oil and natural gas production. These contracts have historically consisted of options, in the form of price floors or collars, and fixed price swaps. We do not designate these commodity derivative contracts as hedge instruments for accounting purposes under the FASC *Derivatives and Hedging* topic. This means that any changes in the fair value of these commodity derivative contracts will be charged to earnings on a quarterly basis instead of charging the effective portion to other comprehensive income and the balance to earnings. While we may experience more volatility in our net income than if we were to apply hedge accounting treatment as permitted by the FASC *Derivatives and Hedging* topic, we believe that for us the benefits associated with applying hedge accounting do not outweigh the cost, time and effort to comply with hedge accounting.

Environmental and Litigation Contingencies

The Company makes judgments and estimates in recording liabilities for contingencies such as environmental remediation or ongoing litigation. Liabilities are recorded when it is both probable that a loss has been incurred and such loss is reasonably estimable. Assessments of liabilities are based on information obtained from independent and in-house experts, loss experience in similar situations, actual costs incurred, and other case-by-case factors. Actual costs can vary from such estimates for a variety of reasons. The costs of environmental remediation or litigation can vary from estimates due to new developments regarding the facts and circumstances of each event, including in the case of environmental remediation, the timing of remediation, our understanding of the environmental impact, remediation methods available, and regulatory requirements, and in the case of litigation, differing interpretations of laws and facts and assessments of damages asserted and/or incurred.

Use of Estimates

See Note 1, *Significant Accounting Policies,* to the Consolidated Financial Statements for a discussion of our use of estimates.

Recent Accounting Pronouncements

See Note 1, *Significant Accounting Policies,* to the Consolidated Financial Statements for a discussion of the effects of recently issued and recently adopted accounting pronouncements.

FORWARD-LOOKING INFORMATION

The statements contained in this Annual Report on Form 10-K that are not historical facts, including, but not limited to, statements found in the sections entitled "Business" and "Management's Discussion and Analysis of Financial Condition and Results of Operations," are forward-looking statements, as that term is defined in Section 21E of the Securities and Exchange Act of 1934, as amended, that involve a number of risks and uncertainties. Such forward-looking statements may be or may concern, among other things, forecasted capital expenditures, drilling activity or methods including the timing and location thereof, estimated timing of pipeline construction or completion or the cost thereof, dates of completion of to-be-constructed industrial plants and the initial date of capture of anthropogenic CO_2 from such plants, timing of CO_2 injections and initial production responses in tertiary flooding projects, acquisition plans and proposals and dispositions, development activities, finding costs, cost savings, capital budgets, production rates and volumes or forecasts thereof, assumptions regarding payment of future cash dividends to shareholders, the rate thereof, or the sustainability or growth of future payments, hydrocarbon reserve quantities and values, CO_2 reserves, helium reserves, potential reserves, percentages of recoverable original oil in place, hydrocarbon prices, pricing or cost assumptions based on current and projected oil and gas prices, liquidity, cash flows, availability of capital, borrowing capacity, regulatory matters, prospective legislation affecting the oil and gas industry, mark-to-market values, competition, long-term forecasts of production, finding costs, rates of return, estimated costs, or changes in costs, future capital expenditures and overall economics and other variables surrounding our operations and future plans. Such forward-looking statements generally are accompanied by words such as "plan," "estimate," "expect," "predict," "anticipate," "projected," "should," "assume," "believe," "target" or other words that convey the uncertainty of future events or outcomes. Such forward-looking information is based upon management's current plans, expectations, estimates and assumptions and is subject to a number of risks and uncertainties that could significantly affect current plans, anticipated actions, the timing of such actions and our financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates or assumptions expressed in or implied by any forward-looking statements made by us or on our behalf. Among the factors that could cause actual results to differ materially are fluctuations of the prices received or demand for our oil and natural gas; effects of our indebtedness; success of our risk management techniques; inaccurate cost estimates; availability of and fluctuations in the prices of goods and services; the uncertainty of drilling results and reserve estimates; operating hazards; disruption of operations and damages from hurricanes or tropical storms; acquisition risks; requirements for capital or its availability; conditions in the financial and credit markets; general economic conditions; competition and government regulations; and unexpected delays, as well as the risks and uncertainties inherent in oil and gas drilling and production activities or that are otherwise discussed in this annual report, including, without limitation, the portions referenced above, and the uncertainties set forth from time to time in our other public reports, filings and public statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The information required by Item 7A is set forth under *Market Risk Management* in Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations.*

Item 8. Financial Statements and Supplementary Information

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Denbury Resources Inc.:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Denbury Resources Inc. and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control – Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Dallas, Texas
February 28, 2014

CONSOLIDATED BALANCE SHEETS

In thousands, except par value and share data	December 31, 2013	December 31, 2012
Assets		
Current assets		
Cash and cash equivalents	$ 12,187	$ 98,511
Restricted cash	—	1,050,015
Accrued production receivable	262,047	253,131
Trade and other receivables, net	78,295	81,971
Derivative assets	5	19,477
Deferred tax assets	52,754	29,156
Other current assets	9,271	10,493
Total current assets	414,559	1,542,754
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved properties	8,945,326	6,963,211
Unevaluated properties	780,481	809,154
CO_2 properties	1,117,167	1,032,653
Pipelines and plants	2,209,560	2,035,126
Other property and equipment	466,969	417,207
Less accumulated depletion, depreciation, amortization and impairment	(3,668,225)	(3,180,241)
Net property and equipment	9,851,278	8,077,110
Derivative assets	9,942	36
Goodwill	1,283,590	1,283,590
Other assets	229,368	235,852
Total assets	$11,788,737	$11,139,342
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 410,543	$ 414,668
Oil and gas production payable	174,677	161,945
Derivative liabilities	53,822	2,842
Current maturities of long-term debt	36,157	36,966
Total current liabilities	675,199	616,421
Long-term liabilities		
Long-term debt, net of current portion	3,260,625	3,104,462
Asset retirement obligations	119,888	102,730
Derivative liabilities	3,413	23,781
Deferred tax liabilities	2,399,294	2,153,452
Other liabilities	28,912	23,607
Total long-term liabilities	5,812,132	5,408,032
Commitments and contingencies (Note 11)		
Stockholders' equity		
Preferred stock, $.001 par value, 25,000,000 shares authorized, none issued and outstanding	—	—
Common stock, $.001 par value, 600,000,000 shares authorized; 409,215,573 and 406,163,194 shares issued, respectively	409	406
Paid-in capital in excess of par	3,186,714	3,136,461
Retained earnings	2,844,432	2,434,835
Accumulated other comprehensive loss	(276)	(348)
Treasury stock, at cost, 46,710,896 and 30,601,262 shares, respectively	(729,873)	(456,465)
Total stockholders' equity	5,301,406	5,114,889
Total liabilities and stockholders' equity	$11,788,737	$11,139,342

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
In thousands, except per share data	2013	2012	2011
Revenues and other income			
Oil, natural gas, and related product sales	$2,466,234	$2,409,867	$2,269,151
CO_2 sales and transportation fees	27,950	26,453	22,711
Interest income and other income	22,943	20,152	17,462
Total revenues and other income	2,517,127	2,456,472	2,309,324
Expenses			
Lease operating expenses	730,574	532,359	507,397
Marketing expenses	49,246	52,836	26,047
CO_2 discovery and operating expenses	16,916	14,694	14,258
Taxes other than income	176,231	160,016	147,534
General and administrative expenses	145,211	144,019	125,525
Interest, net of amounts capitalized of $79,253, $77,432 and $61,586, respectively	140,709	153,581	164,360
Depletion, depreciation and amortization	509,943	507,538	409,196
Commodity derivatives expense (income)	41,024	(4,834)	(52,497)
Loss on early extinguishment of debt	44,651	—	16,131
Impairment of assets	—	17,515	22,951
Other expenses	20,242	21,891	4,377
Total expenses	1,874,747	1,599,615	1,385,279
Income before income taxes	642,380	856,857	924,045
Income tax provision	232,783	331,497	350,712
Net Income	$ 409,597	$ 525,360	$ 573,333
Net income per common share			
Basic	$ 1.12	$ 1.36	$ 1.45
Diluted	$ 1.11	$ 1.35	$ 1.43
Weighted average common shares outstanding			
Basic	366,659	385,205	396,023
Diluted	369,877	388,938	400,958

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE OPERATIONS

	Year Ended December 31,		
In thousands	2013	2012	2011
Net income	$409,597	$525,360	$573,333
Other comprehensive income, net of income tax:			
Interest rate lock derivative contracts reclassified to income, net of tax of $40, $43 and $43, respectively	72	70	70
Total other comprehensive income	72	70	70
Comprehensive income	$409,669	$525,430	$573,403

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
In thousands	2013	2012	2011
Cash flow from operating activities			
Net income	$ 409,597	$ 525,360	$ 573,333
Adjustments to reconcile net income to cash flow from operating activities			
Depletion, depreciation and amortization	509,943	507,538	409,196
Deferred income taxes	222,526	255,743	342,463
Stock-based compensation	33,003	29,310	33,190
Commodity derivatives expense (income)	41,024	(4,834)	(52,497)
Cash receipt (payment) on settlements of commodity derivatives	(662)	17,880	2,377
Loss on early extinguishment of debt	44,651	—	16,131
Amortization of debt issuance costs and discounts	14,023	14,695	16,954
Impairment of assets	—	17,515	22,951
Other, net	(2,318)	16,917	(4,190)
Changes in assets and liabilities, net of effects from acquisitions			
Accrued production receivable	(15,085)	36,234	(74,781)
Trade and other receivables	4,981	45,836	(55,470)
Other current and long-term assets	10,462	7,688	(15,817)
Accounts payable and accrued liabilities	91,816	5,828	(35,462)
Oil and natural gas production payable	12,731	(23,460)	54,391
Other liabilities	(15,497)	(41,359)	(27,955)
Net cash provided by operating activities	1,361,195	1,410,891	1,204,814
Cash flow used for investing activities			
Oil and natural gas capital expenditures	(900,221)	(1,122,615)	(1,082,853)
Acquisitions of oil and natural gas properties	(9,243)	(156,082)	(35,305)
Cash paid in Riley Ridge acquisition	—	—	(199,263)
Bakken exchange transaction	(10,385)	281,669	—
CO_2 capital expenditures	(93,744)	(131,043)	(84,789)
Pipelines and plants capital expenditures	(184,286)	(330,417)	(236,133)
Purchases of other assets	(65,987)	(25,765)	(28,838)
Net proceeds from sales of oil and natural gas properties and equipment	8,037	34,750	69,370
Net proceeds from sale of short-term investments	—	83,545	—
Other	(19,480)	(10,883)	(8,147)
Net cash used for investing activities	(1,275,309)	(1,376,841)	(1,605,958)
Cash flow provided by (used for) financing activities			
Bank repayments	(1,550,000)	(1,555,000)	(330,000)
Bank borrowings	1,190,000	1,870,000	715,000
Repayment of senior subordinated notes	(651,270)	—	(525,000)
Premium paid on repayment of senior subordinated notes	(36,475)	—	(13,137)
Net proceeds from issuance of senior subordinated notes	1,200,000	—	400,000
Costs of debt financing	(20,161)	(34)	(13,123)
Common stock repurchase program	(281,958)	(251,480)	(195,227)
Other	(22,346)	(17,718)	(545)
Net cash provided by (used for) financing activities	(172,210)	45,768	37,968
Net increase (decrease) in cash and cash equivalents	(86,324)	79,818	(363,176)
Cash and cash equivalents at beginning of year	98,511	18,693	381,869
Cash and cash equivalents at end of year	$ 12,187	$ 98,511	$ 18,693

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

Dollar amounts in thousands	Common Stock ($.001 Par Value)		Paid-In Capital in Excess of Par	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock (at cost)		Total Equity
	Shares	Amount				Shares	Amount	
Balance – December 31, 2010	400,291,033	$400	$3,045,937	$1,336,142	$(488)	78,524	$ (1,284)	$4,380,707
Stock Repurchase Program	—	—	—	—	—	14,112,610	(195,227)	(195,227)
Issued or purchased pursuant to employee stock compensation plans	2,623,962	3	4,685	—	—	—	—	4,688
Issued pursuant to employee stock purchase plan	11,330	—	(1,623)	—	—	(666,867)	12,858	11,235
Issued pursuant to directors' compensation plan	19,745	—	309	—	—	—	—	309
Stock-based compensation	—	—	40,187	—	—	—	—	40,187
Income tax benefit from equity awards	—	—	879	—	—	—	—	879
Tax withholding – stock compensation	—	—	—	—	—	441,406	(9,683)	(9,683)
Derivative contracts, net	—	—	—	—	70	—	—	70
Net income	—	—	—	573,333	—	—	—	573,333
Balance – December 31, 2011	402,946,070	403	3,090,374	1,909,475	(418)	13,965,673	(193,336)	4,806,498
Stock Repurchase Program	—	—	—	—	—	16,978,008	(266,657)	(266,657)
Issued or purchased pursuant to employee stock compensation plans	3,197,476	3	6,021	—	—	—	—	6,024
Issued pursuant to employee stock purchase plan	—	—	1,607	—	—	(815,385)	11,653	13,260
Issued pursuant to directors' compensation plan	19,648	—	321	—	—	—	—	321
Stock-based compensation	—	—	37,897	—	—	—	—	37,897
Income tax benefit from equity awards	—	—	241	—	—	—	—	241
Tax withholding – stock compensation	—	—	—	—	—	472,966	(8,125)	(8,125)
Derivative contracts, net	—	—	—	—	70	—	—	70
Net income	—	—	—	525,360	—	—	—	525,360
Balance – December 31, 2012	406,163,194	406	3,136,461	2,434,835	(348)	30,601,262	(456,465)	5,114,889
Stock Repurchase Program	—	—	—	—	—	16,468,648	(277,768)	(277,768)
Issued or purchased pursuant to employee stock compensation plans	3,038,767	3	5,486	—	—	—	—	5,489
Issued pursuant to employee stock purchase plan	—	—	1,844	—	—	(860,901)	13,260	15,104
Issued pursuant to directors' compensation plan	13,612	—	344	—	—	—	—	344
Stock-based compensation	—	—	42,091	—	—	—	—	42,091
Income tax benefit from equity awards	—	—	488	—	—	—	—	488
Tax withholding – stock compensation	—	—	—	—	—	501,887	(8,900)	(8,900)
Derivative contracts, net	—	—	—	—	72	—	—	72
Net income	—	—	—	409,597	—	—	—	409,597
Balance – December 31, 2013	409,215,573	$409	$3,186,714	$2,844,432	$(276)	46,710,896	$(729,873)	$5,301,406

See accompanying Notes to Consolidated Financial Statements.

Note 1. Significant Accounting Policies

Organization and Nature of Operations

Denbury Resources Inc., a Delaware corporation, is a growing, dividend-paying, domestic oil and natural gas company. Our primary focus is on enhanced oil recovery utilizing CO_2, and our operations are focused in two key operating areas: the Gulf Coast and Rocky Mountain regions. Our goal is to increase the value of our acquired properties through a combination of exploitation, drilling and proven engineering extraction practices, with the most significant emphasis relating to tertiary recovery operations.

Principles of Reporting and Consolidation

The consolidated financial statements herein have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP") and include the accounts of Denbury and entities in which we hold a controlling financial interest. Undivided interests in oil and gas joint ventures are consolidated on a proportionate basis. All intercompany balances and transactions have been eliminated.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amount of certain assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during each reporting period. Management believes its estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates. Significant estimates underlying these financial statements include (1) the fair value of financial derivative instruments; (2) the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties, the related present value of estimated future net cash flows therefrom and the ceiling test; (3) the estimated quantities of proved and probable CO_2 reserves used to compute depletion of CO_2 properties; (4) accruals related to oil and natural gas sales volumes and revenues, capital expenditures and lease operating expenses; (5) the estimated costs and timing of future asset retirement obligations; (6) estimates made in the calculation of income taxes; and (7) estimates made in determining the fair values for purchase price allocations, including goodwill. While management is not aware of any significant revisions to any of its estimates, there will likely be future revisions to its estimates resulting from matters such as revisions in estimated oil and natural gas volumes, changes in ownership interests, payouts, joint venture audits, re-allocations by purchasers or pipelines, or other corrections and adjustments common in the oil and natural gas industry, many of which require retroactive application. These types of adjustments cannot be currently estimated and will be recorded in the period in which the adjustment occurs.

Reclassifications

Certain prior period amounts have been reclassified to conform to the current year presentation. Such reclassifications had no impact on our reported net income, current assets, total assets, current liabilities, total liabilities or stockholders' equity.

Cash Equivalents

We consider all highly liquid investments to be cash equivalents if they have maturities of three months or less at the date of purchase.

Restricted Cash

Restricted cash at December 31, 2012 consisted of proceeds from the exchange of oil and gas properties with Exxon Mobil Corporation and its wholly-owned subsidiary, XTO Energy Inc., (see Note 2, *Acquisitions and Divestitures*) previously held by a qualified intermediary and which were restricted for application towards future acquisitions to enable like-kind-exchange transactions for federal income tax purposes, which exchange transactions took place in 2013.

Oil and Natural Gas Properties

Capitalized Costs. We follow the full cost method of accounting for oil and natural gas properties. Under this method, all costs related to acquisitions, exploration and development of oil and natural gas reserves are capitalized and accumulated in a single cost center representing our activities, which are undertaken exclusively in the United States. Such costs include lease acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties, costs of drilling both productive and nonproductive wells, capitalized interest on qualifying projects, and general and administrative expenses directly related to exploration and development activities, and do not include any costs related to production, general corporate overhead or similar activities. We assign the purchase price of oil and natural gas properties we acquire to proved and unevaluated properties based on the estimated fair values as defined in the Financial Accounting Standards Board Codification ("FASC") *Fair Value Measurements and Disclosures* topic. Proceeds received from disposals are credited against accumulated costs except when the sale represents a significant disposal of reserves, in which case a gain or loss would be recognized. A disposal of 25% or more of our proved reserves would be considered significant.

Depletion and Depreciation. The costs capitalized, including production equipment and future development costs, are depleted or depreciated using the unit-of-production method, based on proved oil and natural gas reserves as determined by independent petroleum engineers. Oil and natural gas reserves are converted to equivalent units on a basis of 6,000 cubic feet of natural gas to one barrel of crude oil.

Under full cost accounting, we may exclude certain unevaluated costs from the amortization base pending determination of whether proved reserves can be assigned to such properties. The costs classified as unevaluated are transferred to the full cost amortization base as the properties are developed, tested and evaluated.

Ceiling Test. The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized cost or the cost center ceiling. The cost center ceiling is defined as (1) the present value of estimated future net revenues from proved oil and natural gas reserves before future abandonment costs (discounted at 10%), based on the average first-day-of-the-month oil and natural gas price for each month during the 12-month period prior to the end of a particular reporting period; plus (2) the cost of properties not being amortized; plus (3) the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less (4) related income tax effects. Our future net revenues from proved oil and natural gas reserves are not reduced for development costs related to the cost of drilling for and developing CO_2 reserves nor those related to the cost of constructing CO_2 pipelines, as those costs have previously been incurred by the Company. Therefore, we include in the ceiling test, as a reduction of future net revenues, that portion of our capitalized CO_2 costs related to CO_2 reserves and CO_2 pipelines that we estimate will be consumed in the process of producing our proved oil and natural gas reserves. The fair value of our oil and natural gas derivative contracts is not included in the ceiling test, as we do not designate these contracts as hedge instruments for accounting purposes. The cost center ceiling test is prepared quarterly. We did not have a ceiling test write-down during the years ended December 31, 2013, 2012 or 2011.

Joint Interest Operations. Substantially all of our oil and natural gas exploration and production activities are conducted jointly with others. These financial statements reflect only our proportionate interest in such activities, and any amounts due from other partners are included in trade receivables.

Tertiary Injection Costs. Our tertiary operations are conducted in reservoirs that have already produced significant amounts of oil over many years; however, in accordance with the SEC rules and regulations for recording proved reserves, we cannot recognize proved reserves associated with enhanced recovery techniques, such as CO_2 injection, until there is a production response to the injected CO_2, or unless the field is analogous to an existing flood.

We capitalize, as a development cost, injection costs in fields that are in their development stage, which means we have not yet seen incremental oil production due to the CO_2 injections (i.e., a production response). These capitalized development costs are included in our unevaluated property costs if there are not already proved tertiary reserves in that field. After we see a production response to the CO_2 injections (i.e., the production stage), injection costs are expensed as incurred, and once proved reserves are recognized, previously deferred unevaluated development costs become subject to depletion.

CO_2 Properties

We own and produce CO_2 reserves, a non-hydrocarbon resource, that are used in our tertiary oil recovery operations on our own behalf and on behalf of other interest owners in enhanced recovery fields, with a portion sold to third-party industrial users. We record revenue from our sales of CO_2 to third parties when it is produced and sold. Expenses related to the production of CO_2 are allocated between volumes sold to third parties and volumes consumed internally that are directly related to our tertiary production. The expenses related to third-party sales are recorded in "CO_2 discovery and operating expenses," and the expenses related to internal use are recorded in "Lease operating expenses" in the Consolidated Statements of Operations, or are capitalized as oil and gas properties in our Consolidated Balance Sheets, depending on the stage of the tertiary flood that is receiving the CO_2 (see *Tertiary Injection Costs* above for further discussion).

Costs incurred to search for CO_2 are expensed as incurred until proved or probable reserves are established. Once proved or probable reserves are established, costs incurred to obtain those reserves are capitalized and classified as "CO_2 properties" on our Consolidated Balance Sheets. Capitalized CO_2 costs are aggregated by geologic formation and depleted on a unit-of-production basis over proved and probable reserves.

During 2010 and 2011, we acquired interests in the Riley Ridge Federal Unit ("Riley Ridge"), which contains helium and CO_2 reserves (non-hydrocarbon resources) as well as natural gas reserves (a hydrocarbon resource). It is not possible to separately identify the capitalized costs related to the development of each product in the commingled gas stream; thus, these costs are allocated to each product based on the relative future revenue value of each product line and classified accordingly on the Consolidated Balance Sheets.

The portion of our capitalized CO_2 costs related to CO_2 reserves and CO_2 pipelines that we estimate will be consumed in the process of producing our proved oil reserves is included in the ceiling test as a reduction to future net revenues. The remaining net capitalized CO_2 properties, equipment and pipelines balance is evaluated for impairment by comparing the net carrying costs to the expected future net revenues from (1) the production of our probable and possible tertiary oil reserves and (2) the sale of CO_2 to third-party industrial users.

Pipelines and Plants

CO_2 used in our tertiary floods is transported to our fields through CO_2 pipelines. Costs of CO_2 pipelines under construction are not depreciated until the pipelines are placed into service. Pipelines are depreciated on a straight-line basis over their estimated useful lives, which range from 15 to 50 years.

Pipelines and plants include the Riley Ridge gas processing facility in southwestern Wyoming. We placed the Riley Ridge gas processing facility in service in the fourth quarter of 2013. Individual components of the plant are depreciated on a straight-line basis over their estimated useful lives, which range from 20 to 50 years.

Property and Equipment – Other

Other property and equipment, which includes furniture and fixtures, vehicles, computer equipment and software, and capitalized leases, is depreciated principally on a straight-line basis over each asset's estimated useful life. Vehicles and furniture and fixtures are generally depreciated over a useful life of five to ten years, and computer equipment and software are generally depreciated over a useful life of three to five years. Leasehold improvements are amortized over the shorter of the estimated useful life or the remaining lease term.

Leased property meeting certain capital lease criteria is capitalized, and the present value of the related lease payments is recorded as a liability. Amortization of capitalized leased assets is computed using the straight-line method over the shorter of the estimated useful life or the initial lease term.

Maintenance and repair costs that do not extend the useful life of the property or equipment are charged to expense as incurred.

Asset Retirement Obligations

In general, our future asset retirement obligations relate to future costs associated with plugging and abandoning our oil, natural gas and CO_2 wells, removing equipment and facilities from leased acreage, and returning land to its original condition. The fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred, discounted to its present value using our credit-adjusted-risk-free interest rate, and a corresponding amount capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted each period, and the capitalized cost is depreciated over the useful life of the related asset. Revisions to estimated retirement obligations will result in an adjustment to the related capitalized asset and corresponding liability. If the liability is settled for an amount other than the recorded amount, the difference is recorded to the full cost pool, unless significant.

Asset retirement obligations are estimated at the present value of expected future net cash flows and are discounted using our credit-adjusted-risk-free rate. We utilize unobservable inputs in the estimation of asset retirement obligations that include, but are not limited to, costs of labor and materials, profits on costs of labor and materials, the effect of inflation on estimated costs, and the discount rate. Accordingly, asset retirement obligations are considered a Level 3 measurement under the FASC *Fair Value Measurements and Disclosures* topic.

Commodity Derivative Contracts

We utilize oil and natural gas derivative contracts to mitigate our exposure to commodity price risk associated with our future oil and natural gas production. These derivative contracts have historically consisted of options, in the form of price floors or collars, and fixed price swaps. Our derivative financial instruments are recorded on the balance sheet as either an asset or a liability measured at fair value. We do not apply hedge accounting to our oil and natural gas derivative contracts; accordingly, the changes in the fair value of these instruments are recognized in our Consolidated Statements of Operations in the period of change.

Financial Instruments with Off-Balance-Sheet Risk and Concentrations of Credit Risk

Our financial instruments that are exposed to concentrations of credit risk consist primarily of cash equivalents, trade and accrued production receivables, and the derivative instruments discussed above. Our cash equivalents represent high-quality securities placed with various investment-grade institutions. This investment practice limits our exposure to concentrations of credit risk. Our trade and accrued production receivables are dispersed among various customers and purchasers; therefore, concentrations of credit risk are limited. We evaluate the credit ratings of our purchasers, and if customers are considered a credit risk, letters of credit are the primary security obtained to support lines of credit. We attempt to minimize our credit risk exposure to the counterparties of our oil and natural gas derivative contracts through formal credit policies, monitoring procedures and diversification. All of our derivative contracts are with banks, which are part of the syndicate of banks in our bank credit facility, or with their affiliates. There are no margin requirements with the counterparties of our derivative contracts.

Goodwill and Other Intangible Assets

Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the acquisition of a business. Goodwill is not amortized; rather, it is tested for impairment annually during the fourth quarter and when events or changes in circumstances indicate that it is more likely than not the fair value of a reporting unit with goodwill has been reduced below its carrying value. The impairment test requires allocating goodwill and other assets and liabilities to reporting units. However, we have only one reporting unit. To assess impairment, we have the option to qualitatively assess if it is more likely than not that the fair value of the reporting unit is less than the carrying value. Absent a qualitative assessment, or, through the qualitative assessment, if we determine it is more likely than not that the fair value of the reporting unit is less than the carrying value, a quantitative assessment is prepared to calculate the fair market value of the reporting unit. If it is determined that the fair value of the reporting unit is less than the carrying value, the recorded goodwill is impaired to its implied fair value with a charge to operating expense. We completed our annual goodwill impairment assessment during the fourth quarter of 2013 and did not record any goodwill impairment during 2013, nor have we recorded a goodwill impairment historically.

The following table summarizes the changes in goodwill for the years ended December 31, 2013 and 2012:

	Year Ended December 31,	
In thousands	2013	2012
Beginning of year balance	$1,283,590	$1,236,318
Goodwill related to the Thompson Field acquisition	—	47,272
End of year balance	$1,283,590	$1,283,590

Our intangible assets subject to amortization primarily consist of amounts assigned in purchase accounting to helium production rights at the Riley Ridge Federal Unit in Wyoming and a CO_2 purchase contract with ConocoPhillips to offtake CO_2 from the Lost Cabin gas plant in Wyoming. We amortize our helium production rights on a unit-of-production basis over estimated helium reserves and amortize the CO_2 contract intangible asset on a straight-line basis over the contract term. Total amortization expense related to these assets was $1.3 million during the year ended December 31, 2013. The following table summarizes the intangible asset value and related accumulated amortization as of December 31, 2013 and 2012:

In thousands	Helium Production Rights	CO_2 Purchase Contract	Total
December 31, 2013			
Intangible asset value	$55,266	$33,931	$89,197
Accumulated amortization	—	(1,319)	(1,319)
Net book value as of December 31, 2013	$55,266	$32,612	$87,878
December 31, 2012			
Intangible asset value	$55,266	$33,901	$89,167
Accumulated amortization	—	—	—
Net book value as of December 31, 2012	$55,266	$33,901	$89,167

At December 31, 2013, our estimated amortization expense for our intangible assets subject to amortization over the next five years is as follows:

In thousands	
2014	$2,748
2015	2,843
2016	2,915
2017	2,915
2018	3,568

The recoverability of the carrying amount of intangible assets is assessed whenever events or changes in circumstances indicate that the carrying amount of the asset or asset group may not be recoverable. An impairment loss would be assessed when estimated undiscounted future cash flows from the operation and disposition of the asset group are less than the carrying amount of the asset group. Measurement of an impairment loss is based on the excess of the carrying amount of the asset group over its fair value. Fair value is measured using discounted cash flows or independent appraisals, as appropriate.

Revenue Recognition

Revenue Recognition. Revenue is recognized at the time oil and natural gas is produced and sold. Any amounts due from purchasers of oil and natural gas are included in accrued production receivable.

We follow the sales method of accounting for our oil and natural gas revenue, whereby we recognize revenue on all oil or natural gas sold to our purchasers regardless of whether the sales are proportionate to our ownership in the property. A receivable or liability is recognized only to the extent that we have an imbalance on a specific property greater than the expected remaining proved reserves. As of December 31, 2013 and 2012, our aggregate oil and natural gas imbalances were not material to our consolidated financial statements.

We recognize revenue and expenses of purchased producing properties at the time we assume effective control, commencing from either the closing or purchase agreement date, depending on the underlying terms and agreements. We follow the same methodology in reverse when we sell properties by recognizing revenue and expenses of the sold properties until the closing date.

Significant Oil and Natural Gas Purchasers. Oil and natural gas sales are made on a day-to-day basis or under short-term contracts at the current area market price. We do not expect that the loss of any purchaser would have a material adverse effect upon our operations. For the year ended December 31, 2013, three purchasers accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company (33%), Plains Marketing LP (15%), and Eighty-Eight Oil LLC (10%). For the years ended December 31, 2012 and 2011, two purchasers accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company (39% and 43% in 2012 and 2011, respectively) and Plains Marketing LP (17% and 16% in 2012 and 2011, respectively).

Income Taxes

Income taxes are accounted for using the asset and liability method, under which deferred income taxes are recognized for the future tax effects of temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities using the enacted statutory tax rates in effect at year end. The effect on deferred taxes for a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance for deferred tax assets is recorded when it is more likely than not that the benefit from the deferred tax asset will not be realized.

We recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement.

Net Income Per Common Share

Basic net income per common share is computed by dividing the net income attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted net income per common share is calculated in the same manner, but includes the impact of potentially dilutive securities. Potentially dilutive securities consist of stock options, stock appreciation rights ("SARs"), nonvested restricted stock and nonvested performance equity awards. For each of the three years in the period ended December 31, 2013, there were no adjustments to net income for purposes of calculating basic and diluted net income per common share.

The following is a reconciliation of the weighted average shares used in the basic and diluted net income per common share calculations for the periods indicated:

	Year Ended December 31,		
In thousands	2013	2012	2011
Basic weighted average common shares	366,659	385,205	396,023
Potentially dilutive securities:			
Restricted stock, stock options, SARs and performance-based equity awards	3,218	3,733	4,935
Diluted weighted average common shares	369,877	388,938	400,958

Basic weighted average common shares excludes shares of nonvested restricted stock. As these restricted shares vest, they will be included in the shares outstanding used to calculate basic net income per common share (although all restricted stock is issued and outstanding upon grant). For purposes of calculating diluted weighted average common shares, the nonvested restricted stock is included in the computation using the treasury stock method, with the deemed proceeds equal to the average unrecognized compensation during the period, adjusted for any estimated future tax consequences recognized directly in equity. Stock options and SARs of 3.6 million, 4.1 million and 5.0 million shares for the years ended December 31, 2013, 2012 and 2011, respectively, were not included in the computation of diluted net income per share as their effect would have been antidilutive.

Environmental and Litigation Contingencies

The Company makes judgments and estimates in recording liabilities for contingencies such as environmental remediation or ongoing litigation. Liabilities are recorded when it is both probable that a loss has been incurred and such loss is reasonably estimable. Assessments of liabilities are based on information obtained from independent and in-house experts, loss experience in similar situations, actual costs incurred, and other case-by-case factors. Any related insurance recoveries are recognized in our financial statements during the period received or at the time receipt is determined to be virtually certain.

Recent Accounting Pronouncements

Balance Sheet-Offsetting Assets and Liabilities. In December 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2011-11, *Disclosure about Offsetting Assets and Liabilities* ("ASU 2011-11"). ASU 2011-11 requires an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. In January 2013, the FASB issued ASU 2013-01, *Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities* ("ASU 2013-01"). The update clarifies that the scope of ASU 2011-11 applies to derivatives accounted for in accordance with the *Derivatives and Hedging* topic of the FASC, including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset or subject to an enforceable master netting arrangement or similar agreement. ASU 2011-11 and ASU 2013-01 became effective for our fiscal year beginning January 1, 2013, and have been applied retrospectively for all comparative periods presented. The adoption of ASU 2011-11 and ASU 2013-01 did not affect our consolidated financial statements, but required additional disclosures in the notes thereto.

Note 2. Acquisitions and Divestitures

Fair Value

The FASC *Fair Value Measurements and Disclosures* topic defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (often referred to as the "exit price"). The fair value measurement is based on the assumptions of market participants and not those of the reporting entity. Therefore, entity-specific intentions do not impact the measurement of fair value unless those assumptions are consistent with market participant views.

The fair value of oil and natural gas properties is based on significant inputs not observable in the market, which the FASC *Fair Value Measurements and Disclosures* topic defines as Level 3 inputs. Key assumptions may include (1) NYMEX oil and natural gas futures (this input is observable); (2) dollar-per-acre values of recent sale transactions (this input is observable); (3) projections of the estimated quantities of oil and natural gas reserves, including those classified as proved, probable and possible; (4) estimated oil and natural gas pricing differentials; (5) projections of future rates of production; (6) timing and amount of future development and operating costs; (7) projected costs of CO_2 (to a market participant); (8) projected reserve recovery factors; and (9) risk-adjusted discount rates.

2013 Acquisition

Cedar Creek Anticline Acquisition. In January 2013, we entered into an agreement to acquire producing assets in the Cedar Creek Anticline ("CCA") of Montana and North Dakota from a wholly-owned subsidiary of ConocoPhillips Company ("ConocoPhillips") for $1.05 billion ($1.0 billion after final closing adjustments primarily for revenues and costs of the purchased properties from the January 1, 2013 effective date to the closing date). We closed the acquisition on March 27, 2013, funding the purchase price with a portion of the cash proceeds from the Bakken Exchange Transaction (described below). This acquisition meets the definition of a business under the FASC *Business Combinations* topic. Accordingly, we estimated the fair value of assets acquired and liabilities assumed as of the closing date of the acquisition, using a discounted future net cash flow model.

We finalized our estimate of the fair value of assets acquired and liabilities assumed during 2013, after consideration of final closing adjustments, evaluation of oil and natural gas properties, other assets and related asset retirement obligations. The following table presents a summary of the fair value of assets acquired and liabilities assumed in the CCA acquisition:

In thousands	
Consideration	
Cash consideration (1)	$1,001,707
Fair value of assets acquired and liabilities assumed	
Oil and natural gas properties	
Proved properties	783,507
Unevaluated properties	222,820
Other assets	2,589
Asset retirement obligations	(7,209)
	$1,001,707

(1) See Note 6, *Income Taxes,* for additional information regarding the like-kind-exchange transaction utilized to fund this purchase and Note 13, *Supplemental Cash Flow Information,* for supplemental cash flow information regarding the cash payment.

For the period from March 27, 2013 to December 31, 2013, we recognized $268.3 million of oil, natural gas, and related product sales from the property interests acquired in the CCA acquisition; during that same period, we recognized $194.2 million of net field operating income (defined as oil, natural gas and related product sales less lease operating expenses, production and ad valorem taxes, and marketing expenses) related to the CCA acquisition.

2012 Acquisitions and Divestitures

Bakken Exchange Transaction. In late 2012, we closed a sale and exchange transaction (the "Bakken Exchange Transaction") with Exxon Mobil Corporation and its wholly-owned subsidiary XTO Energy Inc. (collectively, "ExxonMobil") in which we sold to ExxonMobil our Bakken area assets in North Dakota and Montana in exchange for (1) $1.3 billion in cash (after closing adjustments), (2) ExxonMobil's operating interests in Webster Field in Texas and Hartzog Draw Field in Wyoming, and (3) approximately a one-third overriding royalty ownership interest in ExxonMobil's CO_2 reserves in LaBarge Field in Wyoming.

This acquisition meets the definition of a business under the FASC *Business Combinations* topic. We finalized our estimate of the fair value of assets acquired and liabilities assumed during 2013, after consideration of final closing adjustments and evaluation of reserves. The following table presents a summary of the fair value of assets acquired and liabilities assumed in the Bakken Exchange Transaction:

In thousands	
Consideration	
Fair value of net assets transferred	$1,866,107
Less: Fair value of assets acquired and liabilities assumed	
Cash [(1)]	1,277,041
Oil and natural gas properties	
Proved properties	182,289
Unevaluated properties	90,690
CO_2 properties	314,505
Other property and equipment	23,424
Other assets	477
Other liabilities	(8,528)
Asset retirement obligations	(13,791)
Fair value of net assets acquired	$1,866,107

(1) See Note 13, *Supplemental Cash Flow Information,* for additional information regarding the placement of $1.05 billion of the proceeds in a qualified trust in order to enable a like-kind exchange transaction for federal income tax purposes.

Thompson Field Acquisition. In June 2012, we acquired a nearly 100% working interest and 84.7% net revenue interest in Thompson Field for $366.2 million after closing adjustments. The field is located in close proximity to Hastings Field (an enhanced oil recovery field that we are currently flooding with CO_2), which is the current terminus of the Green Pipeline, which transports CO_2 both from the Jackson Dome area near Jackson, Mississippi, and from various anthropogenic sources along the route of the pipeline. Thompson Field is similar to Hastings Field, producing oil from the Frio zone at similar depths, and is also a planned future tertiary field. Under the terms of the Thompson Field acquisition agreement, the seller will retain approximately a 5% gross revenue interest (less severance taxes) once average monthly oil production exceeds 3,000 Bbls/d after the initiation of CO_2 injection.

This acquisition meets the definition of a business under the FASC *Business Combinations* topic. The fair values assigned to assets acquired and liabilities assumed in this acquisition have been finalized, and no adjustments have been made to fair value amounts previously disclosed in our Form 10-K for the period ended December 31, 2012. The following table presents a summary of the fair value of assets acquired and liabilities assumed in the Thompson Field acquisition:

In thousands	
Consideration	
Cash consideration [(1)]	$366,179
Less: Fair value of assets acquired and liabilities assumed	
Oil and natural gas properties	
Proved properties	305,233
Unevaluated properties	12,023
Pipelines and plants	2,000
Other assets	2,957
Asset retirement obligations	(3,306)
	318,907
Goodwill	$ 47,272

(1) See Note 6, *Income Taxes,* for additional information regarding the like-kind-exchange transaction utilized to fund this purchase and Note 13, *Supplemental Cash Flow Information,* for supplemental cash flow information regarding the cash payment.

Unaudited Pro Forma Acquisition Information. The following combined pro forma total revenues and other income and net income are presented as if the previously discussed CCA acquisition, Bakken Exchange Transaction and Thompson Field acquisition had occurred on January 1, 2012:

In thousands, except per-share data	Year Ended December 31, 2013	Year Ended December 31, 2012
Pro forma total revenues and other income	$2,599,301	$2,570,829
Pro forma net income	437,616	582,033
Pro forma net income per common share		
Basic	$ 1.19	$ 1.51
Diluted	1.18	1.50

Other 2012 Divestitures. In April 2012, we completed the sale of certain non-operated assets in the Paradox Basin of Utah for $68.5 million, after final closing adjustments. The sale had an effective date of January 1, 2012. In February 2012, we completed the sale of certain non-core assets primarily located in central and southern Mississippi and in southern Louisiana for net proceeds of $141.8 million, after final closing adjustments. The sale had an effective date of December 1, 2011. We did not record a gain or loss on these divestitures in accordance with the full cost method of accounting. Certain of our 2012 divestitures were structured as like-kind-exchange transactions for federal income tax purposes. See Note 6, *Income Taxes,* for further details.

Note 3. Asset Retirement Obligations

The following table summarizes the changes in our asset retirement obligations for the years ended December 31, 2013 and 2012:

In thousands	Year Ended December 31, 2013	Year Ended December 31, 2012
Beginning asset retirement obligation	$106,430	$ 93,468
Liabilities incurred and assumed during period	22,216	50,956
Revisions in estimated retirement obligations	4,730	5,334
Liabilities settled and sold during period	(15,523)	(50,556)
Accretion expense	8,448	7,228
Ending asset retirement obligation	126,301	106,430
Less: current asset retirement obligation (1)	(6,413)	(3,700)
Long-term asset retirement obligation	$119,888	$102,730

(1) Included in "Accounts payable and accrued liabilities" in our Consolidated Balance Sheets.

Liabilities incurred and assumed generally relate to the drilling of incremental wells and liabilities assumed upon the purchase of additional interests in the CCA during 2013 and the acquisition of Thompson, Webster and Hartzog Draw fields during 2012. Liabilities settled and sold in 2012 include the plugging of old wells in the Tinsley Field and sales of non-core assets located in the Paradox Basin of Utah, Gulf Coast region and Bakken area assets in North Dakota and Montana.

We have escrow accounts that are legally restricted for certain of our asset retirement obligations. The balances of these escrow accounts were $36.0 million and $35.2 million at December 31, 2013 and 2012, respectively. These balances are primarily invested in U.S. Treasury bonds, are recorded at amortized cost and are included in "Other assets" in our Consolidated Balance Sheets. The carrying value of these investments approximates their estimated fair market value at December 31, 2013 and 2012.

Note 4. Property and Equipment

The following table presents a summary of our net property and equipment balances as of December 31, 2013 and 2012:

In thousands	December 31, 2013	December 31, 2012
Oil and natural gas properties		
Proved properties	$ 8,945,326	$ 6,963,211
Unevaluated properties	780,481	809,154
Total	9,725,807	7,772,365
Accumulated depletion and depreciation	(3,219,500)	(2,827,256)
Net oil and natural gas properties	6,506,307	4,945,109
CO_2 properties		
CO_2 properties	1,117,167	1,032,653
Accumulated depletion and depreciation	(150,968)	(119,784)
Net CO_2 properties	966,199	912,869
Pipelines and plants		
CO_2 pipelines (1)	1,681,774	1,632,255
Plants	527,786	402,871
Total	2,209,560	2,035,126
Accumulated depletion and depreciation	(134,697)	(99,185)
Net plants and pipelines	2,074,863	1,935,941
Other property and equipment		
Other property and equipment	466,969	417,207
Accumulated depletion and depreciation	(163,060)	(134,016)
Net other property and equipment	303,909	283,191
Net property and equipment	$ 9,851,278	$ 8,077,110

(1) Amounts include $48.4 million of CO_2 pipelines at December 31, 2013 that were under construction and not subject to depreciation during 2013.

A summary of the unevaluated property costs excluded from oil and natural gas properties being amortized at December 31, 2013, and the year in which the costs were incurred follows:

	December 31, 2013				
	Costs Incurred During:				
In thousands	2013	2012	2011	2010 and Prior	Total
Property acquisition costs	$215,822	$109,275	$12,543	$317,226	$654,866
Exploration and development	41,157	22,080	7,408	10,825	81,470
Capitalized interest	25,222	12,084	6,018	821	44,145
Total	$282,201	$143,439	$25,969	$328,872	$780,481

Our 2013 property acquisition costs were primarily related to the fair value allocated to the purchase of additional interests in the CCA. Our 2012 property acquisition costs were primarily related to the fair value allocated to our Hartzog Draw and Thompson fields. Property acquisition costs for 2010 and prior were primarily related to the fair value allocated to CO_2 tertiary potential at our Cedar Creek Anticline properties, acquired as part of the merger with Encore Acquisition Company (“Encore”), as well as CO_2 tertiary potential at Conroe Field. Exploration and development costs shown as unevaluated properties are primarily associated with our tertiary oil fields that are under development but did not have proved reserves at December 31, 2013. The most significant development costs incurred during 2013, 2012 and 2011 relate to development in preparation for the CO_2 flood at Grieve field, which began in 2013. We have not yet recognized proved reserves in this field.

During 2013, we established proved reserves at Bell Creek Field and, as a result, transferred $417.6 million of costs incurred on these projects into the amortization base. Costs are transferred into the amortization base on an ongoing basis as projects are evaluated and proved reserves established or impairment determined. We review the excluded properties for impairment at least annually. We currently estimate that evaluation of most of these properties and the inclusion of their costs in the amortization base is expected to be completed within five to ten years. Until we are able to determine whether there are any proved reserves attributable to the above costs, we are not able to assess the future impact on the amortization rate of the full cost pool.

Note 5. Long-Term Debt

The following long-term debt and capital lease obligations were outstanding as of December 31, 2013 and 2012:

In thousands	December 31, 2013	December 31, 2012
Bank Credit Agreement	$ 340,000	$ 700,000
9½% Senior Subordinated Notes due 2016, including premium of $9,118	—	234,038
9¾% Senior Subordinated Notes due 2016, including discount of $13,569	—	412,781
8¼% Senior Subordinated Notes due 2020	996,273	996,273
6⅜% Senior Subordinated Notes due 2021	400,000	400,000
4⅝% Senior Subordinated Notes due 2023	1,200,000	—
Other Subordinated Notes, including premium of $16 and $25, respectively	3,823	3,832
Pipeline financings	228,167	236,244
Capital lease obligations	128,519	158,260
Total	3,296,782	3,141,428
Less: current obligations	(36,157)	(36,966)
Long-term debt and capital lease obligations	$ 3,260,625	$ 3,104,462

The ultimate parent company in our corporate structure, Denbury Resources Inc. ("DRI"), is the sole issuer of all of our outstanding senior subordinated notes. DRI has no independent assets or operations. Each of the subsidiary guarantors of such notes is 100% owned, directly or indirectly, by DRI; any subsidiaries of DRI other than the subsidiary guarantors are minor subsidiaries, and the guarantees of the notes are full and unconditional and joint and several.

$1.6 Billion Revolving Credit Agreement

In March 2010, we entered into a $1.6 billion revolving credit agreement with JPMorgan Chase Bank, N.A. ("JPMorgan"), as administrative agent, and other lenders party thereto (as amended, the "Bank Credit Agreement"). Availability under the Bank Credit Agreement is subject to a borrowing base, which is redetermined semi-annually on or prior to May 1 and November 1 of each year, and additionally upon requested special redeterminations. The borrowing base is adjusted at the lenders' discretion and is based in part upon external factors over which we have no control (including approval by the lenders party to the Bank Credit Agreement). If our outstanding credit under the Bank Credit Agreement exceeds the then effective borrowing base, we would be required to repay the excess amount over a period not to exceed four months. As part of the semi-annual review completed in October 2013 pursuant to the terms of the Bank Credit Agreement, our borrowing base was reaffirmed at $1.6 billion effective November 1, 2013, with approval by all of the lenders. The weighted average interest rate on borrowings outstanding as of December 31, 2013 under the Bank Credit Agreement was 1.9%. Loans under the Bank Credit Agreement mature in May 2016.

The Bank Credit Agreement is secured by substantially all of the proved oil and natural gas properties of DRI's restricted subsidiaries (which does not include minor subsidiaries) and by the equity interests of such restricted subsidiaries. In addition, our obligations under the Bank Credit Agreement are guaranteed jointly and severally by DRI's restricted subsidiaries.

The Bank Credit Agreement contains several restrictive covenants including, among others:

- a requirement to maintain a current ratio, as determined under the Bank Credit Agreement, of not less than 1.0 to 1.0;
- a requirement to maintain a maximum permitted ratio of consolidated total debt to Consolidated EBITDA (as defined in the Bank Credit Agreement) of DRI and its restricted subsidiaries of not more than 4.25 to 1.0;
- a prohibition against incurring debt, subject to permitted exceptions; and
- a limitation on the aggregate amount of forecasted oil and natural gas production that can be economically hedged with oil or natural gas derivative contracts.

Under the Bank Credit Agreement, we are permitted to make unlimited distributions in the form of repurchases of Denbury common stock and payments of cash dividends on Denbury common stock, provided that (1) prior to and after making any such distribution (a) no default or borrowing base deficiency exists, and (b) we are in compliance with the first two financial covenants described immediately above (calculated on a pro forma basis after giving effect to the making of any such distribution), and (2) we have minimum availability of at least 10% of our borrowing base on the date such distribution is made.

Loans under the Bank Credit Agreement are subject to varying rates of interest based on (1) the total outstanding credit in relation to the borrowing base and (2) whether the loan is a Eurodollar loan or a base rate loan. Eurodollar loans bear interest at the Adjusted Eurodollar Rate (as defined in the Bank Credit Agreement) plus the applicable margin in a range from 1.5% to 2.5% based on the ratio of outstanding credit to the borrowing base, and base rate loans bear interest at the Base Rate (as defined in the Bank Credit Agreement) plus the applicable margin in a range from 0.5% to 1.5% based on the ratio of outstanding credit to the borrowing base. The "Eurodollar rate" for any interest period (either one, two, three, six, and, if available to all lenders, nine or twelve months, as selected by us) is the rate per year equal to LIBOR, as published by Reuters or another source designated by JPMorgan, for deposits in dollars for a similar interest period. The "base rate" is calculated as the highest of (1) the annual rate of interest announced by JPMorgan as its "prime rate," (2) the federal funds effective rate plus 0.5%, and (3) the Adjusted Eurodollar Rate (as defined in the Bank Credit Agreement) for a one-month interest period plus 1.0%. We incur a commitment fee of either 0.375% or 0.5%, based on the ratio of outstanding credit to the borrowing base, on the unused availability under the Bank Credit Agreement.

Senior Subordinated Notes

Repurchase and Redemption of 9½% Notes and 9¾% Notes. In January 2013, we commenced cash tender offers to purchase the outstanding $426.4 million principal amount of our 9¾% Senior Subordinated Notes due 2016 (the "9¾% Notes") at 105.425% of par and the outstanding $224.9 million principal amount of our 9½% Senior Subordinated Notes due 2016 (the "9½% Notes") at 106.869% of par. During February 2013, we accepted for purchase $191.7 million principal amount of the outstanding 9¾% Notes and $186.7 million principal amount of the outstanding 9½% Notes. The purchases under these tender offers were funded by a portion of the proceeds received in February 2013 from the issuance of our 4⅝% Senior Subordinated Notes due 2023 (the "2023 Notes"). In March 2013, we repurchased all of the remaining $234.7 million principal amount outstanding of our 9¾% Notes at 104.875% of par. In May 2013, we repurchased all of the remaining $38.2 million principal amount outstanding of our 9½% Notes at 104.75% of par.

We recognized a loss associated with the debt repurchases of $44.7 million during the year ended December 31, 2013, consisting of both premium payments made to repurchase or redeem the 9¾% Notes and 9½% Notes and the elimination of unamortized debt issuance costs, discounts and premiums related to these notes. The loss is included in our Consolidated Statement of Operations under the caption "Loss on early extinguishment of debt".

8¼% Senior Subordinated Notes due 2020. In February 2010, we issued $1.0 billion of 8¼% Senior Subordinated Notes due 2020 (the "2020 Notes") for net proceeds after underwriting discounts and commissions of $980 million. The 2020 Notes, which carry a coupon rate of 8.25%, were sold at par. We subsequently redeemed $3.7 million principal amount of the 2020 Notes, as required under the indenture governing the 2020 Notes.

The 2020 Notes mature on February 15, 2020, and interest is payable on February 15 and August 15 of each year. We may redeem the 2020 Notes in whole or in part at our option beginning February 15, 2015, at a redemption price of 104.125% of the principal amount, and at declining redemption prices thereafter, as specified in the indenture. Prior to February 15, 2015, we may redeem 100% of the principal amount of the 2020 Notes at a price equal to 100% of the principal amount plus a "make-whole" premium and accrued and unpaid interest. The 2020 Notes are not subject to any sinking fund requirements.

6⅜% Senior Subordinated Notes due 2021. In February 2011, we issued $400 million of 6⅜% Senior Subordinated Notes due 2021 ("2021 Notes"). The 2021 Notes, which carry a coupon rate of 6.375%, were sold at par. The net proceeds of $393 million were used to repurchase a portion of our 7½% Senior Subordinated Notes due 2013 (the "2013 Notes") and 7½% Senior Subordinated Notes due 2015 (the "2015 Notes") (see *2011 Redemption of 2013 Notes and 2015 Notes* below).

The 2021 Notes mature on August 15, 2021, and interest is payable on February 15 and August 15 of each year. We may redeem the 2021 Notes in whole or in part at our option beginning August 15, 2016 at a redemption price of 103.188% of the principal amount, and at declining redemption prices thereafter, as specified in the indenture. Prior to August 15, 2014, we may at our option redeem up to an aggregate of 35% of the principal amount of the 2021 Notes at a price of 106.375% of par with the proceeds of certain equity offerings. In addition, at any time prior to August 15, 2016, we may redeem 100% of the principal amount of the 2021 Notes at a price equal to 100% of the principal amount plus a "make-whole" premium and accrued and unpaid interest. The 2021 Notes are not subject to any sinking fund requirements.

4⅝% Senior Subordinated Notes due 2023. In February 2013, we issued $1.2 billion of 2023 Notes. The 2023 Notes, which carry a coupon rate of 4.625%, were sold at par. The net proceeds, after issuance costs, of $1.18 billion were used to repurchase or redeem our 9½% Notes and 9¾% Notes (see *Repurchase and Redemption of 9½% Notes and 9¾% Notes* above) and to pay down a portion of outstanding borrowings under our Bank Credit Agreement.

The 2023 Notes mature on July 15, 2023, and interest is payable on January 15 and July 15 of each year, commencing July 15, 2013. We may redeem the 2023 Notes in whole or in part at our option beginning January 15, 2018, at a redemption price of 102.313% of the principal amount, and at declining redemption prices thereafter, as specified in the indenture. Prior to January 15, 2016, we may at our option redeem up to an aggregate of 35% of the principal amount of the 2023 Notes at a redemption price of 104.625% of par with the proceeds of certain equity offerings. In addition, at any time prior to January 15, 2018, we may redeem 100% of the principal amount of the 2023 Notes at a redemption price equal to 100% of the principal amount plus a "make-whole" premium and accrued and unpaid interest.

Restrictive Covenants in Indentures for Senior Subordinated Notes. Each of the indentures for the 2020 Notes, 2021 Notes and 2023 Notes contains certain covenants which are generally consistent and which restrict our ability and the ability of our restricted subsidiaries to take or permit certain actions, including restrictions on our ability and the ability of our restricted subsidiaries to (1) incur additional debt; (2) make investments; (3) create liens on our assets or the assets of our restricted subsidiaries; (4) create restrictions on the ability of our restricted subsidiaries to pay dividends or make other payments to DRI or other restricted subsidiaries; (5) engage in transactions with our affiliates; (6) transfer or sell assets or subsidiary stock; (7) consolidate, merge or transfer all or substantially all of our assets and the assets of our restricted subsidiaries; and (8) make restricted payments (which includes paying dividends on our common stock or redeeming, repurchasing or retiring such stock or subordinated debt), provided that the restricted payments covenant in the indenture for the 2023 Notes (the "2023 Indenture") permits us in certain circumstances to make unlimited restricted payments so long as we maintain a ratio of total debt to EBITDA (both as defined in the 2023 Indenture) of at least 2.5 to 1 (both before and after giving effect to any restricted payment), although we will not be able to realize the practical benefit of the restricted payment covenant flexibility in the 2023 Indenture until the 2020 Notes and 2021 Notes have been redeemed or retired.

2011 Redemption of 2013 Notes and 2015 Notes. Pursuant to cash tender offers, during 2011 we repurchased $225 million in principal of our 2013 Notes and $300 million in principal of our 2015 Notes. We recognized a $16.1 million loss during the year ended December 31, 2011 associated with the debt repurchases, which is included in our Consolidated Statement of Operations under the caption "Loss on early extinguishment of debt".

Pipeline Financings

In May 2008, we closed two transactions with Genesis Energy, L.P. ("Genesis") involving two of our pipelines. The NEJD Pipeline system included a 20-year financing lease, and the Free State Pipeline included a long-term transportation service agreement. We recorded both of these transactions as financing leases.

Debt Issuance Costs

In connection with the issuance of our outstanding long-term debt, we have incurred debt issuance costs, which are being amortized to interest expense using the effective interest method over the term of each related facility. Remaining unamortized debt issuance costs were $58.9 million and $56.5 million at December 31, 2013 and 2012, respectively. These balances are included in "Other assets" in our Consolidated Balance Sheets.

Indebtedness Repayment Schedule

At December 31, 2013, our indebtedness, including our capital and financing lease obligations but excluding the discount and premium on our senior subordinated debt, is payable over the next five years and thereafter as follows:

In thousands	
2014	$ 36,156
2015	37,634
2016	377,933
2017	36,855
2018	31,899
Thereafter	2,776,288
Total indebtedness	$3,296,765

Note 6. Income Taxes

Our income tax provision (benefit) is as follows:

	Year Ended December 31,		
In thousands	2013	2012	2011
Current income tax expense (benefit)			
Federal	$ 393	$ 57,720	$ (12,552)
State	9,864	18,034	20,801
Total current income tax expense	10,257	75,754	8,249
Deferred income tax expense (benefit)			
Federal	222,559	239,862	329,715
State	(33)	15,881	12,748
Total deferred income tax expense	222,526	255,743	342,463
Total income tax expense	$232,783	$331,497	$350,712

For federal income tax purposes, we structured the 2012 divestitures of our Bakken area assets and certain non-core assets as like-kind-exchange transactions for interests acquired in Thompson, Webster, Hartzog Draw and LaBarge fields in 2012 and the CCA Acquisition in 2013 (see Note 2, *Acquisitions and Divestitures*), thereby deferring the majority of the taxable gain on those divestitures. The increase in current taxes during 2012 is primarily due to the taxable gain recognized in the Bakken Exchange Transaction that we were unable to defer through a like-kind-exchange transaction.

At December 31, 2013, we had tax-effected federal net operating loss carryforwards ("NOLs") totaling $20.2 million, state NOLs totaling $41.4 million, an estimated $15.0 million of enhanced oil recovery credits to carry forward related to our tertiary operations, and $34.8 million of alternative minimum tax credits. Our state NOLs expire in various years, starting in 2018, although most do not begin to expire until 2024. Our enhanced oil recovery credits will begin to expire in 2025.

At December 31, 2013, we had $13.0 million of excess tax benefits related to stock-based compensation that was not recorded as an increase to additional paid-in capital in the period that the stock award vested and/or was exercised. At the time these excess tax benefits reduce current taxes payable and thus, are deemed to be realized by the Company, a corresponding increase to additional paid-in capital will be recognized.

Deferred income taxes reflect the available tax carryforwards and the temporary differences based on tax laws and statutory rates in effect at the December 31, 2013 and 2012 balance sheet dates. We believe that we will be able to realize all of our deferred tax assets at December 31, 2013, and therefore, have provided no valuation allowance against our deferred tax assets.

Significant components of our deferred tax assets and liabilities as of December 31, 2013 and 2012 are as follows:

In thousands	December 31, 2013	December 31, 2012
Deferred tax assets		
Loss carryforwards – federal	$ 20,247	$ —
Loss carryforwards – state	41,379	35,007
Tax credit carryover	34,837	34,837
Derivative contracts	21,341	7,252
Enhanced oil recovery credit carryforwards	14,974	17,346
Stock-based compensation	34,635	28,387
Other	37,679	37,226
Total deferred tax assets	205,092	160,055
Deferred tax liabilities		
Property and equipment	(2,541,426)	(2,277,388)
Other	(10,206)	(6,963)
Total deferred tax liabilities	(2,551,632)	(2,284,351)
Total net deferred tax liability	$(2,346,540)	$(2,124,296)

Our reconciliation of income tax expense computed by applying the U.S. federal statutory rate and the reported effective tax rate on income from continuing operations is as follows:

In thousands	Year Ended December 31, 2013	2012	2011
Income tax provision calculated using the federal statutory income tax rate	$224,833	$299,900	$323,416
State income taxes, net of federal income tax benefit	13,518	30,955	29,555
Effect of statutory rate change	(4,178)	(429)	(578)
Other	(1,390)	1,071	(1,681)
Total income tax expense	$232,783	$331,497	$350,712

We file consolidated and separate income tax returns in the U.S. federal jurisdiction and in many state jurisdictions. Our income tax returns for tax years ending 2010 through 2012 currently remain subject to examination by the appropriate taxing authorities. We have not paid any significant interest or penalties associated with our income taxes.

Note 7. Stockholders' Equity

Stock Repurchase Program

In October 2011, we commenced a common share repurchase program for up to $500 million of Denbury common shares, as approved by the Company's Board of Directors. During 2012 and 2013, the Board of Directors increased the dollar amount of Denbury common shares that could be purchased under the program to an aggregate of $1.162 billion. The program has no pre-established ending date and may be suspended or discontinued at any time. We are not obligated to repurchase any dollar amount or specific number of shares of our common stock under the program. The following table presents a summary of repurchases under our share repurchase program:

Dollar amounts in thousands, except per-share data	Total Repurchases Since Inception	Year Ended December 31, 2013	2012	2011
Total amount repurchased	$ 739,652	$ 277,768	$ 266,657	$ 195,227
Weighted average price per share	$ 15.55	$ 16.87	$ 15.71	$ 13.83
Denbury common stock repurchased (shares)	47,559,266	16,468,648	16,978,008	14,112,610

As of December 31, 2013, we were authorized to repurchase an additional $422.3 million of common stock under this repurchase program. We account for treasury stock using the cost method and include treasury stock as a component of stockholders' equity. See Note 14, *Subsequent Events,* for additional information.

Employee Stock Purchase Plan

We have an Employee Stock Purchase Plan that is authorized to issue up to 11,900,000 shares of common stock. As of December 31, 2013, there were 1,601,230 authorized shares remaining to be issued under the plan. In accordance with the plan, eligible employees may contribute up to 10% of their base salary, and we match 75% of their contribution. The combined funds are used to purchase previously unissued Denbury common stock or treasury stock that we purchased in the open market for that purpose, in either case, based on the market value of our common stock at the end of each quarter. We recognize compensation expense for the 75% Company match portion, which totaled $6.5 million, $5.7 million and $4.8 million for the years ended December 31, 2013, 2012 and 2011, respectively. This plan is administered by the Compensation Committee of our Board of Directors.

401(k) Plan

We offer a 401(k) plan to which employees may contribute tax-deferred earnings subject to IRS limitations. We match 100% of an employee's contribution, up to 6% of compensation, as defined by the plan, which is vested immediately. During 2013, 2012 and 2011, our matching contributions to the 401(k) Plan were approximately $9.0 million, $8.0 million and $7.1 million, respectively.

Note 8. Stock Compensation Plans

Stock Incentive Plans

We have two stock compensation plans. The first plan (providing only for the issuance of stock options) has been in existence since 1995 (the "1995 Plan") and expired in August 2005 (although options granted under the 1995 Plan prior to that time can remain outstanding for up to 10 years). The second plan, the 2004 Omnibus Stock and Incentive Plan (the "2004 Plan"), was approved by the stockholders in May 2004 and will expire in May 2024. The 2004 Plan provides for the issuance of incentive and non-qualified stock options, restricted stock awards, restricted stock units, SARs settled in stock, and performance awards that may be issued to officers, employees, directors and consultants. Awards covering a total of 34.5 million shares of common stock have been authorized for issuance pursuant to the 2004 Plan, of which awards covering no more than 27.2 million shares may be issued in the form of restricted stock or performance-vesting awards. At December 31, 2013, 10.8 million shares were available under the 2004 Plan for future issuance of awards, all of which could be issued in the form of restricted stock or performance vesting awards. Our incentive compensation program is administered by the Compensation Committee of our Board of Directors.

Prior to January 1, 2006, we granted incentive and non-qualified stock options to our employees. Effective January 1, 2006, we completely replaced the use of stock options for employees with SARs settled in stock, as SARs are less dilutive to our stockholders while providing an employee with essentially the same economic benefits as stock options. The stock options and SARs generally become exercisable over a three- or four-year vesting period, with the specific terms of vesting determined at the time of grant based on guidelines established by the Compensation Committee of the Board of Directors. The stock options and SARs expire over terms not to exceed 10 years from the date of grant, 90 days after termination of employment, 90 days or one year after permanent disability, depending on the plan, or one year after the death of the optionee. The stock options and SARs are granted at the fair market value at the time of grant, which is defined in the 2004 Plan as the closing price on the NYSE on the date of grant.

Holders of restricted stock awards have the rights and privileges of owning the shares (including voting rights) except that the holders are not entitled to delivery of a portion thereof until certain requirements are met. Beginning in 2014, restricted stock awards granted by the Company provide the holders with forfeitable dividend rights until the award vests. Restricted stock awards vest over three-to-four-year vesting periods, with the specific terms of vesting determined at the time of grant.

Annually, the Board of Directors grants performance-based equity awards to officers of Denbury. These performance-based awards generally vest over 1.25 to 3.25 years and the number of performance-based shares earned (and eligible to vest) during the performance period will depend upon two sets of factors: (1) our level of success in achieving specifically identified performance targets ("Performance-based Operational Awards") and (2) performance of our stock relative to that of a designated peer group ("Performance-based TSR Awards"). Generally, one-half of the maximum number of shares that could be earned under the performance-based awards will be earned for performance at the designated target levels (100% target vesting levels) or upon any earlier change of control, and twice the number of shares will be earned if the maximum target levels are met. If performance is below the designated minimum levels for all performance targets, no performance-based shares will be earned. Performance-based Operational Awards are valued using the fair market value of Denbury stock on the grant date, and Performance-based TSR Awards are valued using a Monte Carlo simulation.

Stock-based compensation expense associated with our field employees is included in "Lease operating expense," while such expense associated with non-field employees is included in "General and administrative expenses" in the Consolidated Statements of Operations. Stock-based compensation associated with our employees involved in exploration and drilling activities is capitalized as part of "Oil and natural gas properties" in the Consolidated Balance Sheets.

Stock-based compensation costs for the years ended December 31, 2013, 2012 and 2011, are as follows:

	Year Ended December 31,		
In thousands	2013	2012	2011
Stock-based compensation expensed:			
General and administrative expenses	$30,429	$26,463	$30,256
Lease operating expenses	2,574	2,847	2,621
Other expenses	—	—	313
Total stock-based compensation expensed	33,003	29,310	33,190
Stock-based compensation capitalized	9,088	8,587	6,998
Total cost of stock-based compensation arrangements	$42,091	$37,897	$40,188
Income tax benefit recognized for stock-based compensation arrangements	$12,541	$11,284	$12,612

Stock Options and SARs

The fair value of each SAR award is estimated on the date of grant using the Black-Scholes option pricing model with the assumptions noted in the following table. The risk-free rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the time of grant. The expected life of stock options and SARs granted was derived from examination of our historical option grants and subsequent exercises. The contractual terms (cliff vesting and graded vesting) are evaluated separately for the expected life, as the exercise behavior for each is different. Expected volatilities are based on the historical volatility of our common stock. Implied volatility was not used in this analysis, as our tradable call option terms are short and the trading volume is low.

	2013	2012	2011
Weighted average fair value of SARs granted	$6.72	$8.90	$9.68
Risk-free interest rate	0.67%	0.79%	1.74%
Expected life	3.6 to 4.8 years	4.0 to 5.0 years	4.0 to 5.0 years
Expected volatility	50.4%	64.9%	63.3%
Dividend yield	—%	—%	—%

The following is a summary of our stock option and SAR activity:

	Number of Awards	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at December 31, 2012	10,445,135	$14.75		
Granted	720,859	16.95		
Exercised	(1,970,426)	9.33		
Forfeited	(113,509)	17.31		
Expired	(95,144)	22.74		
Outstanding at December 31, 2013	8,986,915	16.00	3.3	$19,319
Exercisable at end of period	6,632,141	$15.51	2.7	$18,970

The following is a summary of the total intrinsic value of stock options and SARs exercised and grant-date fair value of stock options and SARs vested:

	Year Ended December 31,		
In thousands	2013	2012	2011
Intrinsic value of stock options exercised	$17,287	$17,315	$20,463
Grant-date fair value of stock options and SARs vested	12,852	26,391	11,416

As of December 31, 2013, there was $8.0 million of total compensation cost to be recognized in future periods related to nonvested stock option and SAR share-based compensation arrangements. The cost is expected to be recognized over a weighted-average period of 1.7 years. The following is a summary of cash received from stock option exercises under share-based payment arrangements and tax benefits realized from the exercises of stock options and SARs:

	Year Ended December 31,		
In thousands	2013	2012	2011
Cash received from stock option exercises	$5,487	$6,022	$4,685
Tax benefit realized for the exercises of stock options and SARs	437	458	539

Restricted Stock – 2004 Plan

As of December 31, 2013, there was $30.6 million of unrecognized compensation expense related to nonvested restricted stock grants. This unrecognized compensation cost is expected to be recognized over a weighted-average period of 2.1 years. The following is a summary of the total vesting date fair value of restricted stock under the 2004 Plan:

	Year Ended December 31,		
In thousands	2013	2012	2011
Fair value of restricted stock vested	$21,529	$22,332	$12,355

A summary of the status of our nonvested restricted stock grants issued under our 2004 Plan and the changes during the year ended December 31, 2013 is presented below:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at December 31, 2012	3,406,207	$15.60
Granted	1,805,467	16.96
Vested	(1,310,347)	16.21
Forfeited	(165,917)	17.23
Nonvested at December 31, 2013	3,735,410	15.97

Restricted Stock – Legacy Encore Plan

In February 2010, prior to the consummation of the merger with Encore, Encore issued a restricted stock grant to its employees under the Encore Acquisition Company 2008 Incentive Stock Plan ("Encore Plan"). At the time of the merger with Encore, the shares were converted into shares of Denbury restricted stock. The shares vest ratably over a four-year graded vesting period; however, legacy Encore employees who terminated their employment for Good Reason, as defined by Encore's legacy Employee Severance Protection Plan, automatically vested in their awards upon termination. The remaining nonvested restricted stock issued under the Encore Plan is scheduled to vest during the first quarter of 2014. The following is a summary of the total vesting date fair value of restricted stock under the Encore Plan:

	Year Ended December 31,		
In thousands	2013	2012	2011
Fair value of restricted stock vested	$512	$584	$2,259

A summary of the status of the non-vested restricted stock grants under the Encore Plan and the changes during the year ended December 31, 2013 is presented below:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at December 31, 2012	56,258	$15.43
Vested	(31,140)	15.43
Forfeited	(3,377)	15.43
Nonvested at December 31, 2013	21,741	15.43

Performance-Based Equity Awards

During 2013 and 2012, we granted Performance-Based Operational Awards and Performance-Based TSR Awards to our officers. As of December 31, 2013, there was $5.4 million of unrecognized compensation expense related to nonvested performance-based equity awards. This unrecognized compensation cost is expected to be recognized over a weighted-average period of 1.6 years. The range of assumptions used in the Monte Carlo simulation valuation approach for Performance-based TSR Awards, which were granted for the first time during 2012, are as follows:

	December 31,	
	2013	2012
Weighted average fair value of Performance-based TSR Award granted	$20.08	$24.68
Risk-free interest rate	0.41%	0.42%
Expected life	3.0 years	2.8 years
Expected volatility	42.3%	45.2%
Dividend yield	—%	—%

A summary of the status of the nonvested performance-based equity awards (presented at the target level) during the year ended December 31, 2013 is as follows:

	Performance-Based Operational Awards		Performance-Based TSR Awards	
	Number of Awards	Weighted Average Grant-Date Fair Value	Number of Awards	Weighted Average Grant-Date Fair Value
Nonvested at December 31, 2012	100,193	$17.27	86,917	$ 24.68
Granted	215,258	16.77	209,474	20.08
Vested (1)	(100,193)	17.27	—	—
Forfeited	(5,784)	16.77	—	—
Nonvested at December 31, 2013	209,474	16.77	296,391	21.43

(1) During 2013, the 2012 annual Performance-based Operational Awards vested, and award holders received shares equivalent to 136% of the number of target-level shares.

The following is a summary of the total vesting date fair value of performance-based equity awards:

In thousands	Year Ended December 31, 2013	2012	2011
Vesting date fair value of Performance-based Operational Awards	$2,541	$2,191	$10,892

Note 9. Commodity Derivative Contracts

We do not apply hedge accounting treatment to our oil and natural gas derivative contracts; therefore, the changes in the fair values of these instruments are recognized in income in the period of change. These fair value changes, along with the cash settlements of expired contracts, are shown under "Commodity derivatives expense (income)" in our Consolidated Statements of Operations.

From time to time, we enter into various oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production. We do not hold or issue derivative financial instruments for trading purposes. These contracts have consisted of price floors, collars and fixed price swaps. The production that we hedge has varied from year to year depending on our levels of debt and financial strength and expectation of future commodity prices. We currently employ a strategy to hedge a portion of our forecasted production approximately 18 months to two years in the future from the current quarter, as we believe it is important to protect our future cash flow to provide a level of assurance for our capital spending in those future periods in light of current worldwide economic uncertainties and commodity price volatility.

We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures, and diversification, and all of our commodity derivative contracts are with parties that are lenders under our Bank Credit Agreement. As of December 31, 2013, all of our outstanding derivative contracts were subject to enforceable master netting arrangements whereby payables on those contracts can be offset against receivables from separate derivative contracts with the same counterparty. It is our policy to classify derivative assets and liabilities on a gross basis on our balance sheets, even if the contracts are subject to enforceable master netting arrangements.

The following table summarizes our commodity derivative contracts, none of which are classified as hedging instruments:

					Contract Prices (1)			
						Weighted Average Price		
Year	Months	Type of Contract	Pricing Index	Volume (2)	Range	Swap	Floor	Ceiling
Oil Contracts:								
2014	Jan – Mar	Swap	NYMEX	58,000	$ 91.67 – 95.95	$93.53	$ —	$ —
	Apr – June	Swap	NYMEX	58,000	91.67 – 95.95	93.53	—	—
	July – Sept	Swap	NYMEX	58,000	90.00 – 93.50	92.52	—	—
	Oct – Dec	Swap	NYMEX	58,000	90.00 – 93.50	92.52	—	—
2015	Jan – Mar	Collar	NYMEX	38,000	$ 80.00 – 100.90	$ —	$80.00	$ 96.96
	Jan – Mar	Collar	LLS	20,000	85.00 – 104.00	—	85.00	101.45
	Apr – June	Collar	NYMEX	38,000	80.00 – 95.25	—	80.00	94.62
	Apr – June	Collar	LLS	20,000	85.00 – 103.00	—	85.00	102.01
	July – Sept	Collar	NYMEX	38,000	80.00 – 95.25	—	80.00	95.04
	July – Sept	Collar	LLS	20,000	85.00 – 102.60	—	85.00	100.69
Natural Gas Contracts:								
2014	Jan – Dec	Collar	NYMEX	14,000	$ 4.00 – 4.47	$ —	$ 4.00	$ 4.45

(1) Contract prices are stated in $/Bbl and $/MMBtu for oil and natural gas contracts, respectively.

(2) Contract volumes are stated in Bbl/d and MMBtu/d for oil and natural gas contracts, respectively.

Note 10. Fair Value Measurements

The FASC *Fair Value Measurements and Disclosures* topic defines fair value as the price that would be received to sell an asset or would be paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We are able to classify fair value balances based on the observability of those inputs. The FASC establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

- Level 1 — Quoted prices in active markets for identical assets or liabilities as of the reporting date.
- Level 2 — Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reported date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. Instruments in this category include non-exchange-traded oil and natural gas derivatives that are based on NYMEX pricing. Our swap contracts are valued using a discounted cash flow model based upon forward commodity price curves. Our costless collars are valued using the Black-Scholes model, an industry standard option valuation model that takes into account inputs such as contractual prices for the underlying instruments, including maturity, quoted forward prices for commodities, interest rates, volatility factors and credit worthiness, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.
- Level 3 — Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. At December 31, 2013, instruments in this category include non-exchange-traded oil collars that are based on regional pricing other than NYMEX (i.e., Louisiana Light Sweet). Our costless collars are valued using the Black-Scholes model, which is described above. We obtain and ensure the appropriateness of the significant inputs to the calculation, including contractual prices for the underlying instruments, maturity, forward prices for commodities, interest rates, volatility factors and credit worthiness, and the fair value estimate is prepared and reviewed on a quarterly basis. Implied volatilities utilized in the valuation of Level 3 instruments are developed using a benchmark, which is considered a significant unobservable input. A one percent increase or decrease in implied volatility would result in a change of approximately $0.1 million in the fair value of these instruments as of December 31, 2013.

We adjust the valuations from the valuation model for nonperformance risk, using our estimate of the counterparty's credit quality for asset positions and our credit quality for liability positions. We use multiple sources of third-party credit data in determining counterparty nonperformance risk, including credit default swaps.

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2013 and 2012:

In thousands	Fair Value Measurements Using: Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
December 31, 2013				
Assets:				
Oil and natural gas derivative contracts – current	$ —	$ 5	$ —	$ 5
Oil and natural gas derivative contracts – long-term	—	3,034	6,908	9,942
Total Assets	$ —	$ 3,039	$ 6,908	$ 9,947
Liabilities:				
Oil and natural gas derivative contracts – current	$ —	$(53,822)	$ —	$(53,822)
Oil and natural gas derivative contracts – long-term	—	(3,214)	(199)	(3,413)
Total Liabilities	$ —	$ (57,036)	$ (199)	$ (57,235)
December 31, 2012				
Assets:				
Oil and natural gas derivative contracts – current	$ —	$ 19,477	$ —	$ 19,477
Oil and natural gas derivative contracts – long-term	—	36	—	36
Total Assets	$ —	$ 19,513	$ —	$ 19,513
Liabilities:				
Oil and natural gas derivative contracts – current	$ —	$ (2,659)	$ —	$ (2,659)
Oil and natural gas derivative contracts – long-term	—	(23,781)	—	(23,781)
Total Liabilities	$ —	$(26,440)	$ —	$(26,440)

The following table summarizes the changes in the fair value of our Level 3 assets and liabilities for the years ended December 31, 2013 and 2012:

In thousands	December 31, 2013	2012
Fair value of Level 3 instruments, beginning of year	$ —	$ 23,950
Fair value adjustments on commodity derivatives	6,709	3,921
Receipt on settlements of commodity derivatives	—	(27,871)
Fair value of Level 3 instruments, end of year	$6,709	$ —
The amount of total gains for the period included in earnings attributable to the change in unrealized gains relating to assets still held at the reporting date	$6,709	$ —

Since we do not use hedge accounting for our commodity derivative contracts, any gains and losses on our assets and liabilities are included in "Commodity derivatives expense (income)" in the accompanying Consolidated Statements of Operations.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

During 2012, we recorded a $15.1 million impairment charge for an investment in the preferred stock of an entity that was created to develop a gasification plant (in which we would offtake its CO_2 to use in our tertiary oil operations) as a result of this project not moving forward. This charge is classified as "Impairment of assets" in the Consolidated Statement of Operations for the year ended December 31, 2012.

Other Fair Value Measurements

The carrying value of our revolving bank credit facility approximates fair value, as it is subject to short-term floating interest rates that approximate the rates available to us for those periods. We use a market approach to determine fair value of our fixed-rate debt using observable market data. The fair values of our senior subordinated notes are based on quoted market prices. The estimated fair value of our total long-term debt as of December 31, 2013 and 2012, excluding pipeline financing and capital lease obligations, is $2,956.8 million and $2,956.9 million, respectively. We have other financial instruments consisting primarily of cash, cash equivalents, short-term receivables and payables that approximate fair value due to the nature of the instrument and the relatively short maturities.

Note 11. Commitments and Contingencies

Leases

We lease office space, equipment and vehicles that have non-cancelable lease terms. Currently, our outstanding leases have terms up to 12 years. We have subleased part of the office space included in our operating leases for which we received rental payments. The following table summarizes operating lease payments paid and received during the periods indicated:

	Year Ended December 31,		
In thousands	2013	2012	2011
Operating lease payments	$37,211	$33,606	$52,317
Sublease rental receipts	2,237	2,685	2,398

In addition, we expect to receive approximately $14.6 million for 2014 through 2019 under these sublease agreements.

The following table summarizes by year the remaining non-cancelable future payments under these leases as of December 31, 2013:

In thousands	Pipeline and Capital Leases
2014	$ 62,929
2015	62,254
2016	60,819
2017	55,409
2018	50,750
Thereafter	280,272
Total minimum lease payments	572,433
Less: Amount representing interest	(215,748)
Present value of minimum lease payments	$ 356,685

In thousands	Operating Leases
2014	$ 11,695
2015	12,542
2016	12,510
2017	12,774
2018	12,730
Thereafter	67,832
Total minimum lease payments	$130,083

Commitments

We have entered into long-term commitments to purchase CO_2 that are either non-cancelable or cancelable only upon the occurrence of specified future events. The commitments continue for up to 20 years. The price we will pay for CO_2 generally varies depending on the amount of CO_2 delivered and the price of oil. Our annual commitment under these contracts could range from $100 million to $170 million per year, assuming a $90 per Bbl NYMEX oil price.

We are party to long-term contracts that require us to deliver CO_2 to our industrial CO_2 customers at various contracted prices, plus we have a CO_2 delivery obligation to Genesis related to three CO_2 volumetric production payments ("VPPs"). Based upon the maximum amounts deliverable as stated in the industrial contracts and the VPPs, we estimate that we may be obligated to deliver up to 367 Bcf of CO_2 to these customers over the next 15 years. The maximum volume required in any given year is approximately 119 MMcf/d, which we judge to be minor given the size of our Jackson Dome proven CO_2 reserves at December 31, 2013, our current production capabilities and our projected levels of CO_2 usage for our own tertiary flooding program.

In conjunction with the August 2011 Riley Ridge acquisition, we assumed the 20-year helium supply contract under which the original participants in Riley Ridge agreed to supply helium to a third-party purchaser. After the commencement date, the contract provides for the delivery of a minimum contracted quantity of helium, subject to adjustment after start-up of the Riley Ridge gas processing facility, which, if not supplied in accordance with the terms of the contract, may obligate us to compensate the third-party helium purchaser for the amount of the shortfall in an amount not to exceed $8.0 million per year, or $46.0 million over the term of the contract.

Delhi Field Release

In June 2013, a release of well fluids, consisting of a mixture of carbon dioxide, saltwater, natural gas and oil, was discovered and reported within an area of the Denbury-operated Delhi Field located in northern Louisiana. Denbury immediately took remedial action to stop the release and contain and recover well fluids in the affected area. We have determined that the release originated from one or more wells in the affected area of the field that we believed had been previously and properly plugged and abandoned by a prior operator of the field. We completed our remediation efforts during the fourth quarter of 2013; however, we will continue to monitor the area to ensure the remediation efforts were successful.

During the year ended December 31, 2013, we recorded $114.0 million of lease operating expenses related to this release in our Consolidated Statement of Operations, and as of December 31, 2013, we had a corresponding $22.0 million liability classified as "Accounts payable and accrued liabilities" in our Consolidated Balance Sheet. These expenses represent our current estimate of the costs related to this release, including remediation costs, based on actual costs incurred through December 31, 2013 of approximately $92.0 million, plus the Company's estimate of future costs related to the satisfaction of known claims and liabilities. Due to the possibility of new claims being asserted in the future in connection with the release, as well as variability in the estimated cost to continue to monitor the area to ensure the remediation efforts were successful, we cannot reliably estimate at this time the full extent of the costs that may ultimately be incurred by the Company related to this release. Although the Company maintains insurance policies that we believe cover certain of the costs, damages and claims related to the release, and we currently and preliminarily estimate that one-third to two-thirds of our current cost estimate may be recoverable under such insurance policies, we have not reached any agreement with our insurance carriers as to recoverable amounts, and accordingly have not recognized any insurance recoveries in our financial statements as of December 31, 2013. Insurance recoveries will be recognized in our financial statements during the period received or at the time receipt is determined to be virtually certain.

Litigation

We are involved in various lawsuits, claims and regulatory proceedings incidental to our businesses. While we currently believe that the ultimate outcome of these proceedings, individually and in the aggregate, will not have a material adverse effect on our financial position or overall trends in results of operations or cash flows, litigation is subject to inherent uncertainties. If an unfavorable ruling were to occur, there exists the possibility of a material adverse impact on our net income in the period in which the ruling occurs. We provide accruals for litigation and claims if we determine that a loss is probable and the amount can be reasonably estimated.

Other Contingencies

We are subject to audits in the various states in which we operate for sales and use taxes and severance taxes, and from time to time receive assessments for potential taxes that we may owe. In the past, settlement of these matters has not had a material adverse financial impact on us, and currently we have no material assessments for potential taxes.

We are subject to various possible contingencies that arise primarily from interpretation of federal and state laws and regulations affecting the oil and natural gas industry. Such contingencies include differing interpretations as to the prices at which oil and natural gas sales may be made, the prices at which royalty owners may be paid for production from their leases, environmental issues and other matters. Although we believe that we have complied with the various laws and regulations, administrative rulings and interpretations thereof, adjustments could be required as new interpretations and regulations are issued. In addition, production rates, marketing and environmental matters are subject to regulation by various federal and state agencies.

Note 12. Additional Balance Sheet Details

Allowance for Doubtful Accounts

We record an allowance for doubtful accounts for receivables that we determine to be uncollectible based on the specific identification basis. The allowance for doubtful accounts, which is netted against "Trade and other receivables" on the Consolidated Balance Sheets, was $0.3 million at December 31, 2013 and 2012.

Accounts Payable and Accrued Liabilities

	December 31,	
In thousands	2013	2012
Accrued exploration and development costs	$100,564	$109,939
Accrued interest	68,871	60,698
Accounts payable	63,263	86,051
Accrued lease operating expenses	59,762	23,862
Accrued compensation	55,043	48,451
Taxes payable	28,019	27,523
Other	35,021	58,144
Total	$410,543	$414,668

Note 13. Supplemental Cash Flow Information

Supplemental Cash Flow Information

	Year Ended December 31,		
In thousands	2013	2012	2011
Supplemental cash flow information:			
Cash paid for interest, expensed	$ 117,442	$ 137,950	$137,259
Cash paid for interest, capitalized	79,253	77,432	60,540
Cash paid for income taxes	28,895	99,194	45,912
Cash received from income tax refunds	(17,087)	(38,004)	(24,677)
Noncash investing activities:			
Increase in asset retirement obligations	26,946	56,290	24,694
Increase (decrease) in liabilities for capital expenditures	(18,321)	(26,882)	74,697
Increase in restricted cash (1)	—	1,262,559	—
Decrease in restricted cash (2)	1,050,328	212,544	—

(1) During 2012, $212.5 million of proceeds from the sale of certain non-core assets in the Gulf Coast Region and $1.05 billion of the cash proceeds from the Bakken Exchange Transaction were paid by the respective purchaser directly to a qualified intermediary to facilitate a like-kind-exchange transaction for federal income tax purposes. See Note 2, *Acquisitions and Divestitures,* for additional details regarding these transactions.

(2) During 2012 and 2013, proceeds from the sales of our oil and natural gas property dispositions in 2012, which were held by a qualified intermediary, were released in 2012 to fund the Thompson Field acquisition and in 2013 primarily to fund a portion of the CCA acquisition and certain post-closing costs under the Bakken Exchange Transaction. See Note 2, *Acquisitions and Divestitures,* for additional details regarding these transactions.

Note 14. Subsequent Events

Stock Repurchase Program

Between January 1, 2014 and February 20, 2014, the Company repurchased an additional 11.8 million shares of Denbury common stock under the share repurchase program for $191.6 million, or $16.17 per share. See Note 7, *Stockholders' Equity,* for additional information regarding the Company's share repurchase program.

Equity Award Grant

In January 2014, we granted equity incentive awards to our employees under the 2004 Plan. The grants included 1,633,898 shares of restricted stock valued at $16.55 per share (the closing price of Denbury's common stock on January 3, 2014). The awards generally vest 33% per year over a three-year period.

Dividend Declaration

On January 28, 2014, the Board of Directors declared a dividend of $0.0625 per share on our common stock, payable to stockholders of record at the close of business on February 25, 2014.

Supplemental Oil and Natural Gas Disclosures (Unaudited)

Costs Incurred

The following table summarizes costs incurred and capitalized in oil and natural gas property acquisition, exploration and development activities. Property acquisition costs are those costs incurred to purchase, lease or otherwise acquire property, including both undeveloped leasehold and the purchase of reserves in place. Exploration costs include costs of identifying areas that may warrant examination and examining specific areas that are considered to have prospects containing oil and natural gas reserves, including costs of drilling exploratory wells, geological and geophysical costs, and carrying costs on undeveloped properties. Development costs are incurred to obtain access to proved reserve costs, including the cost of drilling development wells, and to provide facilities for extracting, treating, gathering and storing the oil and natural gas, and the cost of improved recovery systems.

We capitalize interest on unevaluated oil and natural gas properties that have ongoing development activities. Included in costs incurred in the table below is capitalized interest of $41.3 million in 2013, $36.5 million in 2012 and $44.9 million in 2011. Costs incurred also include new asset retirement obligations established, as well as changes to asset retirement obligations resulting from revisions in cost estimates or abandonment dates. Asset retirement obligations included in the table below were $17.1 million in 2013, $38.8 million in 2012 and $24.2 million in 2011. See Note 3, *Asset Retirement Obligations,* for additional information.

Costs incurred in oil and natural gas activities were as follows:

	Year Ended December 31,		
In thousands	2013	2012	2011
Property acquisitions:			
Proved	$ 803,837	$ 491,041	$ 86,465
Unevaluated	221,173	115,270	17,858
Exploration	2,103	12,019	31,483
Development	913,093	1,111,314	1,144,243
Total costs incurred (1)	$1,940,206	$1,729,644	$1,280,049

(1) Capitalized general and administrative costs that directly relate to exploration and development activities were $55.4 million, $49.2 million and $35.0 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Oil and Natural Gas Operating Results

Results of operations from oil and natural gas producing activities, excluding corporate overhead and interest costs, were as follows:

	Year Ended December 31,		
In thousands, except per BOE data	2013	2012	2011
Oil, natural gas, and related product sales	$2,466,234	$2,409,867	$2,269,151
Lease operating costs	730,574	532,359	507,397
Marketing expenses, net of third-party purchasers	37,754	41,936	26,047
Taxes other than income	162,791	149,919	138,419
Depletion, depreciation and amortization	426,668	448,424	369,075
CO_2 properties and pipelines depletion and depreciation (1)	52,932	42,064	24,460
Commodity derivatives expense (income)	41,024	(4,834)	(52,497)
Net operating income	1,014,491	1,199,999	1,256,250
Income tax provision	385,507	462,000	477,375
Results of operations from oil and natural gas producing activities	$ 628,984	$ 737,999	$ 778,875
Depletion, depreciation and amortization per BOE	$ 18.71	$ 18.69	$ 16.42

(1) Represents an allocation of the depletion, depreciation and amortization of our CO_2 properties and pipelines associated with our tertiary oil producing activities.

Oil and Natural Gas Reserves

Net proved oil and natural gas reserve estimates for all years presented were prepared by DeGolyer and MacNaughton, independent petroleum engineers located in Dallas, Texas. These oil and natural gas reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interest in our properties. See *Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves* below for a discussion of the effect of the different prices on reserve quantities and values. Operating costs, production and ad valorem taxes, and future development costs were based on current costs.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures. The following reserve data represents estimates only and should not be construed as being exact. Moreover, the present values should not be construed as the current market value of our oil and natural gas reserves or the costs that would be incurred to obtain equivalent reserves. Estimates of reserves as of year-end 2013, 2012 and 2011 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the applicable fiscal 12-month period. All of our reserves are located in the United States.

Estimated Quantities of Proved Reserves

	Year Ended December 31,								
	2013			2012			2011		
	Oil (MBbl)	Gas (MMcf)	Total (MBOE)	Oil (MBbl)	Gas (MMcf)	Total (MBOE)	Oil (MBbl)	Gas (MMcf)	Total (MBOE)
Balance at beginning of year	329,124	481,641	409,398	357,733	625,208	461,934	338,276	357,893	397,925
Revisions of previous estimates	4,704	60	4,714	(7,099)	(16,720)	(9,886)	(4,478)	(14,058)	(6,821)
Revisions due to change in sales prices	665	14,100	3,015	(401)	(37,969)	(6,729)	2,558	485	2,639
Extensions and discoveries	118	—	118	14,910	10,005	16,579	42,936	52,339	51,658
Improved recovery [(1)]	34,015	—	34,015	69,543	—	69,543	264	—	264
Production	(24,194)	(8,666)	(25,639)	(24,462)	(10,654)	(26,238)	(22,169)	(10,783)	(23,966)
Acquisition of minerals in place	42,227	2,819	42,697	24,677	20,598	28,110	346	239,332	40,235
Sales of minerals in place	—	—	—	(105,777)	(108,827)	(123,915)	—	—	—
Balance at end of year	386,659	489,954	468,318	329,124	481,641	409,398	357,733	625,208	461,934
Proved Developed Reserves:									
Balance at beginning of year	236,009	64,191	246,708	239,741	125,970	260,736	219,077	110,516	237,496
Balance at end of year	276,392	72,095	288,408	236,009	64,191	246,708	239,741	125,970	260,736

(1) Improved recovery reflects reserve additions that result from the application of secondary recovery methods such as water flooding, or tertiary recovery methods such as CO_2 flooding. In order to recognize proved tertiary oil reserves, we must either have an oil production response to CO_2 injections or the field must be analogous to an existing tertiary flood. The magnitude of proved reserves that we can book in any given year will depend on our progress with new floods and the timing of the production response.

Acquisitions of minerals in place during 2013 were primarily related to the acquisition of additional interests in certain of our existing operated fields in CCA, as well as operating interests in other CCA fields. Reserves added as a result of improved recovery represent initial proved tertiary oil reserves at Bell Creek Field.

We added 114.2 MMBOE of estimated proved reserves during 2012, including tertiary reserves of 69.5 MMBbls, primarily at Hastings and Oyster Bayou fields; 25.9 MMBOE from the acquisition of interests in the Thompson, Webster and Hartzog Draw fields; and 11.5 MMBOE from our Bakken area assets prior to their sale in the fourth quarter of 2012. These increases were offset by the disposition of 123.9 MMBOE of reserves associated with disposed properties, including our Bakken area assets, and non-core assets in the Gulf Coast region and Paradox Basin in Utah.

Acquisitions of minerals in place during 2011 were primarily related to the acquisition of the remaining interest in Riley Ridge, and extensions and discoveries that year primarily included proved undeveloped reserves added primarily through additional drilling in the Bakken.

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves

The Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves ("Standardized Measure") does not purport to present the fair market value of our oil and natural gas properties. An estimate of such value should consider, among other factors, anticipated future prices of oil and natural gas, the probability of recoveries in excess of existing proved reserves, the value of probable reserves and acreage prospects, and perhaps different discount rates. It should be noted that estimates of reserve quantities, especially from new discoveries, are inherently imprecise and subject to substantial revision.

Under the Standardized Measure, future cash inflows were estimated by applying a first-day-of-the-month 12-month average price to the estimated future production of year-end proved reserves. The product prices used in calculating these reserves have varied widely during the three-year period. These prices have a significant impact on both the quantities and value of the proved reserves, as reductions in oil and natural gas prices can cause wells to reach the end of their economic life much sooner and can make certain proved undeveloped locations uneconomical, both of which reduce the reserves. The following representative oil and natural gas prices were used in the Standardized Measure. These prices were adjusted by field to arrive at the appropriate corporate net price.

	December 31,		
	2013	2012	2011
Oil (NYMEX price per Bbl)	$96.94	$94.71	$96.19
Natural Gas (Henry Hub price per Mcf)	3.67	2.85	4.16

Future cash inflows were reduced by estimated future production, development and abandonment costs based on current cost, with no escalation to determine pre-tax cash inflows. Our future net inflows do not include a reduction for cash previously expended on our capitalized CO_2 assets that will be consumed in the production of proved tertiary reserves. Future income taxes were computed by applying the statutory tax rate to the excess of net cash inflows over our tax basis in the associated proved oil and natural gas properties. Tax credits and net operating loss carryforwards were also considered in the future income tax calculation. Future net cash inflows after income taxes were discounted using a 10% annual discount rate to arrive at the Standardized Measure.

	December 31,		
In thousands	2013	2012	2011
Future cash inflows	$ 40,065,019	$ 34,779,549	$ 38,165,122
Future production costs	(16,053,734)	(13,114,740)	(12,570,015)
Future development costs	(2,552,194)	(2,034,174)	(3,026,898)
Future income taxes	(6,937,773)	(6,672,857)	(7,379,972)
Future net cash flows	14,521,318	12,957,778	15,188,237
10% annual discount for estimated timing of cash flows	(7,392,574)	(6,543,398)	(8,180,632)
Standardized measure of discounted future net cash flows	$ 7,128,744	$ 6,414,380	$ 7,007,605

The following table sets forth an analysis of changes in the Standardized Measure of Discounted Future Net Cash Flows from proved oil and natural gas reserves:

	Year Ended December 31,		
In thousands	2013	2012	2011
Beginning of year	$ 6,414,380	$ 7,007,605	$ 4,917,927
Sales of oil and natural gas produced, net of production costs (1)	(1,649,113)	(1,673,253)	(1,597,288)
Net changes in prices and production costs	(170,571)	(597,512)	4,231,076
Extensions and discoveries, less applicable future development and production costs	4,902	291,558	762,370
Improved recovery (2)	739,019	1,901,109	15,708
Previously estimated development costs incurred	393,537	376,199	354,228
Change in future development costs	(301,162)	(454,140)	(591,570)
Revisions due to timing and other	(446,586)	(330,849)	(666,703)
Accretion of discount	1,072,113	875,383	729,234
Acquisition of minerals in place	1,082,050	767,267	29,737
Sales of minerals in place	—	(1,805,309)	—
Net change in income taxes	(9,825)	56,322	(1,177,114)
End of year	$ 7,128,744	$ 6,414,380	$ 7,007,605

(1) Production costs exclude $114 million of lease operating expenses recorded during the year ended December 31, 2013 related to the Delhi Field release.

(2) Improved recovery additions result from the application of secondary recovery methods such as water flooding or tertiary recovery methods such as CO_2 flooding.

Supplemental CO_2 And Helium Disclosures (Unaudited)

Based on engineering reports prepared by DeGolyer and MacNaughton, proved CO_2 reserves, and helium reserves associated with our helium production rights, were estimated as follows (in MMcf):

In thousands	Year Ended December 31, 2013	2012	2011
CO_2 reserves			
Gulf Coast region (1)	6,070,619	6,073,175	6,685,412
Rocky Mountain region (2)	3,272,428	3,495,534	2,195,534
Helium reserves associated with Denbury's production rights			
Rocky Mountain region (3)	13,251	12,712	12,004

(1) Proved CO_2 reserves in the Gulf Coast region consist of reserves from our reservoirs at Jackson Dome and are presented on a gross working interest (8/8ths) basis, of which our net revenue interest was approximately 4.8 Tcf, 4.8 Tcf and 5.3 Tcf at December 31, 2013, 2012 and 2011, respectively, and include reserves dedicated to volumetric production payments of 28.9 Bcf, 57.1 Bcf and 84.7 Bcf at December 31, 2013, 2012 and 2011, respectively.

(2) Proved CO_2 reserves in the Rocky Mountain region consist of our reserves at Riley Ridge (presented on a gross working interest (8/8ths) basis) and our overriding royalty interest in LaBarge Field, of which our net revenue interest was approximately 2.9 Tcf, 2.9 Tcf and 1.6 Tcf at December 31, 2013, 2012 and 2011, respectively.

(3) Reserves associated with helium production rights include helium reserves located in acreage in the Rocky Mountain region for which we have the right to extract the helium on behalf of the U.S. government, who owns the helium. Our extraction agreement with the U.S. government gives us the ability to produce the helium on behalf of the U.S. government in exchange for a fee, which amount fluctuates based upon the realized sales proceeds we receive. The estimate of helium reserves is reduced to reflect the estimated fee we will remit to the U.S. government. Our extraction agreement with the U.S. government has a minimum term extending 20 years from first production and continuing thereafter until either party terminates the contract. Reserve volumes presented herein assume that the term of this helium extraction agreement continues beyond 20 years, given the benefit to both parties to the agreement.

Unaudited Quarterly Information

In thousands, except per share amounts	March 31	June 30	September 30	December 31
2013				
Revenues and other income	$ 583,086	$ 650,084	$ 684,835	$ 599,122
Commodity derivatives expense (income)	11,929	(45,501)	80,446	(5,850)
Other expenses	429,222	484,279	445,024	475,198
Net income	87,571	129,980	102,054	89,992
Net income per share:				
Basic	0.24	0.35	0.28	0.25
Diluted	0.23	0.35	0.28	0.25
Cash flow provided by operating activities	269,176	437,568	305,465	348,986
Cash flow used for investing activities	(320,646)	(344,927)	(286,130)	(323,606)
Cash flow provided by (used for) financing activities	15,228	(79,045)	(68,652)	(39,741)
2012				
Revenues and other income	$ 645,116	$ 601,781	$ 600,371	$ 609,204
Commodity derivatives expense (income)	45,275	(139,109)	61,631	27,369
Other expenses	420,529	398,089	399,361	386,470
Net income	113,467	211,865	85,367	114,661
Net income per share:				
Basic	0.29	0.55	0.22	0.30
Diluted	0.29	0.54	0.22	0.30
Cash flow provided by operating activities	291,654	440,966	293,506	384,765
Cash flow used for investing activities	(288,883)	(560,341)	(388,748)	(138,869)
Cash flow provided by (used for) financing activities	55,902	70,122	91,163	(171,419)

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) was performed under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2013, to ensure that information that is required to be disclosed in the reports the Company files and submits under the Securities Exchange Act of 1934 is recorded; that it is processed, summarized and reported within the time periods specified in the SEC's rules and forms; and that information that is required to be disclosed under the Exchange Act is accumulated and communicated to management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Evaluation of Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we have determined that, during the fourth quarter of fiscal 2013, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we assessed the effectiveness of our internal control over financial reporting as of the end of the period covered by this report based on the framework in "Internal Control – Integrated Framework" (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that assessment, our Chief Executive Officer and our Chief Financial Officer concluded that our internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of our financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

The effectiveness of our internal control over financial reporting as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in the report that appears herein.

Important Considerations

The effectiveness of our disclosure controls and procedures and our internal control over financial reporting is subject to various inherent limitations, including cost limitations, judgments used in decision making, assumptions about the likelihood of future events, the soundness of our systems, the possibility of human error, and the risk of fraud. Moreover, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions and the risk that the degree of compliance with policies or procedures may deteriorate over time. Because of these limitations, there can be no assurance that any system of disclosure controls and procedures or internal control over financial reporting will be successful in preventing all errors or fraud or in making all material information known in a timely manner to the appropriate levels of management.

Item 9B. Other Information

None.

Item 10. Directors, Executive Officers and Corporate Governance

Except as disclosed below, information as to Item 10 will be set forth in the Proxy Statement ("Proxy Statement") for the Annual Meeting of Shareholders to be held May 20, 2014 ("Annual Meeting") and is incorporated herein by reference.

Code of Ethics

We have adopted a Code of Ethics for Senior Financial Officers and the Principal Executive Officer. This Code of Ethics, including any amendments or waivers, is posted on our website at www.denbury.com.

Item 11. Executive Compensation

Information as to Item 11 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

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

Information as to Item 12 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

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

Information as to Item 13 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

Information as to Item 14 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 15. Exhibits and Financial Statement Schedules

Financial Statements and Schedules. Financial statements and schedules filed as a part of this report are presented on page 67. All financial statement schedules have been omitted because they are not applicable, or the required information is presented in the financial statements or the notes to consolidated financial statements.

Exhibits. The following exhibits are included as part of this report.

Exhibit No.	Exhibit
2(a)	Exchange Agreement, dated as of September 19, 2012, by and among Denbury Onshore, LLC, XTO Energy Inc., and Exxon Mobil Corporation (incorporated by reference to Exhibit 2.1 of Form 8-K filed by the Company on September 25, 2012, File No. 001-12935).
2(b)	Closing Agreement and Amendment, dated as of November 30, 2012, by and among Denbury Onshore, LLC, XTO Energy Inc., and Exxon Mobil Corporation (incorporated by reference to Exhibit 2.2 of Form 8-K filed by the Company on December 6, 2012, File No. 001-12935).
2(c)	Second Closing Agreement and Amendment, dated as of December 21, 2012, by and among Denbury Onshore, LLC, XTO Energy Inc., and Exxon Mobil Corporation (incorporated by reference to Exhibit 2.1 of Form 8-K filed by the Company on December 26, 2012, File No. 001-12935).
2(d)	Purchase and Sale Agreement, dated as of January 14, 2013, by and between Burlington Resources Oil & Gas Company LP and Denbury Onshore, LLC (incorporated by reference to Exhibit 2.1 of Form 8-K filed by the Company on January 15, 2013, File No. 001-12935).
3(a)	Second Restated Certificate of Incorporation of Denbury Resources Inc. filed with the Delaware Secretary of State on August 21, 2012 (incorporated by reference to Exhibit 3(a) of Form 10-Q filed by the Company on November 8, 2012, File No. 001-12935).
3(b)	Amended and Restated Bylaws of Denbury Resources Inc. as of May 15, 2012 (incorporated by reference to Exhibit 3.2 of Form 8-K filed by the Company on May 21, 2012, File No. 001-12935).
4(a)	Indenture for 9.75% Senior Subordinated Notes due 2016, dated as of February 13, 2009, by and among Denbury Resources Inc., certain of its subsidiaries, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.1 of Form 8-K filed by the Company on February 17, 2009, File No. 001-12935).
4(b)	First Supplemental Indenture for 9.75% Senior Subordinated Notes due 2016, dated as of June 30, 2009, by and among Denbury Resources Inc., certain of its subsidiaries, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4(h) of Form 10-K filed by the Company on March 1, 2010, File No. 001-12935).
4(c)**	9.75% Senior Subordinated Note due 2016, issued on June 30, 2009, to Gareth Roberts (incorporated by reference to Exhibit 10.2 of Form 8-K filed by the Company on July 7, 2009, File No. 001-12935).
4(d)	Second Supplemental Indenture for 9.75% Senior Subordinated Notes due 2016, dated as of March 9, 2010, by and among Denbury Resources Inc., certain of its subsidiaries, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.6 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(e)	Third Supplemental Indenture for 9.75% Senior Subordinated Notes due 2016, dated as of February 3, 2011, by and among Denbury Resources Inc., certain of its subsidiaries, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4(p) of Form 10-K filed by the Company on March 1, 2011, File No. 001-12935).
4(f)	Indenture for 8¼% Senior Subordinated Notes due 2020, dated as of February 10, 2010, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 of Form 8-K filed by the Company on February 12, 2010, File No. 001-12935).

Exhibit No.	Exhibit
4(g)	First Supplemental Indenture for 8¼% Senior Subordinated Notes due 2020, dated as of March 9, 2010, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.7 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(h)	Second Supplemental Indenture for 8¼% Senior Subordinated Notes due 2020, dated as of February 3, 2011, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4(s) of Form 10-K filed by the Company on March 1, 2011, File No. 001-12935).
4(i)	Indenture for 6.25% Senior Subordinated Notes Due 2014, dated as of April 2, 2004, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1.1 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(j)	First Supplemental Indenture for 6.25% Senior Subordinated Notes Due 2014, dated as of January 2, 2008, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1.2 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(k)	Second Supplemental Indenture for 6.25% Senior Subordinated Notes Due 2014, dated as of January 27, 2010, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1.3 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(l)	Third Supplemental Indenture for 6.25% Senior Subordinated Notes Due 2014, dated as of March 10, 2010, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1.4 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(m)	Fourth Supplemental Indenture for 6.25% Senior Subordinated Notes Due 2014, dated as of February 3, 2011, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4(x) of Form 10-K filed by the Company on March 1, 2011, File No. 001-12935).
4(n)	Indenture for 6.0% Senior Subordinated Notes due 2015, dated as of July 13, 2005, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2.1 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(o)	First Supplemental Indenture for 6.0% Senior Subordinated Notes due 2015, dated as of January 2, 2008, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2.2 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(p)	Second Supplemental Indenture for 6.0% Senior Subordinated Notes due 2015, dated as of January 27, 2010, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2.3 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(q)	Third Supplemental Indenture for 6.0% Senior Subordinated Notes due 2015, dated as of March 10, 2010, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2.4 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(r)	Fourth Supplemental Indenture for 6.0% Senior Subordinated Notes due 2015, dated as of February 3, 2011, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4(cc) of Form 10-K filed by the Company on March 1, 2011, File No. 001-12935).

Exhibit No.	Exhibit
4(s)	Indenture for Subordinated Debt Securities, dated as of November 16, 2005, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3.1 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(t)	First Supplemental Indenture for 7.25% Senior Subordinated Notes due 2017, dated as of November 23, 2005, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3.2 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(u)	Second Supplemental Indenture for 7.25% Senior Subordinated Notes due 2017, dated as of January 2, 2008, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3.3 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(v)	Third Supplemental Indenture for 9.5% Senior Subordinated Notes due 2016, dated as of April 27, 2009, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3.4 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(w)	Fourth Supplemental Indenture for Senior Subordinated Notes, dated as of January 27, 2010, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3.5 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(x)	Fifth Supplemental Indenture for Senior Subordinated Notes, dated as of March 10, 2010, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3.6 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(y)	Sixth Supplemental Indenture for Senior Subordinated Notes, dated as of February 3, 2011, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4(jj) of Form 10-K filed by the Company on March 1, 2011, File No. 001-12935).
4(z)	Seventh Supplemental Indenture for Senior Subordinated Notes, dated as of February 5, 2013, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 of Form 8-K filed by the Company on February 5, 2013, File No. 001-12935).
4(aa)	Indenture for 6 3/8% Senior Subordinated Notes due 2021, dated as of February 17, 2011, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee, (incorporated by reference to Exhibit 4.1 of Form 8-K filed by the Company on February 22, 2011, File No. 001-12935).
4(bb)	Indenture for 4 5/8% Senior Subordinated Notes due 2023, dated as of February 5, 2013, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 of Form 8-K filed by the Company on February 5, 2013, File No. 001-12935).
10(a)	Credit Agreement, dated as of March 9, 2010, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
10(b)	First Amendment to Credit Agreement, dated as of May 13, 2010, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on May 19, 2010, File No. 001-12935).

Exhibit No.	Exhibit
10(c)	Second Amendment to Credit Agreement, dated as of September 30, 2010, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10.1 of Form 10-Q filed by the Company on November 9, 2010, File No. 001-12935).
10(d)	Third Amendment to Credit Agreement, dated as of December 17, 2010, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10(d) of Form 10-K filed by the Company on March 1, 2011, File No. 001-12935).
10(e)	Fourth Amendment to Credit Agreement, dated as of February 1, 2011, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10(e) of Form 10-K filed by the Company on March 1, 2011, File No. 001-12935).
10(f)	Fifth Amendment to Credit Agreement, dated as of May 19, 2011, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 99.1 of Form 8-K filed by the Company on May 20, 2011, File No. 001-12935).
10(g)	Sixth Amendment to Credit Agreement, dated as of September 1, 2011, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on September 8, 2011, File No. 001-12935).
10(h)	Seventh Amendment to Credit Agreement, dated as of April 11, 2012, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 4(a) of Form 10-Q filed by the Company on May 10, 2012, File No. 001-12935).
10(i)	Eighth Amendment to Credit Agreement, dated as of July 26, 2012, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 4(a) of Form 10-Q filed by the Company on August 8, 2012, File No. 001-12935).
10(j)	Ninth Amendment to Credit Agreement, dated as of November 2, 2012, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10(a) of Form 10-Q filed by the Company on November 8, 2012, File No. 001-12935).
10(k)	Tenth Amendment to Credit Agreement, dated as of January 18, 2013, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10(k) of Form 10-K filed by the Company on February 28, 2013, File No. 001-12935).
10(l)*	Eleventh Amendment to Credit Agreement, dated as of November 8, 2013, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto.
10(m)	Pipeline Financing Lease Agreement, dated as of May 30, 2008, by and between Genesis NEJD Pipeline, LLC, as Lessor, and Denbury Onshore, LLC, as Lessee (incorporated by reference to Exhibit 99.1 of Form 8-K filed by the Company on June 5, 2008, File No. 001-12935).
10(n)	Transportation Services Agreement, dated as of May 30, 2008, by and between Genesis Free State Pipeline, LLC and Denbury Onshore, LLC (incorporated by reference to Exhibit 99.2 of Form 8-K filed by the Company on June 5, 2008, File No. 001-12935).
10(o)**	Denbury Resources Inc. Amended and Restated Stock Option Plan, effective as of December 5, 2007 (incorporated by reference to Exhibit 99.2 of Form 8-K filed by the Company on December 11, 2007, File No. 001-12935).

Exhibit No.	Exhibit
10(p)**	Denbury Resources Inc. Amended and Restated Employee Stock Purchase Plan, effective as of May 22, 2013 (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on May 28, 2013, File No. 001-12935).
10(q)**	Form of Indemnification Agreement, dated as of July 28, 1999, by and between Denbury Resources Inc. and its officers and directors (incorporated by reference to Exhibit 10 of Form 10-Q filed by the Company on August 11, 1999, File No. 001-12935).
10(r)* **	Denbury Resources Inc. Director Deferred Compensation Plan, as amended and restated effective as of December 12, 2013.
10(s)**	Denbury Resources Inc. Severance Protection Plan, as amended and restated effective as of December 13, 2012 (incorporated by reference to Exhibit 10(v) of Form 10-K filed by the Company on February 28, 2013, File No. 001-12935).
10(t)* **	Denbury Resources Inc. 2004 Omnibus Stock and Incentive Plan, as amended and restated as of December 12, 2013.
10(u)**	2004 Form of Restricted Stock Award that vests on retirement for grants to officers pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(l) of Form 10-K filed by the Company on March 15, 2005, File No. 001-12935).
10(v)**	2009 Form of Stock Appreciation Rights Agreement to certain officers that cliff vests on March 31, 2012 pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(f) of Form 10-Q filed by the Company on May 11, 2009, File No. 001-12935).
10(w)**	2009 Form of Stock Appreciation Rights Agreement without change of control vesting pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(g) of Form 10-Q filed by the Company on May 11, 2009, File No. 001-12935).
10(x)**	2011 Form of Performance Stock Award pursuant to the 2004 Omnibus Stock and Incentive Plan (incorporated by reference to Exhibit 10(a) to Form 10-Q filed by the Company on May 10, 2011, File No. 001-12935).
10(y)**	2011 Form of Performance Cash Award pursuant to the 2004 Omnibus Stock and Incentive Plan (incorporated by reference to Exhibit 10(b) to Form 10-Q filed by the Company on May 10, 2011, File No. 001-12935).
10(z)* **	Officer Resignation Agreement, effective as of December 31, 2013, by and between Denbury Resources Inc. and Robert L. Cornelius.
10(aa)**	2012 Form of Performance Stock Award pursuant to the 2004 Omnibus Stock and Incentive Plan (incorporated by reference to Exhibit 10(a) of Form 10-Q filed by the Company on May 10, 2012, File No. 001-12935).
10(bb)**	2012 Form of Performance Cash Award pursuant to the 2004 Omnibus Stock and Incentive Plan (incorporated by reference to Exhibit 10(b) of Form 10-Q filed by the Company on May 10, 2012, File No. 001-12935).
10(cc)**	2012 Form of TSR Performance Award pursuant to the 2004 Omnibus Stock and Incentive Plan (incorporated by reference to Exhibit 10(c) of Form 10-Q filed by the Company on May 10, 2012, File No. 001-12935).
10(dd)**	2013 Form of Performance Share Award pursuant to the 2004 Omnibus Stock and Incentive Plan (incorporated by reference to Exhibit 10(a) of Form 10-Q filed by the Company on May 10, 2013, File No. 001-12935).
10(ee)**	2013 Form of Performance Cash Award pursuant to the 2004 Omnibus Stock and Incentive Plan (incorporated by reference to Exhibit 10(b) of Form 10-Q filed by the Company on May 10, 2013, File No. 001-12935).

Exhibit No.	Exhibit
10(ff)**	2013 Form of TSR Performance Award pursuant to the 2004 Omnibus Stock and Incentive Plan (incorporated by reference to Exhibit 10(c) of Form 10-Q filed by the Company on May 10, 2013, File No. 001-12935).
10(gg)**	2013 Form of Stock Appreciation Rights Agreement pursuant to the 2004 Omnibus Stock and Incentive Plan (incorporated by reference to Exhibit 10(e) of Form 10-Q filed by the Company on May 10, 2013, File No. 001-12935).
10(hh)**	2013 Form of Restricted Share Award to officers pursuant to the 2004 Omnibus Stock and Incentive Plan (incorporated by reference to Exhibit 10(d) of Form 10-Q filed by the Company on May 10, 2013, File No. 001-12935).
10(ii)**	2013 Form of Restricted Share Award to non-employee directors pursuant to the 2004 Omnibus Stock and Incentive Plan (incorporated by reference to Exhibit 10(c) of Form 10-Q filed by the Company on August 6, 2013, File No. 001-12935).
10(jj)**	2013 Form of Deferred Stock Unit Award pursuant to the Director Deferred Compensation Plan (with respect to deferred long-term incentive awards) (incorporated by reference to Exhibit 10(d) of Form 10-Q filed by the Company on August 6, 2013, File No. 001-12935).
10(kk)**	2013 Form of Deferred Stock Unit Agreement pursuant to the Director Deferred Compensation Plan (with respect to deferred director fees) (incorporated by reference to Exhibit 10(e) of Form 10-Q filed by the Company on August 6, 2013, File No. 001-12935).
21*	List of subsidiaries of Denbury Resources Inc.
23(a)*	Consent of PricewaterhouseCoopers LLP.
23(b)*	Consent of DeGolyer and MacNaughton.
31(a)*	Certification of Chief Executive Officer Pursuant to Section 302 of Sarbanes-Oxley Act of 2002.
31(b)*	Certification of Chief Financial Officer Pursuant to Section 302 of Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99*	The summary of DeGolyer and MacNaughton's Report as of December 31, 2013, on oil and gas reserves (SEC Case) dated January 31, 2014.

* Included herewith.

** Compensation arrangements.

SIGNATURES

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

DENBURY RESOURCES INC.

/s/ Mark C. Allen February 28, 2014
Mark C. Allen
Sr. Vice President and Chief Financial Officer

/s/ Alan Rhoades February 28, 2014
Alan Rhoades
Vice President and Chief Accounting Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of Denbury Resources Inc. and in the capacities and on the dates indicated.

/s/ Phil Rykhoek February 28, 2014
Phil Rykhoek
Director, President and Chief Executive Officer
(Principal Executive Officer)

/s/ John P. Dielwart February 28, 2014
John P. Dielwart
Director

/s/ Mark C. Allen February 28, 2014
Mark C. Allen
Sr. Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ Ronald G. Greene February 28, 2014
Ronald G. Greene
Director

/s/ Alan Rhoades February 28, 2014
Alan Rhoades
Vice President and Chief Accounting Officer
(Principal Accounting Officer)

/s/ Gregory L. McMichael February 28, 2014
Gregory L. McMichael
Director

/s/ Wieland F. Wettstein February 28, 2014
Wieland F. Wettstein
Director

/s/ Kevin O. Meyers February 28, 2014
Kevin O. Meyers
Director

/s/ Michael L. Beatty February 28, 2014
Michael L. Beatty
Director

/s/ Randy Stein February 28, 2014
Randy Stein
Director

/s/ Michael B. Decker February 28, 2014
Michael B. Decker
Director

/s/ Laura A. Sugg February 28, 2014
Laura A. Sugg
Director

Exhibit 21

LIST OF SUBSIDIARIES

Name Of Subsidiary	Jurisdiction Of Organization
Denbury Operating Company	Delaware
Denbury Onshore, LLC	Delaware
Denbury Pipeline Holdings, LLC	Delaware
Denbury Holdings, Inc.	Delaware
Denbury Green Pipeline – Texas, LLC	Delaware
Greencore Pipeline Company, LLC	Delaware
Denbury Gulf Coast Pipelines, LLC	Delaware

Exhibit 23(a)

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (Nos. 333-01006, 333-27995, 333-55999, 333-70485, 333-39172, 333-39218, 333-39224, 333-63198, 333-90398, 333-106253, 333-116249, 333-143848, 333-160178, 333-167480, 333-175273 and 333-189438) and Form S-3 (No. 333-186112) of Denbury Resources Inc. of our report dated February 28, 2014 relating to the consolidated financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Dallas, Texas
February 28, 2014

Exhibit 23(b)

DEGOLYER AND MACNAUGHTON
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

February 26, 2014

DENBURY RESOURCES INC.
5320 Legacy Drive
Plano, Texas 75024

Ladies and Gentlemen:

We hereby consent to the use of the name DeGolyer and MacNaughton, to references to DeGolyer and MacNaughton, to the inclusion of our Letter Report dated January 31, 2014, regarding the proved reserves of Denbury Resources, and to the inclusion of information taken from our "Appraisal Report as of December 31, 2013 on Certain Properties owned by Denbury Resources Inc. SEC Case", "Appraisal Report as of December 31, 2012 on Certain Properties owned by Denbury Resources Inc. SEC Case", and "Appraisal Report as of December 31, 2011 on Certain Properties owned by Denbury Resources Inc. SEC Case", in the Annual Report on Form 10-K of Denbury Resources Inc. for the year ended December 31, 2013.

Very truly yours,

/s/ DeGolyer and MacNaughton

DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716

Exhibit 31(a)

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Phil Rykhoek, certify that:

1. I have reviewed this report on Form 10-K of Denbury Resources Inc. (the registrant);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Phil Rykhoek February 28, 2014

Phil Rykhoek
President and Chief Executive Officer

Exhibit 31(b)

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark C. Allen, certify that:

1. I have reviewed this report on Form 10-K of Denbury Resources Inc. (the registrant);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Mark C. Allen February 28, 2014

Mark C. Allen
Senior Vice President, Chief Financial Officer, Treasurer,
and Assistant Secretary

Exhibit 32

CERTIFICATION OF CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Annual Report on Form 10-K for the year ended December 31, 2013 (the Report) of Denbury Resources Inc. (Denbury) as filed with the Securities and Exchange Commission, each of the undersigned, in his capacity as an officer of Denbury, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
2. information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Denbury.

/s/ Phil Rykhoek February 28, 2014

Phil Rykhoek
President and Chief Executive Officer

/s/ Mark C. Allen February 28, 2014

Mark C. Allen
Senior Vice President, Chief Financial Officer, Treasurer, and Assistant Secretary

Corporate Information

Stock Exchange Listing

New York Stock Exchange ("NYSE")
Ticker Symbol: DNR

Corporate Headquarters

Denbury Resources Inc.
5320 Legacy Drive
Plano, Texas 75024
972.673.2000
www.denbury.com

Stock Transfer Agent & Registrar

For questions concerning dividends, stock certificates, transfer procedures or address changes, please contact:

American Stock Transfer and Trust Company
6201 15th Avenue
Brooklyn, NY 11219
800.937.5449
Email: info@amstock.com
www.amstock.com

Investor Inquiries

Phil Rykhoek
President & Chief Executive Officer
972.673.2000

Mark Allen
Senior Vice President &
Chief Financial Officer
972.673.2000

Jack Collins
Executive Director, Finance and
Investor Relations
972.673.2028
Email: jack.collins@denbury.com

Annual Certifications

During 2013, our Chief Financial Officer certified to the NYSE that he is not aware of any violation by the Company of the NYSE's corporate governance listing standards.

Financial Information Requests

For additional information and to receive additional copies of the Annual Report on Form 10-K as filed with the Securities and Exchange Commission ("SEC") or to obtain other Denbury public documents, please contact:

Denbury Resources Inc.
Investor Relations
5320 Legacy Drive
Plano, Texas 75024
972.673.2000
Email: ir@denbury.com

Our Form 10-K filed with the SEC is included herein, excluding all exhibits other than our Section 302, 404 and 906 certifications by the CEO and CFO. We will send shareholders our Form 10-K exhibits and any of our corporate governance documents, without charge, upon request. These documents are also available on our website at www.denbury.com.

Annual Meeting

The Annual Meeting of Stockholders will be held on Tuesday, May 20, 2014, at 3:00 P.M. CDT at the Dallas/Plano Marriott at Legacy Town Center, located at 7121 Bishop Road, Plano, Texas 75024.

Legal Counsel

Baker & Hostetler LLP

Bankers

J.P. Morgan (Agent)

Auditors

PricewaterhouseCoopers LLP

Reserve Engineers

DeGolyer and MacNaughton

DNR LISTED NYSE

Designed by Eisenberg And Associates

Denbury Resources Inc.

5320 Legacy Drive | Plano, Texas 75024 | 972.673.2000 | www.denbury.com