Denbury

2016
ANNUAL REPORT



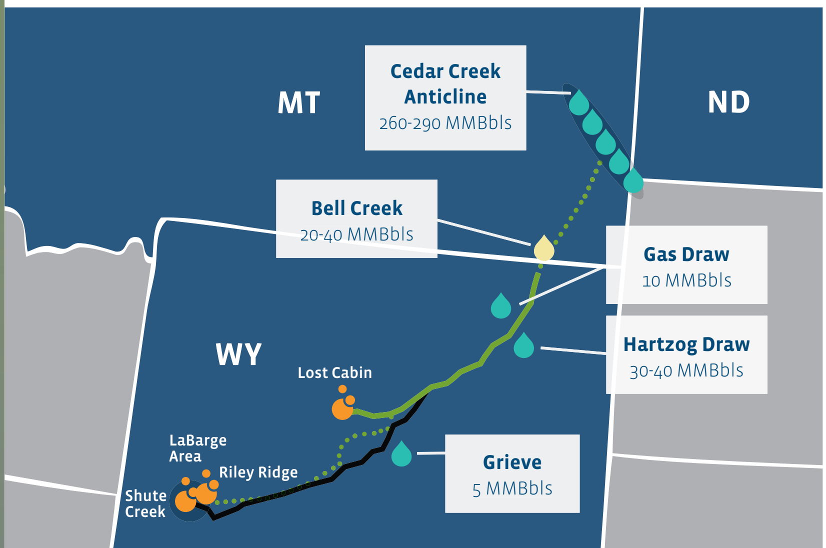

FORWARD-LOOKING STATEMENTS

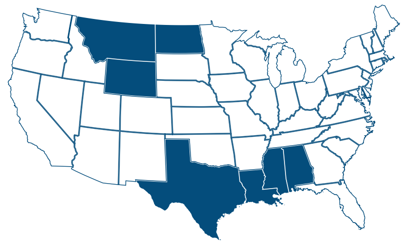
The data and/or statements contained in this annual report that are not historical facts are forward-looking statements, as that term is defined in Section 21E of the Securities Exchange Act of 1934, as amended, that involve a number of risks and uncertainties. Such forward-looking statements may be or may concern, among other things, financial forecasts, future hydrocarbon prices and timing and degree of any price recovery versus the length or severity of the current commodity price downturn, current or future liquidity sources or their adequacy to support our anticipated future activities, our ability to further reduce our debt levels, possible future write-downs of oil and natural gas reserves, together with assumptions based on current and projected oil and gas prices and oilfield costs, current or future expectations or estimations of our cash flows, availability of capital, borrowing capacity, future interest rates, availability of advantageous commodity derivative contracts or the predicted cash flow benefits therefrom, forecasted capital expenditures, drilling activity or methods, including the timing and location thereof, estimated timing of commencement of carbon dioxide (CO_2) flooding of particular fields or areas, dates of completion of to-be-constructed industrial plants and the initial date of capture of 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, anticipated future cost savings, capital budgets, interpretation or prediction of formation details, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO_2 reserves and supply and their availability, potential reserves, barrels or percentages of recoverable original oil in place, potential increases in regional or worldwide tariffs or other trade restrictions, the likelihood, timing and impact of increased interest rates, the impact of regulatory rulings or changes, anticipated outcomes of pending litigation, prospective legislation affecting the oil and gas industry, environmental regulations, mark-to-market values, competition, long-term forecasts of production, rates of return, estimated costs, changes in costs, future capital expenditures and overall economics, worldwide economic conditions and other variables surrounding our estimated original oil in place, operations and future plans. Such forward-looking statements generally are accompanied by words such as “plan,” “estimate,” “expect,” “predict,” “forecast,” “to our knowledge,” “anticipate,” “projected,” “preliminary,” “should,” “assume,” “believe,” “may” or other words that convey, or are intended to 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 and adversely 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 in worldwide oil prices or in U.S. oil prices and consequently in the prices received or demand for our oil and natural gas; decisions as to production levels and/or pricing by OPEC in future periods; levels of future capital expenditures; 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 and remediation costs; disruption of operations and damages from well incidents, hurricanes, tropical storms, or forest fires; acquisition risks; requirements for capital or its availability; conditions in the worldwide financial, trade and credit markets; general economic conditions; competition; government regulations, including tax and environmental; 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.

Current SEC rules regarding oil and gas reserves 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, 2016 were estimated by DeGolyer & MacNaughton, an independent petroleum engineering firm. In this annual report, we may 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 may 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 resources 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.

OPERATING AREAS

ROCKY MOUNTAIN REGION: POTENTIAL TERTIARY RESERVES[1]





Proved Reserves & Tertiary Potential (MMBOEs)

Tertiary Reserves[2]	
Proved	149
Potential	649
Non-Tertiary Reserves[2][3]	
Proved	105

GULF COAST REGION: POTENTIAL TERTIARY RESERVES[1]

- Headquarters
- Existing CO_2 Pipelines Owned or Operated by Denbury
- 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
- Industrial CO_2 Sources: Producing or Pending Start Up

(1) Field reserves shown are estimated proved plus potential tertiary reserves.

(2) Proved tertiary and non-tertiary oil and natural gas reserves based upon year-end 12/31/16 SEC pricing. Potential includes probable and possible tertiary reserves estimated by the Company as of 12/31/16, using the mid-point of ranges, based upon a variety of recovery factors and long-term oil price assumptions, which also may include estimates of resources that do not rise to the standards of possible reserves. See "Forward-looking Statements" for additional information.

(3) Excludes additional potential related to non-tertiary exploitation opportunities.

DEAR FELLOW SHAREHOLDERS

The last two years have presented a challenging environment as the industry has endured the most significant and prolonged oil price downturn in history. After hitting a 14-year low of $26 per barrel in February, oil prices generally increased throughout 2016, ending the year at around $50 per barrel, supported in large part by the agreement of the Organization of Petroleum Exporting Countries (“OPEC”) and certain non-OPEC countries to limit production. While we now see prospects for more long-term stability in the oil markets with a near balance of supply and demand, there is still a great deal of uncertainty around the near-term direction of oil prices, mainly driven by persistent high oil inventory levels, the recent sharp increase in shale drilling activity, and concerns about the duration of the commitment of OPEC and others to curtail production.

At Denbury, we responded quickly to the decline in oil prices, reducing our 2015 capital expenditures by over 60% from 2014, then reducing our 2016 capital by almost 50% from 2015. Our focus throughout this down cycle has been on the execution of four core goals: reducing costs, optimizing our business, reducing debt, and preserving cash and liquidity. We believe our results on the execution of these core goals has been significant and impactful.

We completed a robust review of each of our fields, identifying multiple opportunities to enhance value, including through the expansion and optimization of currently producing fields, as well as via other exploitation opportunities. During 2016, we reduced our full-year cash operating costs (including general and administrative costs and interest) by over $2 per barrel of oil equivalent from 2015, and by over $9 per barrel of oil equivalent since 2014. On an absolute-dollar basis, we lowered our combined lease operating and general and administrative expenses by nearly $135 million, or 20%, from 2015, and by $281 million, or 35%, compared to 2014. Although a portion of these savings is attributable to lower supplier costs, we do not expect to experience the same level of inflation forecasted by many of our industry peers as prices improve. Accordingly, we anticipate that many of our cost reductions will be sustainable, allowing us to develop our high-quality assets and expand our competitive operating margins.

Our business optimization efforts have not only generated significant cost savings to date, but they will provide additional benefits in the revamping of future projects. One of our more significant achievements is our improvement in CO_2 utilization. This was accomplished through a complete utilization re-evaluation, ensuring that injected volumes of CO_2 were generating the intended benefits and identifying areas for improvement. As a result of this work, we lowered our total company CO_2 usage in 2016 by 44% from early 2015, or, stated another way, we reduced our injection of nearly one billion cubic feet of CO_2 per day in early 2015, to an average of just over 500 million cubic feet per day in 2016. In addition to lowering our operating costs, this reduction in usage brings significant additional benefits to our long-range plans. In the past, CO_2 supply and distribution had been a potential limiting factor in our long-term plans for developing our floods. With this improved CO_2 efficiency, our CO_2 supply at Jackson Dome, where we are currently producing at less than 60% of the operational capacity, can service additional future CO_2 floods. We also expect to begin taking CO_2 deliveries from Mississippi Power’s Kemper County power plant in the first half of 2017. Combined, this additional CO_2 supply capacity presents many new opportunities to expand our business beyond what we previously thought practicable.

In addition to CO_2 utilization efficiencies, we created further value in 2016 by constructing a natural gas liquids plant at Delhi Field in Louisiana, executing a joint venture at Grieve Field that will accelerate development without corresponding capital requirements, and divesting of assets that did not fit into our core asset profile. The natural gas liquids plant at Delhi Field, our largest capital expenditure item of 2016, came online in late 2016, as expected. The plant is working as designed to separate natural gas liquids from the CO_2 recycle stream for sale, generate power from methane, and facilitate higher flood sweep efficiencies.

We also took advantage of disconnected and volatile market conditions in 2016 to significantly reduce our debt, while preserving cash and liquidity. During 2016, we completed a series of privately negotiated debt exchanges and open-market debt repurchases, contributing to a net reduction of our debt principal balance of over $530 million since the end of 2015. When combined with the paydown of our debt with excess cash flow in 2015, we have realized a net debt reduction of nearly $800 million since the end of 2014. In addition to these debt reduction transactions, while managing our capital spending within cash flow, we have maintained nearly $675 million of liquidity on our bank credit facility, with the potential to issue another $385 million of junior lien debt. We are certainly pleased with the sizable progress we have made in reducing our debt and maintaining our liquidity, but, in the current price environment, our leverage metrics are not where we would like them to be. During 2017, we will continue to evaluate and pursue opportunities to improve our balance sheet and debt metrics, as well as proactively manage our bank credit facility to preserve our liquidity.

Looking forward, we are excited with the projects we have planned for 2017. In mid-February 2017, we announced an increase in our estimated capital budget from $209 million in 2016 to $300 million in 2017, with anticipated spending within, or very close to, our cash flow from operations in 2017, based on market prices at that date. We will continue to maintain flexibility in our capital program to adapt to changes in the oil price outlook, as appropriate. We expect this capital spending level should hold our 2017 average production rate roughly flat with our 2016 exit rate of just under 60,000 barrels of oil equivalent per day, placing us on an upward trajectory to resume modest production growth near the end of 2017 and into 2018. Much of our development capital will be directed toward continued development of our existing tertiary floods, where we have an ample inventory of projects with strong rates of return at current oil prices. In addition to this tertiary spending, a portion of the planned spending will be dedicated to our non-tertiary properties, with a smaller amount directed toward exploitation opportunities. In addition, as Denbury has historically done, we continue to look for acquisition opportunities that could allow us to accelerate growth and expand our inventory of future development opportunities.

To summarize, we are optimistic about what lies ahead. We have made significant improvements in our business over the last couple of years and have a plan in place to return to production growth. While we do not expect oil prices to return to the same levels we realized a few years ago, the market is showing signs of stability, and the adjustments made to our business over the past two years have made Denbury a stronger company. We believe that our strong base of long-lived low-decline oil assets, strategic CO_2 supply and distribution capacity, and unique enhanced oil recovery expertise all combine to set the stage for a great future for Denbury.

Sincerely,

Phil Rykhoek
Chief Executive Officer
March 30, 2017

DENBURY'S CO_2 CYCLE

Step 1

CO_2 SOURCES & CAPTURE

The first step in implementing a carbon dioxide enhanced oil recovery ("CO_2 EOR") project is to secure access to substantial volumes of CO_2. Denbury sources CO_2 both from naturally-occurring underground reservoirs and from industrial sources which capture, process and then compress the CO_2 for delivery into a pipeline network. The CO_2 captured from industrial sources (which is sometimes referred to as anthropogenic or man-made CO_2) could otherwise be released into the atmosphere.

Step 2

CO_2 TRANSPORTATION

The second step 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 naturally- occurring CO_2 and CO_2 from industrial sources to our tertiary fields. Between 2014 and 2016 we utilized an average of more than 135 million cubic feet of CO_2 from industrial sources per day and anticipate additional CO_2 from industrial sources from currently planned or future construction of facilities in our Gulf Coast region.

Step 3

CO_2 INJECTION

The third step is to inject the CO_2 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 155 million barrels of oil that may not have otherwise been recovered.

Step 4

CO_2 EOR BENEFITS & STORAGE

CO_2 EOR operations provide considerable economic and environmental benefits. The economic benefits of CO_2 EOR include the creation of jobs due to investments required to implement and operate a CO_2 EOR project, along with tax payments to local governments. Our CO_2 EOR operations provide an environmentally responsible method of utilizing CO_2 for the primary purpose of oil recovery, that also results in the incidental underground storage of CO_2, while also making our nation more energy secure.

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

2016 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, 2016
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

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 the definitions 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 Rule 12b-2 of the Act). 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 $1,394,129,744.

The number of shares outstanding of the registrant's Common Stock as of January 31, 2017, was 398,146,090.

DOCUMENTS INCORPORATED BY REFERENCE

Document:	Incorporated as to:
1. Notice and Proxy Statement for the Annual Meeting of Stockholders to be held May 24, 2017.	1. Part III, Items 10, 11, 12, 13, 14

Denbury Resources Inc.

2016 Annual Report on Form 10-K
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Denbury Resources Inc.

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 or CO_2.
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. In the context of our oil and natural gas production, EOR is also referred to as tertiary 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.
Mcf	One thousand cubic feet of natural gas or CO_2 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 or CO_2 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 or CO_2.
MMcf/d	One million cubic feet of natural gas or CO_2 produced per day.
Noncash fair value gains (losses) on commodity derivatives	The net change during the period in the fair market value of commodity derivative positions. Noncash fair value gains (losses) on commodity derivatives is a non-GAAP measure and makes up only a portion of "Derivatives expense (income)" in the Consolidated Statements of Operations, which also includes the impact of settlements on commodity derivatives during the period. Its use is further discussed in *Management's Discussion and Analysis of Financial Condition and Results of Operations – 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 does not purport to represent the fair value of our oil and natural gas reserves; 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 or CO_2.
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?SID=2d916841db86d079fa060fa63b08d34e&mc=true&node=se17.3.210_14_610&rgn=div8.

Denbury Resources Inc.

PART I

Item 1. Business and Properties

GENERAL

Denbury Resources Inc., a Delaware corporation, is an independent oil and natural gas company with 254.5 MMBOE of estimated proved oil and natural gas reserves as of December 31, 2016, of which 97% is oil. 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 properties through a combination of exploitation, drilling and proven engineering extraction practices, with the most significant emphasis relating to CO_2 enhanced oil recovery operations.

As part of our corporate strategy, we are committed to strong financial discipline, efficient operations and creating long-term value for our shareholders through the following key principles:

- target 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;
- secure 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;
- exercise financial discipline by attempting to balance our development capital expenditures with our cash flows from operations; and
- attract 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, 2016, we had 1,058 employees, 577 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 website, www.denbury.com, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. The public may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains a website, http://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.

2016 BUSINESS DEVELOPMENTS

Oil prices generally constitute the single largest variable in our operating results. Oil prices have historically been volatile, with NYMEX oil prices ranging from \$26 to \$107 per Bbl over the last three calendar years, with prices in February 2016 representing the lowest level in over 14 years. Although realized prices have increased from the lows experienced during the first quarter of 2016, our focus continues to remain on cost reductions and preserving liquidity. Our 2016 business developments included the following:

- Generated \$219.2 million of cash flow from operations (which amount includes \$84.2 million of receipts on settlements of commodity derivatives) in 2016, which was \$10.6 million higher than our incurred development capital expenditures (\$208.6 million).

- Reduced our cash operating costs, including corporate overhead and interest, to approximately $34 per BOE during 2016, a 7% decrease from similar levels during 2015, and reflects improved CO_2 efficiency resulting in a 32% decrease in CO_2 usage between 2015 and 2016.

- Completed a series of privately negotiated debt exchanges and open-market debt repurchases, contributing to a net reduction of our debt principal balance of approximately $530.4 million during 2016. As a result of the reduction in our average debt outstanding, cash interest expense also decreased $11.5 million between 2015 and 2016.

- Generated average total production of 64,003 BOE/d in 2016, an 11% decrease from 2015 production levels when adjusted for asset sales, despite reducing 2016 development capital spending to approximately half of 2015 levels.

- Modified certain of our financial performance covenants applicable to the 2016, 2017 and 2018 periods to provide more flexibility in managing our balance sheet, the credit extended by our lenders, and continuing compliance with financial performance covenants in this low oil price environment. In addition, maintained the $1.05 billion borrowing base under our senior secured bank credit facility, providing us with significant liquidity.

- Completed construction of a natural gas liquids extraction plant at Delhi Field, providing us with the ability to sell natural gas liquids from the produced stream, improve the efficiency of the CO_2 flood, and utilize extracted methane to power the plant and reduce field operating expenses.

- Revised the joint venture arrangement at Grieve Field to provide for our joint venture partner to fund up to $55 million of the remaining estimated capital to complete development of the facility and fieldwork in exchange for a 14% higher working interest and a disproportionate share of revenues from the first 2 million barrels of production.

- Completed a process of evaluating our assets with a goal of increasing the value of both existing assets and future projects by optimizing field operational and development plans, identifying exploitation opportunities, reducing CO_2 injection volumes through increased efficiency, and reducing costs.

2017 BUSINESS OUTLOOK

Beginning in mid-2016, NYMEX oil prices reversed the previous sustained downward trend, increasing to per-barrel prices in the low $50's in late 2016 and early 2017. While these NYMEX oil prices are an improvement from the lows experienced in February 2016, we continue to exercise caution when determining capital budgets and finalizing field development plans, as our primary focus continues to be on preserving our financial strength and flexibility. Given expectations around oil prices using 2017 NYMEX oil futures and our current hedging levels, our 2017 capital spending has initially been budgeted at approximately $300 million, excluding capitalized interest and acquisitions, an increase of 44% over 2016 spending levels. With this increased capital spending level, we currently anticipate 2017 average daily production will remain relatively flat with our exit rate in 2016 of roughly 60,000 BOE/d. Based upon our current production forecast and hedges currently in place, using expected average oil prices in the mid-$50's per barrel during 2017, we currently expect that our operations would internally fund all but a minor amount of our 2017 capital spending budget of $300 million. We currently intend to fund any potential shortfall with incremental borrowings on our senior secured bank credit facility, and as of December 31, 2016, we had ample availability on our senior secured bank credit facility to cover any foreseeable cash flow shortfall.

Our capital spending during 2017 will focus primarily on the continued development of our current tertiary floods, with less focus on the development of unproved reserves. Planned development activities presented in the discussions that follow may be delayed or modified during the course of 2017 depending primarily upon oil prices and our level of cash flow to fund such development, and we will continue to evaluate the timing of the development of our inventory of fields and related pipelines and facilities. Additionally, we plan to continue our focus on improving our balance sheet, maintaining and enhancing the efficiencies achieved over the last couple of years and pursuing opportunities to increase or accelerate growth. We believe the market for acquisitions is improving and under the right conditions and terms acquisitions could provide one potential way to enhance our growth. In light of this, we are focusing on acquisition efforts directed at oil properties, preferably in our two areas of operation, in a manner that is accretive and does not significantly increase our leverage or reduce our liquidity.

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

Oil and Natural Gas Reserve Estimates

DeGolyer and MacNaughton ("D&M") prepared estimates of our net proved oil and natural gas reserves as of December 31, 2016, 2015 and 2014 (see the summary of D&M's report as of December 31, 2016, 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.

The following table provides estimated proved reserve information prepared by D&M as of December 31, 2016, 2015 and 2014, as well as PV-10 Values and Standardized Measures for each period. There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and their values, including many factors beyond our control. Proved oil and natural gas reserve quantities and values presented in the table reflect the significant decline in commodity prices beginning in late 2014 and continuing through 2016, whereby the average first-day-of-the-month NYMEX oil price used in estimating our proved reserves declined from $94.99 per Bbl at December 31, 2014, to $42.75 per Bbl at December 31, 2016, and for natural gas declined from $4.30 per MMBtu at December 31, 2014, to $2.55 per MMBtu at December 31, 2016. These commodity price changes contributed to the largest portion of the decline in proved reserves, including a decline of approximately 126 MMBOE (29%) in our proved reserves from December 31, 2014, to December 31, 2015, approximately half of which was attributable to natural gas reserves at Riley Ridge that were reclassified and are no longer considered proved reserves. See also *Oil and Natural Gas Operations – Field Summary Table*, Item 1A, *Risk Factors – Estimating our reserves, production and future net cash flows is difficult to do with any certainty*, and *Supplemental Oil and Natural Gas Disclosures (Unaudited)* to the Consolidated Financial Statements for further discussion of reserve inputs and changes between periods.

	December 31,		
	2016	2015	2014
Estimated proved reserves			
Oil (MBbls)	247,103	282,250	362,335
Natural gas (MMcf) [(1)]	44,315	38,305	452,402
Oil equivalent (MBOE)	254,489	288,634	437,735
Reserve volumes categories			
Proved developed producing			
Oil (MBbls)	170,082	190,422	240,004
Natural gas (MMcf)	40,167	36,150	72,799
Oil equivalent (MBOE)	176,777	196,447	252,137
Proved developed non-producing			
Oil (MBbls)	31,837	32,638	29,373
Natural gas (MMcf)	3,788	1,801	343,622
Oil equivalent (MBOE)	32,468	32,938	86,643
Proved undeveloped			
Oil (MBbls)	45,184	59,190	92,958
Natural gas (MMcf)	360	354	35,981
Oil equivalent (MBOE)	45,244	59,249	98,955
Percentage of total MBOE			
Proved developed producing	69%	68%	57%
Proved developed non-producing	13%	11%	20%
Proved undeveloped	18%	21%	23%

	December 31,		
	2016	2015	2014
Representative oil and natural gas prices [(2)]			
Oil – NYMEX	$ 42.75	$ 50.28	$ 94.99
Natural gas – Henry Hub	2.55	2.63	4.30
Present values (in thousands) [(3)]			
Discounted estimated future net cash flows before income taxes (PV-10 Value) [(4)]	$ 1,541,684	$ 2,318,555	$ 8,748,069
Standardized measure of discounted estimated future net cash flows after income taxes ("Standardized Measure")	$ 1,399,217	$ 1,890,124	$ 5,908,128

(1) The significant decrease in natural gas reserves reflects the decline in commodity prices between December 31, 2014 and 2015. As a result of this decrease, natural gas reserves at Riley Ridge were reclassified and are no longer considered proved reserves, and which reserves totaled approximately 368 Bcf (61 MMBOE) as of December 31, 2014, or approximately 81% of our total proved natural gas reserves at that date.

(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 Item 7, *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 Financial Accounting Standards Board Codification ("FASC"). PV-10 Values and the Standardized Measure are significantly impacted by the oil prices we receive relative to NYMEX oil prices (our NYMEX oil price differential). The weighted-average oil price differentials utilized were $3.39 per Bbl below representative NYMEX oil prices as of December 31, 2016, compared to $2.17 per Bbl below NYMEX oil prices as of December 31, 2015, and $3.10 per Bbl below NYMEX oil prices as of December 31, 2014.

(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 $142.5 million at December 31, 2016; $428.4 million at December 31, 2015; and $2.84 billion at December 31, 2014. 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, to assess the potential return on investment in our oil and natural gas properties, and to perform our impairment testing of oil and natural 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 Abbreviation*s 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.

Our proved non-producing reserves primarily relate to reserves that are to be recovered from productive zones that currently require a response to performance modifications before they can be classified as proved developed producing. Since a majority of our properties are in areas with multiple pay zones, these properties may have both proved producing and proved non-producing reserves.

As of December 31, 2016, our estimated proved undeveloped reserves totaled approximately 45.2 MMBOE, or approximately 18% of our estimated total proved reserves, a decline of 14.0 MMBOE from December 31, 2015 levels for these reserves, which changes are discussed below. Approximately 91% (41 MMBOE) of our proved undeveloped oil reserves relate to our CO_2 tertiary operations. We generally 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. As of December 31, 2016, 12.6 MMBOE of our total proved undeveloped reserves are not scheduled to be developed within five years of initial booking, all 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.

During 2016, we spent approximately $45 million to convert 5.9 MMBOE of proved undeveloped reserves to proved developed reserves, primarily related to continued tertiary development activities at Delhi Field, as well as non-tertiary development at Cedar Creek Anticline ("CCA"). Other changes during 2016 included adding 3.9 MMBOE of proved undeveloped reserves primarily related to our tertiary operations at Heidelberg Field; reclassifying 6.7 MMBOE of proved undeveloped reserves to unproved reserves pursuant to the five-year development rule established by the SEC primarily due to changes in our development plans; and recognizing other net downward proved undeveloped reserve revisions of 5.3 MMBOE, primarily the result of reserves that were determined to be uneconomic based on 2016 average oil and natural gas prices used in estimating our proved reserves.

During 2016, we provided oil and natural gas reserve estimates for 2015 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, 2015.

Internal Controls Over Reserve Estimates

Reserve information in this report is based on estimates prepared by 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 Master of Science degree in Petroleum Engineering from the University of Texas in 1975, and he has in excess of 37 years of experience in oil and gas reservoir studies and evaluations. Our President and Chief Operating Officer is primarily responsible for overseeing the independent petroleum engineering firm during the process. Our President and Chief Operating Officer has a Bachelor of Science degree in Engineering, Civil Specialty, from the Colorado School of Mines and over 27 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 President and Chief Operating Officer. In addition, our Board of Directors' Reserves and Health, Safety and Environmental ("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 more than 35 years of industry experience, with responsibilities including reserves preparation and approval.

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 are situated in Montana, North Dakota and Wyoming. Our primary focus is increasing the value of our properties through a combination of exploitation, drilling and proven engineering extraction practices, with the most significant emphasis relating to CO_2 EOR operations. Our current portfolio of CO_2 EOR projects provides us significant oil production and reserve growth potential in the future, assuming crude oil prices are at levels that support the development of those projects.

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. We began operations in the Rocky Mountain region in 2010 in connection with, and following, our merger with Encore Acquisition Company ("Encore"). In the Gulf Coast region, we own what is, to our knowledge, the region's only significant naturally occurring source of CO_2, and these large volumes of naturally occurring CO_2 give us a significant competitive advantage in this area. In the Rocky Mountain region, we own an overriding royalty interest equivalent to an approximate one-third ownership interest in ExxonMobil Corporation's ("ExxonMobil's") CO_2 reserves in LaBarge Field in southwestern Wyoming. In addition to the sources of CO_2 we currently own, we purchase and use CO_2 captured from industrial sources which could otherwise be released into the atmosphere (sometimes referred to as anthropogenic, man-made or industrial-source CO_2) in our tertiary operations. These industrial sources of CO_2 help us recover additional oil from mature oil fields and, we believe, also provide an economical way to reduce atmospheric CO_2 emissions through the concurrent underground storage of CO_2 which occurs as part of our oil-producing EOR operations.

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, 2016, and average daily production for 2016, all based on Denbury's net revenue interest ("NRI"). The reserve estimates presented were prepared by D&M, 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* above and *Supplemental Oil and Natural Gas Disclosures (Unaudited)* to the Consolidated Financial Statements.

	Proved Reserves as of December 31, 2016 (1)					2016 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 2016 NRI
Tertiary oil and gas properties								
Gulf Coast region								
Mature properties (3)	17,466	—	17,466	6.9%	92,438	9,040	—	74.1%
Delhi	20,430	—	20,430	8.0%	194,197	4,155	—	57.8%
Hastings	32,498	—	32,498	12.8%	220,883	4,829	—	79.7%
Heidelberg	24,325	—	24,325	9.6%	105,001	5,128	—	81.3%
Oyster Bayou	15,097	—	15,097	5.9%	156,315	5,083	—	87.0%
Tinsley	20,168	—	20,168	7.9%	124,502	7,192	—	81.7%
Total Gulf Coast region	129,984	—	129,984	51.1%	893,336	35,427	—	76.3%
Rocky Mountain region								
Bell Creek	18,854	—	18,854	7.4%	50,464	3,121	—	84.7%
Total Rocky Mountain region	18,854	—	18,854	7.4%	50,464	3,121	—	84.7%
Total tertiary properties	148,838	—	148,838	58.5%	943,800	38,548	—	76.9%
Non-tertiary oil and gas properties								
Gulf Coast region								
Texas	13,588	9,855	15,231	6.0%	106,393	4,153	4,516	75.9%
Mississippi and other	4,385	12,474	6,464	2.5%	18,172	781	3,583	19.5%
Total Gulf Coast region	17,973	22,329	21,695	8.5%	124,565	4,934	8,099	49.8%
Rocky Mountain region								
Cedar Creek Anticline (4)	78,157	15,314	80,709	31.7%	456,764	16,051	1,630	79.3%
Other	2,135	6,672	3,247	1.3%	16,555	1,082	4,571	60.2%
Total Rocky Mountain region	80,292	21,986	83,956	33.0%	473,319	17,133	6,201	77.5%
Total non-tertiary properties	98,265	44,315	105,651	41.5%	597,884	22,067	14,300	68.2%
Total continuing properties	247,103	44,315	254,489	100.0%	$ 1,541,684	60,615	14,300	73.6%
Property sales								
Williston Assets	—	—	—	—	—	825	233	
Other properties divested	—	—	—	—	—	—	845	
Company Total	247,103	44,315	254,489	100.0%	1,541,684	61,440	15,378	

(1) The above reserve estimates were prepared in accordance with FASC Topic 932, *Extractive Industries – Oil and Gas*, using the arithmetic averages of the first-day-of-the-month NYMEX commodity price for each month during 2016, which were $42.75 per Bbl for crude oil and $2.55 per MMBtu for natural gas.

(2) PV-10 Value is a non-GAAP measure and is different from the GAAP measure, the 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 $1.4 billion at December 31, 2016. 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* above. The information used to calculate the 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) Mature properties include Brookhaven, Cranfield, Eucutta, Little Creek, Mallalieu, Martinville, McComb and Soso fields in Mississippi and Lockhart Crossing Field 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 under 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. 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 believe our investments, experience and acquired knowledge give us a strategic and competitive advantage in the areas in which we operate. We apply what we have learned and developed over the years to improve and increase sweep efficiency within the CO_2 EOR projects we operate.

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 more heavily on CO_2 EOR and, over time, transformed our strategy to focus primarily on owning and operating oil fields that are well suited for CO_2 EOR projects. 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. 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.

Our tertiary operations have grown so that (1) 59% of our proved reserves at December 31, 2016 are proved tertiary oil reserves; (2) 60% of our 2016 total production was related to tertiary oil operations (on a BOE basis); and (3) 80% of our 2016 capital expenditures (excluding acquisitions) were related to our tertiary oil operations. At year-end 2016, the proved oil reserves in our tertiary recovery oil fields had an estimated PV-10 Value of approximately $943.8 million, or 61% 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 pipelines and production facilities is greater than in primary oil recovery in most circumstances, 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) reasonable return metrics at our anticipated long-term prices, (3) limited competition for this recovery method in our geographic regions and a strategic advantage due to our ownership of the CO_2 reserves and CO_2 pipeline infrastructure, (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 CO_2 captured from industrial sources in the same underground formations that 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. Together with the related CO_2 pipeline infrastructure, Jackson Dome provides us a significant strategic advantage in the acquisition of 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 of Jackson Dome to approximately 5.3 Tcf as of December 31, 2016. The proved CO_2 reserve estimates are based on a gross (8/8ths) basis, of which our net revenue interest is approximately 4.2 Tcf, and is included in the evaluation of proved CO_2 reserves prepared by D&M, an independent petroleum engineering consulting firm. 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 our proved reserves, we estimate that we have 1.2 Tcf of probable CO_2 reserves at Jackson Dome. While the majority of these probable reserves are located in structures that have been drilled and tested, such reserves are still considered probable 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; or (3) they are reserves associated with increasing the ultimate recovery factor from our existing reservoirs with proved reserves. In addition, a significant portion of these probable reserves at Jackson Dome are located in undrilled structures where we have sufficient subsurface and seismic data indicating geophysical attributes that, coupled with our historically high drilling success rate, provide a reasonably high degree of certainty that CO_2 is present.

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. As part of our innovation and improvement initiative, we have identified fields where we have been able to reduce CO_2 injections without significantly impacting production. As such, we have been able to reduce injected CO_2 volumes in the Gulf Coast region by 23% when comparing injection levels in the fourth quarter of 2016 to those in the prior year fourth quarter. We expect our current proved reserves of CO_2, coupled with a risked drilling program at Jackson Dome and CO_2 expected to be captured from industrial sources, to provide sufficient quantities of CO_2 for us to develop our proved and probable EOR reserves in the Gulf Coast region. 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 the CO_2 that remains in that field's reservoir and utilize it for oil production in another field's tertiary flood.

In the Gulf Coast region, approximately 85% of our average daily CO_2 produced from Jackson Dome or captured from industrial sources in 2016 was used in our tertiary recovery operations, compared to 88% in 2015 and 91% in 2014, with the balance delivered to third-party industrial users. During 2016, we used an average of 462 MMcf/d of CO_2 (including CO_2 captured from industrial sources) for our tertiary activities.

Gulf Coast CO_2 Captured from Industrial Sources. In addition to our natural source of CO_2, we are currently party to three long-term contracts to purchase CO_2 from industrial plants. We have purchased CO_2 from an industrial facility in Port Arthur, Texas since 2012 and from an industrial facility in Geismar, Louisiana since 2013, which currently supply approximately 55 MMcf/d of CO_2 to our EOR operations. We currently expect to begin purchasing CO_2 from Mississippi Power's Kemper County Energy Facility during the first half of 2017, which could more than double the amount of CO_2 we currently utilize from industrial sources. Additionally, we are in ongoing discussions with other parties who have plans to construct plants near the Green Pipeline. One of these projects includes construction of a methanol plant in Lake Charles, Louisiana, which is currently in the project financing stage of development. If the project is successfully financed in 2017, we would not expect first deliveries of CO_2 from the plant until 2021 at the earliest.

In October 2015, the Environmental Protection Agency ("EPA") finalized a rule – *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units* (also known or commonly referred to as the "Clean Power Plan") – that would impose limits on greenhouse gas emissions from new and existing U.S. electric generation units. The Clean Power Plan in its current form contains requirements which would likely impact our ability to purchase power plant CO_2 for our EOR operations from Mississippi Power's Kemper County Energy Facility. The Clean Power Plan has been challenged by various states, trade associations, companies (including Denbury) and environmental groups. On February 9, 2016, the U.S. Supreme Court stayed the implementation of the Clean Power Plan pending resolution of various challenges to the rule. On September 27, 2016, an *en banc* panel of the U.S. Court of Appeals for the District of Columbia Circuit heard oral argument on the merits of the various challenges to the Clean Power Plan. A decision could be issued at any time. In the meantime, the Supreme Court's stay of the rule is in place and is expected to remain so until it grants certiorari and issues its own decision on the Plan, possibly as late as summer 2018. Additionally, the Trump administration has announced its intention to revise or rescind the Clean Power Plan. Given the Clean Power Plan's status as a "final rule," any change or revocation would likely involve a new rule-making process or Congressional action, the timing and details of which cannot be predicted. Although we do not believe the Clean Power Plan will impact our ability to take CO_2 from Mississippi Power's Kemper County Energy Facility in the near term, it could limit our ability to take CO_2 in the future if upheld and maintained in effect.

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 possible legislation or regulatory orders pertaining to 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 CO_2 source. Since 2001, we have acquired or constructed nearly 750 miles of CO_2 pipelines, and as of December 31, 2016, we have access to nearly 950 miles of CO_2 pipelines, which gives us the ability to deliver CO_2 throughout the Gulf Coast region. In addition to the NEJD CO_2 pipeline, the major pipelines in the Gulf Coast region 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 also includes the CO_2 we are receiving from the industrial facilities in Port Arthur, Texas and Geismar, Louisiana, and we 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 this area.

Tertiary Properties with Tertiary Production and Proved Tertiary Reserves at December 31, 2016

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 23% of our total 2016 CO_2 EOR production and approximately 12% 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.

Delhi Field. Delhi Field is located east of Monroe, Louisiana. In May 2006, we purchased our initial interest in Delhi for \$50 million. 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 Field in the fourth quarter of 2016 averaged 4,387 Bbls/d, up from 3,898 Bbls/d in the fourth quarter of 2015. During late 2016, we completed construction of a natural gas liquids extraction plant, which provides us with the ability to sell natural gas liquids from the produced stream, improve the efficiency of the CO_2 flood, and utilize extracted methane to power the plant and reduce field operating expenses. Our 2017 development capital budget includes investing approximately \$20 million in this field, primarily related to continued phase development and infill drilling.

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 2016, tertiary production from Hastings Field averaged 4,552

Bbls/d, compared to 5,082 Bbls/d in the fourth quarter of 2015. Our 2017 development capital budget includes investing approximately $30 million in this field primarily related to continued tertiary development opportunities and conformance work.

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 we began flooding the Christmas and Tuscaloosa zones in 2013 and 2014, respectively. During the fourth quarter of 2016, tertiary production at Heidelberg Field averaged 4,924 Bbls/d, compared to 5,635 Bbls/d in the fourth quarter of 2015. Our future plans for Heidelberg Field include continued development of the East and West Heidelberg Units, including an expansion of our Tuscaloosa development and Christmas zone 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, the ultimate timing of which will depend upon future oil prices or revised development plans. Our 2017 development capital budget includes investing approximately $35 million in this field, primarily related to developing portions of the Christmas Yellow sand in East Heidelberg and conformance work.

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, and 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 began CO_2 injections into Oyster Bayou Field in the second quarter of 2010, commenced tertiary production in the fourth quarter of 2011 from the Frio A-1 zone, and booked initial proved tertiary reserves for the field in 2012. In 2014, we completed development of the Frio A-2 zone. During the fourth quarter of 2016, tertiary production at Oyster Bayou Field averaged 4,988 Bbls/d, compared to 5,831 Bbls/d in the fourth quarter of 2015. Production from Oyster Bayou Field is believed to have peaked during 2015.

Tinsley Field. We acquired Tinsley Field in 2006. This Mississippi field was discovered and first developed in the 1930s and is separated by different fault blocks. As is the case with the majority of fields in Mississippi, Tinsley Field produces from multiple reservoirs. Our CO_2 enhanced oil recovery operations at Tinsley Field 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 and substantially completed development of the Woodruff formation during 2014. During the fourth quarter of 2016, average tertiary oil production from the field was 6,786 Bbls/d, compared to 7,522 Bbls/d in the fourth quarter of 2015. Although production from Tinsley Field is believed to have peaked in 2015, we continue to evaluate future potential investment opportunities in this field. Our 2017 development capital budget includes investing approximately $15 million in this field, primarily related to improvements at the recycle facility.

Future Tertiary Properties with No Tertiary Production or Proved Tertiary Reserves at December 31, 2016

Webster Field. We acquired our interest in Webster Field in the fourth quarter of 2012. 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, 2016, Webster Field had estimated proved non-tertiary reserves of approximately 2.6 MMBOE, net to our interest. During the fourth quarter of 2016, non-tertiary production at Webster Field averaged 828 BOE/d, compared to 1,001 BOE/d in the fourth quarter of 2015. 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 completed a nine-mile lateral between the Green Pipeline and Webster Field, which will eventually deliver CO_2 to the field. The timing of CO_2 injections at Webster Field is primarily dependent upon future oil prices.

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 7.0 MMBOE at December 31, 2016, net to our interest, all of which are proved developed. During the fourth quarter of 2016, production at Conroe Field averaged 2,281 BOE/d, compared to 2,889 BOE/d in the fourth quarter of 2015.

To initiate a CO_2 flood at Conroe Field, a pipeline must be constructed so that CO_2 can be delivered to the 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. Our current plan for initiating a CO_2 flood at Conroe Field is scheduled several years from now, the timing of which may change depending on future oil prices and pipeline construction.

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 4.0 MMBOE at December 31, 2016, net to our interest, all of which are proved developed. During the fourth quarter of 2016, non-tertiary production at Thompson Field averaged 1,344 BOE/d net to our interest, compared to 1,508 BOE/d in the fourth quarter of 2015. Thompson Field is geologically similar to Hastings Field, producing oil from the Frio zone at similar depths, and we therefore believe it has CO_2 EOR potential. 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. The timing of CO_2 injections at Thompson Field is primarily dependent upon future oil prices.

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 sale and exchange transaction with ExxonMobil. Our interest at Riley Ridge (discussed below) is also produced from the LaBarge Field. LaBarge Field is located in southwestern Wyoming.

During 2016, we received an average of approximately 63 MMcf/d of CO_2 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 that we could receive up to 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 use in our Rocky Mountain region CO_2 floods. As of December 31, 2016, our interest in LaBarge Field consisted of approximately 1.2 Tcf of proved CO_2 reserves.

Riley Ridge. The Riley Ridge Federal Unit is also located in southwestern Wyoming and produces gas from the same LaBarge Field. We own 100% of the operating interests in Riley Ridge, as well as a gas processing facility. We acquired the Riley Ridge Federal Unit and the associated gas processing facility with the intent to separate for sale the natural gas and helium from the full well stream after construction of the gas processing facility was completed, and ultimately for the purpose of gaining a source of CO_2 to utilize in flooding our fields in the Rocky Mountain region. Subsequently, issues arose related to contractor performance and design failure that caused significant delays and incremental costs to complete the facility. We placed the gas processing facility into service during the fourth quarter of 2013, and we were successful in running the facility for part of 2014 before additional issues arose related to optimal operation of the facility and sulfur build-up in the gas supply wells. In mid-2014, the gas processing facility was shut-in and to date remains shut-in. We plan to continue engineering work and analysis in 2017 to determine if there are alternative options to remediate the sulfur build-up in the gas supply wells and to assess our ability to reduce the costs thereof; however, the time of completion and results of such analysis are currently uncertain.

Other Rocky Mountain CO_2 Sources. While Riley Ridge is a potential source of CO_2 for flooding our fields in the Rocky Mountain region, we have formed alternative plans to develop our future CO_2 EOR floods, which CO_2 volumes we currently anticipate could be supplied through existing CO_2 sources. We began purchasing and receiving CO_2 from the ConocoPhillips-operated Lost Cabin gas 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.

Greencore Pipeline. The 20-inch Greencore Pipeline in Wyoming is the first CO_2 pipeline we constructed in the Rocky Mountain region. We plan to use the pipeline as our trunk line in the Rocky Mountain region, eventually connecting our various Rocky Mountain region CO_2 sources (see *Rocky Mountain Region CO_2 Sources and Pipelines* above) to the Cedar Creek Anticline in eastern Montana and western North Dakota. The initial 232-mile section of the Greencore Pipeline begins at the ConocoPhillips-operated 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 ConocoPhillips-operated Lost Cabin gas plant during the first quarter of 2013. During 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 enables 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, 2016

Bell Creek Field. We acquired our interest in Bell Creek Field in southeast Montana as part of the Encore merger in 2010. 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. During 2013, we began first CO_2 injections into Bell Creek Field, recorded our first tertiary oil production, and booked initial proved tertiary reserves. Tertiary production, net to our interest, during the fourth quarter of 2016 averaged 3,269 Bbls/d of oil, compared to 2,806 Bbls/d in the fourth quarter of 2015, as production has steadily grown from the initial production response in the third quarter of 2013. Our 2017 development capital budget includes investing approximately $25 million in this field primarily related to expansion of the flood into new phases. We expect production from this field will continue to increase during 2017.

Future Tertiary Properties with No Tertiary Production or Proved Tertiary Reserves at December 31, 2016

Cedar Creek Anticline. CCA is the largest potential EOR property that we own and currently our largest producing property, contributing approximately 26% of our 2016 total production. 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 different operating 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 for $1.0 billion, adding 42.2 MMBOE of incremental proved reserves at that date. Production from CCA, net to our interest, averaged 15,186 BOE/d during the fourth quarter of 2016, compared to production during the fourth quarter of 2015 of 17,875 BOE/d. The non-tertiary proved reserves associated with CCA were 80.7 MMBOE, net to our interest, as of December 31, 2016.

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 the future, we plan to perform minor conformance work at the field to minimize production declines, the timing of which will depend on future oil prices. Our current plan for initiating a CO_2 flood at CCA is scheduled several years from now, the timing of which may change depending on future oil prices, pipeline permitting and sources and availability of CO_2. In addition to the future plans to flood CCA with CO_2, we are also creating plans for exploitation opportunities that exist across the field. Our 2017 development capital budget includes investing approximately $25 million in this field primarily related to field infrastructure upgrades.

Grieve Field. In the second quarter of 2011, we entered into a farm-in agreement, under which we obtained 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 Grieve Field in the fourth quarter of 2012. During the third quarter of 2016, the Company and its joint venture partner in Grieve Field reached an agreement to revise the joint venture arrangement between the parties for the continued development of the field. The revised agreement provides for our partner to fund up to $55 million of the remaining estimated capital to complete development of the facility and fieldwork in exchange for a 14% higher working interest and a disproportionate sharing of revenue from the first 2 million barrels of production. As a result of this agreement, our working interest in the field was reduced from 65% to 51%. This arrangement will accelerate the remaining development of the facility and fieldwork, and we currently anticipate first tertiary production by the middle of 2018.

Hartzog Draw Field. We acquired our interest in Hartzog Draw Field in the fourth quarter of 2012. 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 3.2 MMBOE at December 31, 2016, net to our interest, 1.0 MMBOE of which relate to the natural gas producing Big George coal zone. During the fourth quarter of 2016, non-tertiary production averaged 1,665 BOE/d, compared to 2,212 BOE/d in the fourth quarter of 2015. We successfully completed 5 wells in Hartzog Draw Field in 2014; however, we have temporarily suspended the non-tertiary development of Hartzog Draw Field in light of the recent oil price environment. We believe the oil reservoir characteristics of Hartzog Draw Field make it well suited for CO_2 EOR in the future. We currently plan to initiate a CO_2 flood at Hartzog Draw Field several years from now, the timing of which is dependent on future oil prices.

Other Non-Tertiary Oil Properties

Despite the majority of our oil and natural gas properties discussed above consisting of either existing or planned future tertiary floods, we do also produce oil and natural gas either from fields in both our Gulf Coast and Rocky Mountain regions that are not amenable to EOR or from 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. Continuing production from these other non-tertiary properties totaled 2,035 BOE/d during the fourth quarter of 2016, compared to 3,444 BOE/d during the fourth quarter of 2015.

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, 2016:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Gulf Coast region	245,869	199,089	284,606	16,712	530,475	215,801
Rocky Mountain region	324,489	298,336	190,129	75,041	514,618	373,377
Total	570,358	497,425	474,735	91,753	1,045,093	589,178

The percentage of our net undeveloped acreage that is subject to expiration over the next three years, if not renewed, is approximately 2% in 2017, 11% in 2018 and 25% in 2019.

Productive Wells

The following table sets forth our gross and net productive oil and natural gas wells as of December 31, 2016:

	Producing Oil Wells		Producing Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Operated wells						
Gulf Coast region	1,262	1,174	161	149	1,423	1,323
Rocky Mountain region	945	898	281	144	1,226	1,042
Total	2,207	2,072	442	293	2,649	2,365
Non-operated wells						
Gulf Coast region	38	2	—	—	38	2
Rocky Mountain region	22	5	3	1	25	6
Total	60	7	3	1	63	8
Total wells						
Gulf Coast region	1,300	1,176	161	149	1,461	1,325
Rocky Mountain region	967	903	284	145	1,251	1,048
Total	2,267	2,079	445	294	2,712	2,373

Drilling Activity

The following table sets forth the results of our drilling activities over the last three years. As of December 31, 2016, we had 2 wells in progress.

	Year Ended December 31,					
	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells [(1)]						
Productive [(2)]	—	—	—	—	—	—
Non-productive [(3)]	—	—	—	—	—	—
Development wells [(1)]						
Productive [(2)]	—	—	16	15	59	56
Non-productive [(3)(4)]	—	—	—	—	—	—
Total	—	—	16	15	59	56

(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 2016, 2015 and 2014, an additional 1, 6 and 43 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, 2016, 2015 and 2014:

	Year Ended December 31,		
	2016	2015	2014
Net sales volume			
Gulf Coast region			
Oil (MBbls)	14,772	16,783	17,259
Natural gas (MMcf)	3,274	5,187	4,855
Total Gulf Coast region (MBOE)	15,318	17,648	18,068
Rocky Mountain region			
Oil (MBbls)	7,715	8,462	8,513
Natural gas (MMcf)	2,354	2,906	3,524
Total Rocky Mountain region (MBOE)	8,107	8,946	9,100
Total Company (MBOE)	23,425	26,594	27,168
Average sales prices – excluding impact of derivative settlements			
Gulf Coast region			
Oil (per Bbl)	$ 41.99	$ 49.34	$ 94.67
Natural gas (per Mcf)	2.04	2.48	4.31
Rocky Mountain region			
Oil (per Bbl)	$ 39.44	$ 43.25	$ 82.75
Natural gas (per Mcf)	1.90	2.11	3.73
Total Company			
Oil (per Bbl)	$ 41.12	$ 47.30	$ 90.74
Natural gas (per Mcf)	1.98	2.35	4.07
Average production cost (per BOE sold) (1)			
Gulf Coast region (2)	$ 18.42	$ 19.51	$ 24.92
Rocky Mountain region	16.38	19.07	21.69
Total Company (2)	17.71	19.37	23.84

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

(2) Production costs include certain special items, comprised of (1) lease operating expenses and related insurance recoveries recorded to remediate an area of Delhi Field, (2) a reimbursement for a retroactive utility rate adjustment, and (3) other insurance recoveries. If these amounts were excluded, average production costs per BOE for the Gulf Coast region would have totaled $20.29 and $25.31 for the years ended December 31, 2015 and 2014, respectively, and average production costs per BOE for the Company as a whole would have totaled $19.88 and $24.10 for the years ended December 31, 2015 and 2014, respectively.

PRODUCTION AND UNIT PRICES

Further information regarding average production rates, unit sales 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 natural gas sales are made on a day-to-day basis or under short-term contracts at the current area market price. We would not expect the loss of any single purchaser 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, 2016, two purchasers accounted for 10% or more of our oil and natural gas revenues: Plains Marketing LP (20%) and Marathon Petroleum Company (14%). For the year ended December 31, 2015, two purchasers accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company (28%) and Plains Marketing LP (15%). For the year ended December 31, 2014, three purchasers accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company (31%), Plains Marketing LP (13%), and ConocoPhillips (12%).

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 natural gas, the proximity of our oil and natural gas production to pipelines and corresponding markets, 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. As of December 31, 2016, 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

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, crude oil quality and location differentials. The oil differentials we received in the Gulf Coast and Rocky Mountain regions are discussed in further detail below.

Crude oil prices in the Gulf Coast region are impacted significantly by the changes in prices received for our crude oil sold under Light Louisiana Sweet ("LLS") index prices relative to the change in NYMEX prices. Overall, during 2016, we sold approximately 60% of our crude oil at prices based on, or 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 average LLS-to-NYMEX differential (on a trade-month basis) was a positive $1.70 per Bbl during 2016, compared to a positive $3.72 per Bbl during 2015 and a positive $3.88 per Bbl in 2014. During 2016, our light sweet crude oil production in the Gulf Coast region, on average, sold for $1.38 per Bbl below NYMEX, compared to $0.56 per Bbl over NYMEX in 2015 and $1.80 per Bbl over NYMEX in 2014. 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; Wood River, Illinois; and most recently Cushing, Oklahoma. Shipments on some of the pipelines are at or near capacity and may be subject to apportionment. We currently have access to, or have contracted for, 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. 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 markets outside of the region. Therefore, prices in the Rocky Mountain region are further influenced by fluctuations in prices (primarily Brent and LLS) in coastal markets and by available pipeline capacity in the Midwest and Cushing markets. For the year ended December 31, 2016, the discount for our oil production in the Rocky Mountain region averaged $3.97 per Bbl, compared to $5.60 per Bbl during 2015 and $10.19 per Bbl during 2014.

Natural Gas Marketing

We have minimal natural gas production, as 96% of our 2016 average daily production was oil. 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.

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. Prior to the recent downturn in oil prices, the competition for qualified technical personnel had been extensive, and our personnel costs escalated. There were also 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 the evolving regulatory landscape 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, federal and 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. Regulatory requirements and compliance relative to the oil and gas industry increase our costs of doing business and, consequently, affect 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

The Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011, among other things, updated federal pipeline safety standards, increased penalties for violations of such standards, gave the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (the "PHMSA") authority for new damage prevention and incident notification, and directed the PHMSA to prescribe new minimum safety standards for CO_2 pipelines, which safety standards could affect our operations and the costs thereof. While the PHMSA has adopted or proposed to adopt a number of new regulations to implement this act, no new minimum safety standards have been proposed or adopted for CO_2 pipelines.

Both federal and state authorities have in recent years proposed new regulations to limit the emission of greenhouse gasses as part of climate change initiatives. For example, both the EPA and BLM have issued regulations for the control of methane emissions. The EPA has promulgated regulations requiring permitting for certain sources of greenhouse gas emissions, and in May 2016, promulgated final regulations to reduce methane and volatile organic compound emissions from the oil and gas sector. Enforcement of these regulations may impose additional costs related to compliance with new emission limits, as well as inspections and maintenance of several types of equipment used in our operations. Conversely, on February 3, 2017, the U.S. House of Representatives approved a resolution to void a Bureau of Land Management rule restricting methane venting and flaring, which must be approved by the U.S. Senate and signed by the President to take effect.

Natural Gas Gathering Regulations

State and federal 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 and federal 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 laws and regulations or other laws and regulations 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 and human health, 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 greenhouse gas emissions and 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 and other wastes.

In the Rocky Mountain Region, federal agencies' actions based upon their environmental review responsibilities under the National Environmental Policy Act can significantly impact the scope and timing of hydrocarbon development by slowing the timing of individual applications for permits to drill and requests for rights-of-way, and delaying large scale planning associated with region-level resource management plans and project-level master development plans. Given the Trump administration's announced intention to revise or rescind federal regulations promulgated during the Obama administration and to promote fossil fuel development on federal lands, it is possible that there could be an increase in litigation initiated by environmental or citizens groups, state attorneys general, or other elected or appointed officials.

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 2016, we fracture stimulated one water source well at Tinsley Field utilizing water-based fluids with no diesel fuel component. We are currently evaluating the potential to refrac approximately five wells at Hartzog Draw Field during 2017. We are familiar with the laws and regulations applicable to hydraulic fracturing operations and take steps to ensure compliance with these requirements.

Item 1A. Risk Factors

Oil and natural gas prices are volatile. A sustained period of deterioration of oil prices is likely to adversely affect our future financial condition, results of operations, cash flows and the carrying value of our oil and natural gas properties.

Oil prices have historically been volatile, with NYMEX oil prices ranging from $26 to $107 per Bbl over the last three calendar years, with prices in February 2016 representing the lowest level in over 14 years. Even if oil prices recover for a period of time, volatility will remain, and prices could move downward or upward on a rapid or repeated basis, which can make transactions, valuations and business strategies difficult. Our cash flow from operations is highly dependent on the prices that we receive for oil, as oil comprised approximately 96% of our 2016 production and approximately 97% of our proved reserves at December 31, 2016. The prices for oil and natural gas are subject to a variety of 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 and the domestic and foreign supply of oil and natural gas and levels of domestic oil and gas storage;
- the degree to which members of the Organization of Petroleum Exporting Countries maintain oil price and production controls;
- the degree to which domestic oil and natural gas production affects worldwide supply of crude oil or its price;
- worldwide political events, conditions and policies, including actions taken by foreign oil and natural gas producing nations; and
- worldwide economic conditions.

Due to the sustained period of low oil prices, the PV-10 Value of our estimated proved reserves was less than our outstanding indebtedness as of December 31, 2016. If oil prices decline further for an extended period of time, we could be harmed in a number of ways, including:

- lower cash flows from operations may require continued or further reduced levels of capital expenditures;
- reduced levels of capital expenditures in turn could lower our present and future production levels, and lower the quantities and value of our oil and gas reserves, which constitute our major asset;
- our lenders could reduce our borrowing base, and we may not be able to raise capital at attractive rates in the public markets;
- we could be forced to increase our level of indebtedness, issue additional equity, or sell assets;
- we could have difficulty repaying or refinancing our indebtedness;
- we could be required to impair various assets, including a further write-down of our oil and natural gas assets or the value of other tangible or intangible assets;
- construction of plants that produce CO_2 as a byproduct that we can purchase could be delayed or cancelled, thus limiting the amount of industrial-source CO_2 available for use in our tertiary operations; and/or
- our potential cash flows from our commodity derivative contracts that include sold puts could be limited to the extent that oil prices are below the prices of those sold puts.

Furthermore, some or all of our tertiary projects could remain or become uneconomical. We may also decide to suspend future expansion projects, and if prices were to drop below our operating cash break-even points 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, financial condition and reduce our production.

A financial downturn in one or more of the world's major markets could negatively affect our liquidity, business and financial condition.

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 sustained credit crisis, further drops in economic growth rates in China, regional or worldwide increases in tariffs or other trade restrictions, significant international currency fluctuations, a severe economic contraction either regionally or worldwide or turmoil in the global financial system, could materially affect our liquidity, business and financial condition. In the past, conditions such as these have adversely impacted financial markets and have created substantial volatility and uncertainty with the related negative impact on global economic activity. Negative credit market conditions could 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. Negative economic conditions could also adversely affect the collectability of our trade receivables or performance by our suppliers or cause our commodity hedging arrangements to be ineffective if our counterparties are unable to perform their obligations or otherwise seek bankruptcy protection.

Our level of indebtedness could adversely affect the level of our production activities if not materially reduced.

As of December 31, 2016, our outstanding indebtedness consisted of $614.9 million principal amount of 9% Senior Secured Second Lien Notes due 2021, $1.6 billion principal amount of subordinated notes, virtually all of which have maturity dates between 2021 and 2023 at interest rates ranging from 4.625% to 6.375% per annum at a weighted average interest rate of 5.28% per annum, and $301.0 million principal amount outstanding under our bank credit facility. As of February 22, 2017, we have a borrowing base and aggregate lender commitments of $1.05 billion under our bank credit facility and availability with respect to such commitments of $674.7 million. Our bank borrowing base is adjusted semiannually in May and November of each year, and upon requested unscheduled 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. 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 future redetermination lowering our borrowing base could limit availability under our bank credit facility. If the outstanding debt under our bank credit facility were to ever exceed the borrowing base, we would be required to repay the excess amount over a period not to exceed six months.

The level of our indebtedness could have important consequences, including but not limited to the following:

- increasing our vulnerability to general adverse economic and industry conditions;
- impairing our ability to obtain additional financing for working capital, capital expenditures, acquisitions, development activities or general corporate and other purposes;
- potentially restricting us from making acquisitions or exploiting business opportunities;
- reducing our available cash flow if market interest rates increase or if the level of our indebtedness significantly increases;
- requiring dedication of a substantial portion of our cash flows from operations to servicing our indebtedness (so that such cash flows would not be available for capital expenditures or other purposes);
- limiting our ability to borrow additional funds, dispose of assets, pay dividends, fund share repurchases and make certain investments; and/or
- placing us at a competitive disadvantage as compared to our competitors that have less debt.

Additionally, rising interest rates would, among other things, affect our interest costs under our bank credit facility, increase the cost of any new debt financings, or limit our ability to otherwise borrow additional funds on favorable terms.

The debt covenants contained in the agreements governing our outstanding indebtedness may also affect our flexibility in reacting to changes in the economy and in our industry. For example, as our cash flow from operations is highly dependent on the prices that we receive for oil and natural gas, our leverage metrics deteriorated during 2015 and 2016. Between May 2015 and April 2016, we modified certain of our financial performance covenants under our senior secured bank credit facility applicable to the 2016, 2017 and 2018 periods to support continuing compliance with these covenants in this low oil price environment. If oil and natural gas prices remain at current levels for an extended period of time, these metrics could deteriorate further, potentially causing us to not be in compliance with our bank credit facility's covenants. In the future, we may be required to seek further modifications of these covenants, or to further reduce our debt by, among other things, purchasing our subordinated debt in the open market, completing cash tenders for our debt or public or privately negotiated debt exchanges, issuing equity or completing asset sales and other cash-generating activities. We cannot assure you, however, that we will be able to successfully modify these covenants or reduce our debt in the future. For more information on our bank credit facility, see Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Senior Secured Bank Credit Facility*.

Any failure to meet our debt obligations or comply with the debt covenants contained in the agreements governing our outstanding indebtedness could harm our business, financial condition and results of operations.

We expect our cash flows to vary significantly from year to year due to the cyclical nature of our business. A sustained period of low oil prices or their further deterioration may cause us to be unable to make required payments on our indebtedness. If we are unable to generate sufficient cash flows or otherwise obtain funds necessary to make required payments on our indebtedness, or if we otherwise fail to comply with the various covenants governing such indebtedness, especially those in our bank credit facility, we could be in default under such indebtedness. Any such default, if not cured or waived, 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. In addition, any failure to make scheduled payments of interest and principal on our outstanding indebtedness would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness on acceptable terms. 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.

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, among other things, to estimate quantities of oil and natural gas reserves; process and record financial and operating data; analyze seismic and drilling information; process wire transfers and store our banking information; monitor and control pipeline and plant equipment; process and store personally identifiable information of our employees and royalty owners; and communicate with employees, stakeholders and business associates. 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 and/or financial loss. 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.

Although we utilize various procedures and controls to monitor and protect against these threats and to mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing and causing us to 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 procedures and controls or to investigate and remediate any cyber vulnerabilities.

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. In addition, our operations are sometimes near populated commercial or residential areas, which add additional 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. 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. However, 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 may incur significant costs in connection with remedial plugging operations to prevent environmental contamination and to otherwise comply with federal, state and local regulations 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.

Development activities are subject to many risks, including 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 other governmental requirements; and
- the cost of, or shortages or delays in the availability of, drilling rigs, equipment, pipelines and services.

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 revision 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. The representative oil and natural gas prices used in estimating our December 31, 2016 reserves were $42.75 per Bbl for crude oil and $2.55 per MMBtu for natural gas, both of which were adjusted for market differentials by field. Rapid crude oil price declines beginning in late 2014 have resulted in a significant decrease in our proved reserve value, and to a lesser degree, a reduction in our proved reserve volumes, which has caused us to record write-downs due to the full cost ceiling test in 2015 and 2016. As discussed in greater detail below, further declines in oil prices could result in additional write-downs. 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, 2016, approximately 18% 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.

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, state and local governments and the federal government in certain areas. Certain states where we operate have considered or may again consider the adoption of laws or regulations that could limit or eliminate the ability of a pipeline owner or of a state, state's legislature or its administrative agencies 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 that could be listed as threatened or endangered under the Endangered Species Act, which listing could lead to tighter restrictions as to federal land use and other land use where federal approvals are required. 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. Pipeline projects are also subject to heightened levels of scrutiny as a result of public opposition to projects like the Keystone XL and Dakota Access pipelines. This scrutiny has the potential to result in permitting delays, enhanced and prolonged environmental review for pipeline projects, and litigation challenges to regulatory agencies' authorizations of pipeline projects.

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

Unless we can successfully develop our existing reserves and/or 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. For internal organic growth activities, the magnitude of proved reserves that we can book in any given year depends on our progress with new floods and the timing of the production response. 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 continue to be reduced, whether due to current 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 prior to any resulting and associated production and cash flows from these projects, heightening potential capital constraints. If capital expenditures remain at reduced levels, or if outside capital resources become limited, we will not be able to maintain our current production levels.

We have acquired several fields at a substantial cost because we believe that they have significant additional production potential through tertiary flooding, and we may have the opportunity to acquire other oil fields that we believe are tertiary flood candidates, some of which may require significant amounts of capital. If we are unable to successfully develop and produce the potential oil in any 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.

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 portion of our forecasted oil and natural gas production. As of February 22, 2017, we have oil derivative contracts in place covering 39,000 Bbls/d for the first quarter of 2017, 29,000 Bbls/d for the second quarter of 2017, 16,500 Bbls/d for the third quarter of 2017, and 13,000 Bbls/d for the fourth quarter of 2017. Such 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, when the cash benefit from hedges including a sold put is limited to the extent oil prices fall below the price of our sold puts, or when the counterparty to the derivative contract is financially constrained and 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.

Shortages of or delays in the availability 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 the past, during periods of high oil and natural gas prices, we have experienced shortages of oil field and other necessary equipment, including drilling rigs, along with increased prices for such equipment, services and associated personnel. 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 our operations, possibly 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.

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

Our long-term strategy is primarily 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 naturally occurring and industrial-sourced 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, catastrophic pipeline failure or our ability to economically purchase CO_2 from industrial sources. 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.

The development of our naturally occurring CO_2 sources involves the drilling of wells to increase and extend the CO_2 reserves available for use in our tertiary fields. These drilling activities are subject to many of the same drilling and geological risks of drilling and producing oil and gas wells (see *Oil and natural gas development and producing operations involve various risks* above). Furthermore, recent market conditions may cause the delay or cancellation of construction of plants that produce industrial-source CO_2 as a byproduct that we can purchase, thus limiting the amount of industrial-source CO_2 available for our use in our tertiary operations.

We may lose executive officers, key management personnel or other talented employees, 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. Historically, a significant portion of the compensation paid to our executive officers and key management personnel has been through long-term grants of Company stock under our 2004 Omnibus Stock and Incentive Plan (the “2004 Plan”). If the shares reserved under the 2004 Plan are depleted and not replenished, we may be forced to eliminate long-term equity grants, which would negatively impact our ability to attract and retain highly skilled managerial personnel. Replacing long-term equity grants with cash compensation would reduce the cash available to fund capital expenditures. Additionally, in a low oil price environment, we could be susceptible to losing talented non-industry professionals (e.g., accountants, attorneys and human resources personnel). Competition for persons with these skills is intense, and there is no assurance that we will be successful in attracting and retaining such skilled and talented personnel.

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 the protection of human health and the environment, including the protection of endangered species. 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. While the President has indicated that his administration will relax enforcement of and work to repeal certain federal environmental regulations that affect the oil and gas industry, we are currently unable to predict what, if any, changes will be made or their timing.

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

Numerous executive, legislative and regulatory proposals affecting the oil and gas industry have been introduced, are anticipated to be introduced, or are otherwise under consideration, by the President, Congress, state legislatures and various federal and state agencies. While it is currently anticipated that the President and Congress will move away from the trend of proposing stricter standards and increasing oversight and regulation at the federal level, it is possible that other proposals affecting the oil and gas industry could be enacted or adopted in the future, which 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.

The new Presidential administration and Congress have stated that comprehensive U.S. tax reform is a priority and have discussed their intent to pursue major federal tax reform. If major tax revisions are made, it is possible that a number of special tax provisions affecting the oil and gas industry could be changed. The passage of legislation or any other change in U.S. federal income tax law that eliminates, reduces or postpones certain tax deductions that are currently available to us or otherwise increases our taxes could negatively affect the after-tax returns generated on our oil and gas investments, our cash flow or our financial condition and results of operations, even if reduced corporate tax rates are enacted.

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 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. The Dodd-Frank Act, rules promulgated thereunder or new legislation or regulations, could (1) affect the cost, or decrease the liquidity, of energy-related derivatives available to us to hedge against commodity price fluctuations (including through requirements to post collateral), (2) materially alter the terms of derivative contracts, (3) affect 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 due to changes in the derivatives market, our cash flows could become more volatile and less predictable, which could adversely affect our ability to plan for and fund capital expenditures. On the other hand, there is significant uncertainty as to the status of the Dodd-Frank Act, and its regulations and enforcement, growing out of widespread discussion of repealing or scaling back the Dodd-Frank Act – either through legislative or regulatory action; however, it is not possible to determine at this time whether such changes will take place, in what form or to what extent.

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, 2016, two purchasers individually accounted for 10% or more of our oil and natural gas revenues and, in the aggregate, for 34% of such revenues. The loss of a large single purchaser could adversely impact the prices we receive or the transportation costs we incur.

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. Our operations in the coastal areas of the Gulf Coast region may be subjected to adverse weather conditions such as 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, which can also increase costs and have a negative effect on our results of operations.

If commodity prices decline appreciably, we may be required to write down the carrying value of our oil and natural gas properties.

Under full cost accounting rules related to our oil and natural gas properties, we are required each quarter to perform a ceiling test calculation, with the net capitalized costs of our oil and natural gas properties limited to the lower of unamortized cost or the cost center ceiling. The present value of estimated future net revenues from proved oil and natural gas reserves included in the cost center ceiling is based on the average first-day-of-the-month oil and natural gas price for each month during a 12-month rolling period prior to the end of a particular reporting period. During 2015 and 2016, we recorded full cost pool ceiling test write-downs of our oil and natural gas properties totaling \$4.9 billion (\$3.1 billion net of tax) and \$810.9 million (\$508.2 million net of tax), respectively (see Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Write-Down of Oil and Natural Gas Properties* and *Critical Accounting Policies and Estimates – Full Cost Method of Accounting, Depletion and Depreciation and Oil and Natural Gas Properties*). Future material write-downs of our oil and natural gas properties, as well as future impairment of other long-lived assets, could significantly reduce earnings during the period in which such write-down and/or impairment occurs and would result in a corresponding reduction to long-lived assets and equity. See Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies and Estimates*.

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 Arrangements*, and Note 10, *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 business or finances, litigation is subject to inherent uncertainties. Although a single or multiple adverse rulings or settlements could possibly have a material adverse effect on our business or finances, we only accrue for losses from litigation and claims if we determine that a loss is probable and the amount can be reasonably estimated.

Potential Mississippi Environmental Administrative Proceeding

For the past two years, the Company has been in negotiations with the Mississippi Department of Environmental Quality ("MDEQ") that began following receipt of a February 2015 notice from the MDEQ related to a discharge of materials at the West Heidelberg Field in Jasper County, Mississippi in the third quarter of 2013. Based upon recent discussions with the MDEQ, it is currently anticipated that a settlement related to the discharge providing for a monetary fine as a civil penalty will be reached, thus eliminating the need for an administrative proceeding. The Company expects any such fine will not be material to the Company's business or financial condition.

Riley Ridge Helium Supply Contract Claim

As part of our 2010 and 2011 acquisitions of the Riley Ridge Unit and associated gas processing facility that was under construction, we assumed a 20-year helium supply contract under which we agreed to supply to a third-party purchaser the helium separated from the full well stream by operation of the gas processing facility. The helium supply contract provides for the delivery of a minimum contracted quantity of helium, subject to adjustment after startup of the Riley Ridge gas processing facility, with liquidated damages payable if specified quantities of helium are not supplied in accordance with the terms of the contract. The liquidated damages are capped at $8.0 million per contract year and are capped at an aggregate of $46.0 million over the remaining term of the contract. As the gas processing facility has been shut-in since mid-2014, we have not been able to supply helium to the third-party purchaser under the helium supply contract. In a case originally filed in November 2014 by APMTG Helium, LLC, the third-party helium purchaser, in the Ninth Judicial District Court of Sublette County, Wyoming, after a week of trial on the third-party purchaser's claim for multiple years of liquidated damages for non-delivery of volumes of helium specified under the helium supply contract, and on our claim that the contractual obligation is excused by virtue of events that fall within the force majeure provisions in the helium supply contract, the trial was stayed in late February 2017 until a later date yet to be determined by the District Court. The Company plans to continue to vigorously defend its position, but we are unable to predict at this time the outcome of this dispute.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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 well as dividends declared within those periods. Prior to 2014, we had not historically declared or paid dividends on our common stock. As of January 31, 2017, 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 1,993. On February 28, 2017, the last reported sale price of Denbury's common stock, as reported on the NYSE, was $2.71 per share.

	2016			2015		
	High	Low	Dividends Declared Per Share	High	Low	Dividends Declared Per Share
First Quarter	$ 3.66	$ 0.95	$ —	$ 8.78	$ 6.26	$ 0.0625
Second Quarter	4.68	2.01	—	9.20	6.16	0.0625
Third Quarter	3.67	2.62	—	5.74	2.44	0.0625
Fourth Quarter	4.03	2.39	—	4.24	1.89	—

During the first three quarters of 2015, the Company's Board of Directors declared quarterly cash dividends of $0.0625 per common share. In September 2015, in light of the continuing low oil price environment and our desire to maintain our financial strength and flexibility, the Company's Board of Directors suspended our quarterly cash dividend. For further discussion, see Note 6, *Stockholders' Equity*, to the Consolidated Financial Statements. No unregistered securities were sold by the Company during 2016.

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 2016	3,350	$ 2.74	—	$ 210.1
November 2016	11,169	2.95	—	210.1
December 2016	3,061	3.88	—	210.1
Total	17,580		—	

(1) Stock repurchases during the fourth quarter of 2016 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.

(2) In October 2011, we commenced a common share repurchase program, which has been approved for up to an aggregate of $1.162 billion of Denbury common shares by the Company's Board of Directors. This program has effectively been suspended and we do not anticipate repurchasing shares of our common stock as long as current commodity pricing and general economic conditions persist. 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.

Between early October 2011, when we announced the commencement of a common share repurchase program, and December 31, 2016, we repurchased 64.4 million shares of Denbury common stock (approximately 16.0% of our outstanding shares of common stock at September 30, 2011) for $951.8 million, with no repurchases made since October 2015.

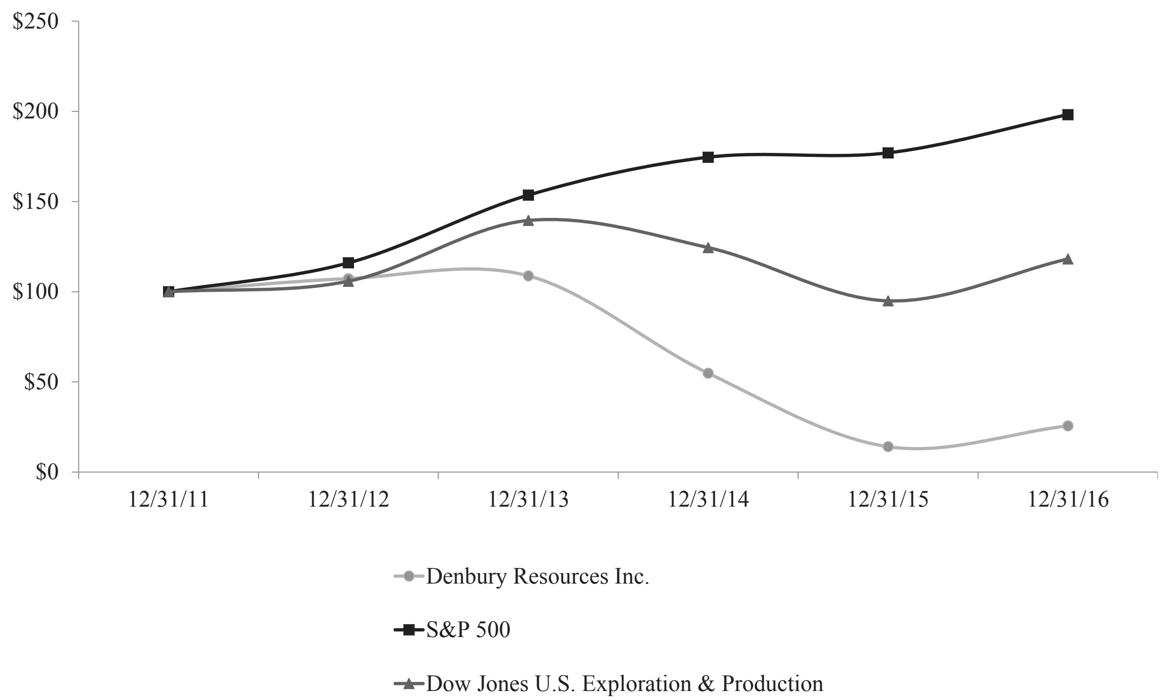
Denbury Resources Inc.

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, 2016, 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, 2011, to December 31, 2016.

COMPARISON OF 5-YEAR CUMULATIVE TOTAL RETURN



	December 31,					
	2011	2012	2013	2014	2015	2016
Denbury Resources Inc.	$ 100	$ 107	$ 109	$ 55	$ 14	$ 26
S&P 500	100	116	154	175	177	198
Dow Jones U.S. Exploration & Production	100	106	140	124	95	118

Item 6. Selected Financial Data

In thousands, except per-share data or otherwise noted	2016	2015	2014	2013	2012
	Year Ended December 31,				
Consolidated Statements of Operations data					
Revenues and other income					
Oil, natural gas, and related product sales	$ 935,751	$ 1,213,026	$ 2,372,473	$ 2,466,234	$ 2,409,867
Other	39,845	44,534	62,732	50,893	46,605
Total revenues and other income	$ 975,596	$ 1,257,560	$ 2,435,205	$ 2,517,127	$ 2,456,472
Net income (loss) [1]	(976,177)	(4,385,448)	635,491	409,597	525,360
Net income (loss) per common share					
Basic [1]	(2.61)	(12.57)	1.82	1.12	1.36
Diluted [1]	(2.61)	(12.57)	1.81	1.11	1.35
Dividends declared per common share [2]	—	0.1875	0.25	—	—
Weighted average number of common shares outstanding					
Basic	373,859	348,802	348,962	366,659	385,205
Diluted	373,859	348,802	351,167	369,877	388,938
Consolidated Statements of Cash Flows data					
Cash provided by (used in)					
Operating activities	$ 219,223	$ 864,304	$ 1,222,825	$ 1,361,195	$ 1,410,891
Investing activities	(205,417)	(550,185)	(1,076,755)	(1,275,309)	(1,376,841)
Financing activities	(15,012)	(334,460)	(135,104)	(172,210)	45,768
Production (average daily)					
Oil (Bbls)	61,440	69,165	70,606	66,286	66,837
Natural gas (Mcf)	15,378	22,172	22,955	23,742	29,109
BOE (6:1)	64,003	72,861	74,432	70,243	71,689
Unit sales prices – excluding impact of derivative settlements					
Oil (per Bbl)	$ 41.12	$ 47.30	$ 90.74	$ 100.67	$ 97.18
Natural gas (per Mcf)	1.98	2.35	4.07	3.53	3.05
Unit sales prices – including impact of derivative settlements					
Oil (per Bbl)	$ 44.86	$ 67.41	$ 90.82	$ 100.64	$ 96.77
Natural gas (per Mcf)	1.98	2.83	3.99	3.53	5.67
Costs per BOE					
Lease operating expenses [3]	$ 17.71	$ 19.37	$ 23.84	$ 28.50	$ 20.29
Taxes other than income	3.33	4.13	6.25	6.87	6.10
General and administrative expenses	4.69	5.44	5.83	5.66	5.49
Depletion, depreciation, and amortization [4]	36.12	19.99	21.83	19.89	19.34
Proved oil and natural gas reserves [5]					
Oil (MBbls)	247,103	282,250	362,335	386,659	329,124
Natural gas (MMcf)	44,315	38,305	452,402	489,954	481,641
MBOE (6:1)	254,489	288,634	437,735	468,318	409,398
Proved carbon dioxide reserves					
Gulf Coast region (MMcf) [6]	5,332,576	5,501,175	5,697,642	6,070,619	6,073,175
Rocky Mountain region (MMcf) [7]	1,214,428	1,237,603	3,035,286	3,272,428	3,495,534
Consolidated Balance Sheets data [8]					
Total assets	$ 4,274,578	$ 5,885,533	$ 12,690,156	$ 11,698,406	$ 11,083,839
Total long-term liabilities	3,372,634	4,263,606	6,503,194	5,902,463	5,405,223
Stockholders' equity	468,448	1,248,912	5,703,856	5,301,406	5,114,889

(1) Includes pre-tax impairments of assets of $810.9 million and $6.2 billion for the years ended December 31, 2016 and 2015, respectively, and an accelerated depreciation charge of $591.0 million related to the Riley Ridge gas processing facility and related assets for the year ended December 31, 2016.

(2) In September 2015, in light of the continuing low oil price environment and our desire to maintain our financial strength and flexibility, the Company's Board of Directors suspended our quarterly cash dividend.

(3) Lease operating expenses reported in this table include certain special items comprised of (1) lease operating expenses and related insurance recoveries recorded to remediate an area of Delhi Field in 2014 and 2015, (2) a reimbursement for a retroactive utility rate adjustment in 2015, and (3) other insurance recoveries in 2015. If these special items are excluded, lease operating expenses would have totaled $528.8 million, $654.7 million and $616.6 million for the years ended December 31, 2015, 2014 and 2013, respectively, and lease operating expenses per BOE would have averaged $19.88, $24.10 and $24.05 for the years ended December 31, 2015, 2014 and 2013, respectively.

(4) Depletion, depreciation, and amortization during the year ended December 31, 2016 includes an accelerated depreciation charge of $591.0 million, or $25.23 per BOE, associated with the Riley Ridge gas processing facility and related assets (see Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Depletion, Depreciation, and Amortization*).

(5) Estimated proved reserves as of December 31, 2015, reflect negative reserve revisions of approximately 126 MMBOE (29%) in 2015 due to declines in the average first-day-of-the-month NYMEX oil price used to estimate reserves from $94.99 per Bbl at December 31, 2014, to $50.28 per Bbl at December 31, 2015. In addition, the average first-day-of-the-month NYMEX natural gas price used to estimate reserves declined from $4.30 per MMBtu at December 31, 2014, to $2.63 per MMBtu at December 31, 2015.

(6) 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 4.2 Tcf, 4.4 Tcf, 4.5 Tcf, 4.8 Tcf and 4.8 Tcf at December 31, 2016, 2015, 2014, 2013 and 2012, respectively, and include reserves dedicated to volumetric production payments of 12.3 Bcf, 25.3 Bcf, 9.3 Bcf, 28.9 Bcf and 57.1 Bcf at December 31, 2016, 2015, 2014, 2013 and 2012, respectively (see *Supplemental CO_2 Disclosures (Unaudited)* to the Consolidated Financial Statements).

(7) Proved CO_2 reserves in the Rocky Mountain region consist of our overriding royalty interest in LaBarge Field and our reserves at Riley Ridge (presented on a gross (8/8ths) basis), of which our net revenue interest was approximately 1.2 Tcf, 1.2 Tcf, 2.6 Tcf, 2.9 Tcf and 2.9 Tcf at December 31, 2016, 2015, 2014, 2013 and 2012, respectively. As of December 31, 2015, Riley Ridge CO_2 and helium reserves were reclassified and are no longer considered proved reserves primarily as a result of the decline in average first-day-of-the-month natural gas prices utilized in preparing our December 31, 2015 reserve report.

(8) The consolidated balance sheet data presented in this table reflect the adoption of Financial Accounting Standards Board ("FASB") Accounting Standards Update ("ASU") 2016-09, *Improvements to Employee Share-Based Payment Accounting*, ASU 2015-17, *Income Taxes*, and ASU 2015-03, *Interest – Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs*. See Note 1, *Significant Accounting Policies – Recent Accounting Pronouncements* to the consolidated financial statements for further discussion.

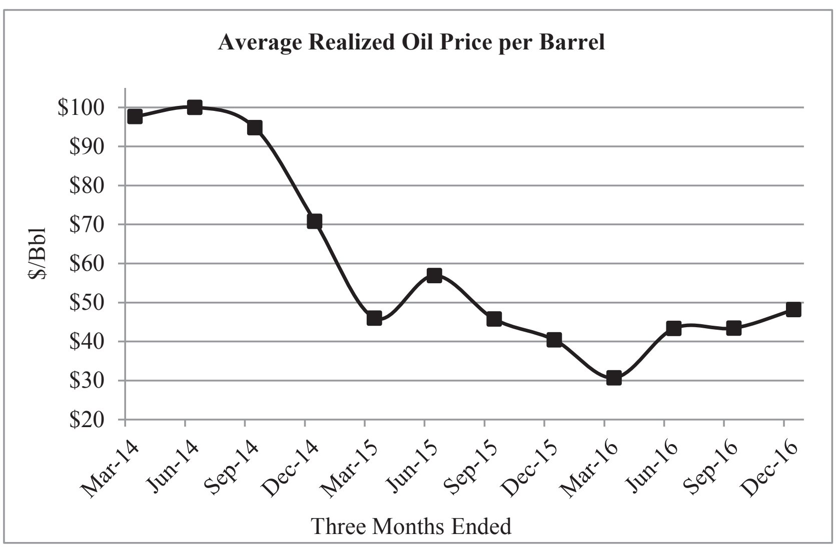
Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

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 an independent oil and natural gas company with operations focused in two key operating areas: the Gulf Coast and Rocky Mountain regions. Our goal is to increase the value of our properties through a combination of exploitation, drilling and proven engineering extraction practices, with the most significant emphasis relating to CO_2 enhanced oil recovery operations.

Oil Price Decline and Impact on Our Business. Oil prices generally constitute the single largest variable in our operating results. Oil prices have historically been volatile, with NYMEX oil prices ranging from $26 to $107 per Bbl over the last three calendar years, with prices in February 2016 representing the lowest level in over 14 years. The following chart illustrates the fluctuations in our realized oil prices, excluding the impact of commodity derivative settlements, during 2014, 2015 and 2016.



	Oil price per Bbl		
Average realized prices	2014	2015	2016
First quarter	$ 97.69	$ 46.02	$ 30.71
Second quarter	100.04	56.92	43.38
Third quarter	94.78	45.74	43.45
Fourth quarter	70.80	40.41	48.03

Although realized oil prices during the second half of 2016 increased from the lows experienced in the first quarter of 2016, our focus continues to remain on cost reductions and preserving liquidity. Cost reductions have been realized in 2016 in all categories of our business. Our 2016 capital development expenditures totaled $208.6 million, which were fully funded with cash flows from operations, thus preserving our liquidity. One advantage we have in this environment is that our oil assets have relatively low decline rates even with our significantly reduced planned capital spending level, and therefore our average daily production declined by less than 10% in 2016, excluding the impact of weather-related downtime at Conroe and Thompson fields, completed asset sales, and production shut in for economic reasons. Lastly, we have hedged a portion of our estimated oil production through 2017 in order to cover our current level of cash operating costs and to help mitigate any future price declines or sustained low oil prices (see *Results of Operations – Commodity Derivative Contracts* below). Our 2017 capital spending has been budgeted at approximately $300 million, excluding capitalized interest and acquisitions, a 44% increase over the 2016 capital spending level. It is expected that the projected cash flow from operations, based on current NYMEX futures prices in late-February 2017, will fund all but a minor amount of this capital spending. With this increased capital spending level, we currently anticipate our 2017 average daily production remaining relatively flat with our exit rate in 2016 of roughly 60,000 BOE/d.

During 2016, we have continued to evaluate our assets with a goal of increasing the value of both existing assets and future projects by optimizing field operational and development plans, reducing CO_2 injection volumes through increased efficiency, and reducing costs such as power and workovers. We have reduced our overall CO_2 injection volumes by 32% and our total lease operating expenses by $113.8 million (22%) on a normalized basis (see *Results of Operations – Production Expenses – Lease Operating Expenses*) when comparing the years ended December 31, 2016 and 2015. These initiatives aim to increase the profitability of our operations and make them more resilient to lower oil prices.

2016 Operating Highlights. Our financial results have been significantly impacted by the decrease in realized oil prices as highlighted above, which decreased from an average of $90.74 per Bbl during 2014 to $41.12 per Bbl during 2016. During 2016, we recognized a net loss of $976.2 million, compared to a net loss of $4.4 billion during 2015. Our net loss in 2016 decreased due to the substantial decrease in noncash impairments, primarily because oil prices, a significant driver of our full-cost ceiling test write-downs, stabilized and began to increase during the course of 2016, which resulted in the trailing 12-month average price (the primary driver of the value of our proved reserves and therefore any full cost pool ceiling test write-downs) flattening, rather than declining each quarter as was the case in 2015. Impairments of assets totaled $810.9 million ($508.2 million net of tax) in 2016, compared to $6.2 billion ($4.3 billion net of tax) in 2015 (see *Results of Operations – Write-Down of Oil and Natural Gas Properties* and *2015 Impairment of Goodwill* below). Additionally, the effect of the reduction in asset impairments in 2016 was partially offset by an accelerated depreciation charge of $591.0 million recorded in 2016 related to the Riley Ridge gas processing facility and related assets (see *Results of Operations – Depletion, Depreciation, and Amortization* below).

We generated $219.2 million of cash flow from operating activities during 2016, compared to $864.3 million during 2015, due primarily to a $427.5 million decline in derivative settlements and $277.3 million reduction in revenues due to the lower oil prices and less sales volumes, partially offset by reductions in operating expenses.

During 2016, our oil and natural gas production, which was 96% oil, averaged 64,003 BOE/d, compared to an average of 72,861 BOE/d produced during 2015. This 12% decrease in production was primarily due to weather-related shut-in production, production shut in due to economics, facility downtime, maintenance and repair work, and natural production declines based on our lower capital spending level. Total production in 2015 also includes production related to certain non-core assets in the Williston Basin of North Dakota and Montana (the "Williston Assets"), which were sold during the third quarter of 2016, and other property divestitures. Production related to the Williston Assets and other property divestitures averaged 1,005 BOE/d in 2016, compared to 1,993 in 2015. These production decreases were partially offset by increases in production due to continued CO_2 enhanced oil recovery response at Delhi Field in the Gulf Coast region and Bell Creek Field in the Rocky Mountain region. See *Results of Operations – Production* for further discussion.

Our average realized oil price per barrel, excluding the impact of commodity derivative contracts, was $41.12 per Bbl during 2016, a decrease of 13% compared to $47.30 per Bbl realized during 2015. The oil price we realized relative to NYMEX oil prices (our NYMEX oil price differential) was $2.29 per Bbl below NYMEX prices during 2016, a $0.74 per Bbl decline compared to realized prices of $1.55 per Bbl below NYMEX in 2015, primarily due to weakening of our Gulf Coast region LLS price differentials, offset in part by improvement in the Rocky Mountain region discount in 2016 relative to NYMEX oil prices.

One of our primary focuses in the past few years has been to reduce costs throughout the organization through a number of internal initiatives. As a result of these efforts, we have been able to achieve reductions in our lease operating expenses, with total lease operating expenses of $414.9 million during 2016, a 19% reduction when compared to 2015 levels. Excluding special or unusual amounts reported in 2015, total lease operating expenses per BOE during 2016 were $17.71, compared to $19.88 during 2015, with decreases realized in most categories of lease operating expenses. General and administrative expenses per BOE decreased 14% when comparing the year-ended December 31, 2016 to 2015, primarily due to lower employee-related costs such as salaries, bonus accruals and long-term incentives.

2016 Debt Reduction Transactions. During 2016, we completed a series of privately negotiated debt exchanges and open-market debt repurchases, contributing to a net reduction of our debt principal balance of approximately $530.4 million between December 31, 2015 and 2016. In May 2016, we exchanged $1,057.8 million of existing senior subordinated notes with a limited number of holders for $614.9 million of our new 9% Senior Secured Second Lien Notes due 2021 (the "2021 Senior Secured Notes") plus 40.7 million shares of Denbury common stock, resulting in a net reduction from these exchanges of $442.9 million in our debt principal. During 2016, we purchased $181.9 million of our existing senior subordinated notes for $76.7 million in open-market transactions, for a net reduction of $105.2 million of our debt principal. See *Capital Resources and Liquidity – 2016 Debt Reduction Transactions* for further discussion.

2016 Divestiture of Non-Core Assets. On August 31, 2016, we completed the sale of the Williston Assets for $58 million (before closing adjustments). The sale had an effective date of April 1, 2016, and proceeds realized after closing adjustments totaled $53.6 million. Approximately $9 million of proceeds from the sale of Williston Assets was paid by the purchaser directly to a qualified intermediary to facilitate a like-kind exchange, and are therefore not reflected as an investing activity in our Consolidated Statements of Cash Flows.

Grieve Field Revised Joint Venture. On August 4, 2016, the Company and its joint venture partner in Grieve Field, located in Wyoming, reached an agreement to revise the joint venture arrangement between the parties for the continued development of such field. The revised agreement provides for our partner to fund up to $55 million of the remaining estimated capital to complete development of the facility and fieldwork in exchange for a 14% higher working interest and a disproportionate sharing of revenue from the first 2 million barrels of production. As a result of this agreement, our working interest in the field was reduced from 65% to 51%. This arrangement will accelerate the remaining development of the facility and fieldwork, and we currently anticipate first tertiary production by the middle of 2018.

CAPITAL RESOURCES AND LIQUIDITY

Overview. Our primary sources of capital and liquidity are our cash flows from operations and availability of borrowing capacity under our senior secured bank credit facility. As a result of the significant reduction in oil prices discussed above and less advantageous hedge positions, our cash flow from operations has significantly decreased, from $864.3 million during 2015 to $219.2 million during 2016.

The preservation of cash and liquidity remains a significant priority for us in the current oil price environment. We have taken steps to lower our costs in all categories of our business, and we have made significant progress in that regard. Over the past year, we have also amended our senior secured bank credit facility to relax certain financial performance covenants through 2018 (see *Senior Secured Bank Credit Facility* below). As of December 31, 2016, we had $301.0 million drawn on our $1.05 billion senior secured bank credit facility, leaving us $673.7 million of current liquidity after consideration of $75.3 million of outstanding letters of credit. This liquidity, coupled with our other cost saving and liquidity preservation measures and the improvement in oil prices, should be sufficient to cover any foreseeable cash flow shortfall and fund our capital and operating cash outflows.

In order to provide a level of price protection to a portion of our oil production, we have entered into a combination of oil swaps, collars, and three-way collars through the fourth quarter of 2017 (see *Results of Operations – Commodity Derivative Contracts* below). While a portion of these derivatives entered into in early 2016 are fixed-price swaps at prices that do not support capital spending levels which would grow our production, they do at least cover our most recent total cash operating costs, which were in a per-barrel range in the mid-$30's during 2016 (including corporate overhead and interest), thereby minimizing the amount needed to be drawn under our senior secured bank credit facility for day-to-day operations.

Since we do not expect oil prices to recover in the foreseeable future to recent historical highs of 2014, we must adjust our business to compete in an oil price environment that is likely not as robust as it was a few years ago, requiring reductions in overall debt levels over time. We made significant progress in this endeavor during 2016 with a net reduction in our debt principal of $530.4 million (see Note 4, *Long-Term Debt*, to the Consolidated Financial Statements). Our subordinated debt is currently trading significantly higher than it was during the first half of 2016, making it more difficult to make accretive exchanges or repurchases of this debt. We would like to reduce our debt further if possible, and we plan to monitor the market and be opportunistic in our debt transactions based upon market conditions. These potential transactions could include purchases of our subordinated debt in the open market, cash tenders for our debt or public or privately negotiated debt exchanges, and future potential debt reduction with proceeds of issuances of equity, asset sales and other cash-generating activities. We may utilize a portion of the availability under our senior secured bank credit facility for such repurchases and may also consider other forms of capital such as additional second lien notes or other senior notes.

Senior Secured Bank Credit Facility. In December 2014, we entered into an Amended and Restated Credit Agreement with JPMorgan Chase Bank, N.A., as administrative agent, and other lenders party thereto (the "Bank Credit Agreement"). In October 2016, as part of our semiannual borrowing base redetermination, the borrowing base and lender commitments for our Bank Credit Agreement were reaffirmed at $1.05 billion, with our next borrowing base redetermination scheduled for May 2017. As of December 31, 2016, we had $301.0 million of debt outstanding and $75.3 million in letters of credit under the Bank Credit Agreement. In order to provide more flexibility in managing our balance sheet, the credit extended by our lenders, and continuing compliance with financial performance covenants in this low oil price environment, we entered into three amendments to the Bank Credit Agreement between May 2015 and April 2016 making the following modifications to the Bank Credit Agreement:

- for 2016 and 2017, the maximum permitted ratio of consolidated total net debt to consolidated EBITDAX covenant was suspended and replaced by a maximum permitted ratio of consolidated senior secured debt to consolidated EBITDAX covenant of 3.0 to 1.0 (only debt under our Bank Credit Agreement is considered consolidated senior secured debt for purposes of this ratio);
- for 2016 and 2017, a new covenant was added to require a minimum permitted ratio of consolidated EBITDAX to consolidated interest charges of 1.25 to 1.0;
- allowing for the incurrence of up to $1.0 billion of junior lien debt (subject to customary requirements), with $385.1 million of future incurrence available as of December 31, 2016;
- limiting unrestricted cash and cash equivalents to $225 million if more than $250 million of borrowings are outstanding under the Bank Credit Agreement; and
- limiting the amount spent on repurchases or other redemptions of our senior subordinated notes to $225 million, with up to $148.3 million of this capacity remaining available as of December 31, 2016.

Additionally, we are required to maintain a current ratio, as determined under the Bank Credit Agreement, of not less than 1.0 to 1.0.

Beginning in the first quarter of 2018, the ratio of consolidated total net debt to consolidated EBITDAX covenant will be reinstated, utilizing an annualized EBITDAX amount for the first, second, and third quarters of 2018 and building to a trailing four quarters by the end of 2018, with the maximum permitted ratios being 6.0 to 1.0 for the first quarter ending March 31, 2018, 5.5 to 1.0 for the second quarter ending June 30, 2018, and 5.0 to 1.0 for the third and fourth quarters ending September 30 and December 31, 2018, and returning to 4.25 to 1.0 for the first quarter ending March 31, 2019.

Under these financial performance covenant calculations, as of December 31, 2016, our ratio of consolidated senior secured debt to consolidated EBITDAX was 0.72 to 1.0 (based upon a maximum permitted ratio of 3.0 to 1.0), our ratio of consolidated EBITDAX to consolidated interest charges was 2.46 to 1.0 (based upon a required ratio of not less than 1.25 to 1.0), and our current ratio was 3.04 to 1.0 (based upon a required ratio of not less than 1.0 to 1.0). Based upon our currently forecasted levels of production and costs, hedges in place as of February 22, 2017, and current oil commodity futures prices, we currently anticipate continuing to be in compliance with our financial performance covenants during 2017.

The above description of our Bank Credit Agreement financial performance covenants and the changes provided for within the three amendments are qualified by the express language and defined terms contained in the Bank Credit Agreement, the First Amendment to the Bank Credit Agreement dated May 4, 2015, the Second Amendment to the Bank Credit Agreement dated February 17, 2016, and the Third Amendment to the Bank Credit Agreement dated April 18, 2016, each of which are filed as exhibits to our periodic reports filed with the SEC.

2016 Debt Reduction Transactions. During 2016, we completed a series of privately negotiated debt exchanges and open-market debt repurchases, contributing to a net reduction of our debt principal balance of $530.4 million between December 31, 2015 and 2016. In May 2016, we entered into privately negotiated agreements to exchange $175.1 million principal amount of our 6⅜% Senior Subordinated Notes due 2021 ("2021 Notes"), $411.0 million principal amount of our 5½% Senior Subordinated Notes due 2022 ("2022 Notes"), and $471.7 million principal amount of our 4⅝% Senior Subordinated Notes due 2023 ("2023 Notes") for $614.9 million principal amount of new 2021 Senior Secured Notes plus 40.7 million shares of Denbury common stock, resulting in a net reduction from these exchanges of $442.9 million in our debt principal. Our Bank Credit Agreement allows for the incurrence of up to $1.0 billion of junior lien debt, so after taking these exchanges into account, we have an additional $385.1 million of junior lien debt capacity that remains available to us.

During 2016, we repurchased a total of $181.9 million principal amount of our existing senior subordinated notes in open-market transactions, consisting of $9.8 million principal amount of our 2021 Notes, $66.1 million principal amount of our 2022 Notes, and $106.0 million principal amount of our 2023 Notes for a total purchase price of $76.7 million, excluding accrued interest. The repurchases were made at prices ranging from approximately 25% to 75% of the principal amount of the individual senior subordinated notes. In connection with these series of transactions, during 2016 we recognized a $103.1 million gain on debt extinguishment, net of unamortized debt issuance costs written off. We currently estimate combined annual cash interest savings of approximately $7 million related to these repurchases and the exchange transactions. Our Bank Credit Agreement limits open-market repurchases of our senior subordinated notes to $225 million, and as of February 22, 2017, we have up to $148.3 million of remaining capacity for senior subordinated notes repurchases or other redemptions.

2017 Capital Spending. We currently anticipate that our full-year 2017 capital budget, excluding capitalized interest and acquisitions, will be approximately $300 million, an increase of 44% over 2016 spending levels, which includes approximately $55 million in capitalized internal acquisition, exploration and development costs and pre-production tertiary startup costs. This combined 2017 capital budget amount, excluding capitalized interest and acquisitions, compares to combined 2016 development capital spending of $208.6 million (see *Capital Expenditure Summary* below for a summary of actual 2016 expenditures). The 2017 capital budget, excluding capitalized interest and acquisitions, is comprised of the following:

- $175 million allocated for tertiary oil field expenditures;
- $60 million allocated for other areas, primarily non-tertiary oil field expenditures;
- $10 million to be spent on CO_2 sources and pipelines; and
- $55 million for other capital items such as capitalized internal acquisition, exploration and development costs and pre-production tertiary startup costs.

Based upon our currently forecasted levels of production and costs, commodity hedges in place, and current oil commodity futures prices, we intend to fund our development capital spending primarily with cash flow from operations, with any potential shortfall funded with incremental borrowings under our Bank Credit Agreement, under which as of December 31, 2016, we had ample available borrowing capacity to cover any foreseeable cash flow shortfall. If prices were to decrease or changes in operating results were to cause a reduction in anticipated 2017 cash flows significantly below our currently forecasted operating cash flows, we would likely reduce our capital expenditures. If we reduce our capital spending due to lower cash flows, any sizeable reduction would likely lower our anticipated production levels in future years.

Capital Expenditure Summary. The following table reflects incurred capital expenditures (including accrued capital) for the years ended December 31, 2016, 2015 and 2014:

	Year Ended December 31,		
In thousands	2016	2015	2014
Capital expenditures by project			
Tertiary oil fields	$ 119,117	$ 199,923	$ 629,790
Non-tertiary fields	31,034	101,667	240,187
Capitalized internal costs (1)	56,260	66,308	67,908
Oil and natural gas capital expenditures	206,411	367,898	937,885
CO_2 pipelines	34	14,444	45,672
CO_2 sources	2,171	23,643	56,460
Other	30	1,177	1,853
Capital expenditures, before acquisitions and capitalized interest	208,646	407,162	1,041,870
Acquisitions of oil and natural gas properties	11,706	25,765	8,773
Capital expenditures, before capitalized interest	220,352	432,927	1,050,643
Capitalized interest	25,982	32,146	24,202
Capital expenditures, total	$ 246,334	$ 465,073	$ 1,074,845

(1) Includes capitalized internal acquisition, exploration and development costs and pre-production tertiary startup costs.

Our 2016 capital expenditures and property acquisitions were fully funded with $219.2 million of cash flows from operations, plus additional funds provided by asset sales and borrowings on our senior secured bank credit facility. Our 2015 and 2014 capital expenditures and property acquisitions were fully funded with cash flows from operations of $864.3 million and $1.2 billion, respectively.

Commitments and Obligations. A summary of our obligations at December 31, 2016, is presented in the following table:

	Payments Due by Period				
In thousands	2017	2018 and 2019	2020 and 2021	Thereafter	Total
Contractual obligations					
Bank Credit Agreement	$ —	$ 301,000	$ —	$ —	$ 301,000
Estimated interest payments on senior secured bank credit facility, senior secured second lien notes, and subordinated debt	152,905	304,764	240,967	58,541	757,177
Senior secured debt (principal balance)	—	—	614,919	—	614,919
Subordinated debt (principal balance)	2,250	—	215,144	1,395,209	1,612,603
Operating lease obligations	10,965	21,728	19,730	38,549	90,972
Pipeline and capital lease obligations	48,579	88,354	53,964	165,170	356,067
Other obligations (1)	106,838	226,296	220,362	733,565	1,287,061
Commodity derivative liabilities (2)	69,279	—	—	—	69,279
Asset retirement obligations (3)	1,807	6,857	13,506	760,309	782,479
Total contractual obligations	$ 392,623	$ 948,999	$ 1,378,592	$ 3,151,343	$ 5,871,557

(1) Represents future cash commitments under contracts in place as of December 31, 2016, primarily for purchase contracts for CO_2 captured from industrial sources, 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 *2017 Capital Spending* above). 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. For further discussion of our long-term commitments to purchase CO_2, see Note 10, *Commitments and Contingencies*, to the Consolidated Financial Statements.

(2) Commodity derivative liabilities represent the fair value of our commodity derivatives presented as liabilities in our Consolidated Balance Sheets as of December 31, 2016. 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 8, *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 $149.1 million, as determined under the *Asset Retirement and Environmental Obligations* topic of the Financial Accounting Standards Board Codification ("FASC"), and is further discussed in Note 2, *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, 2016, we had a total of $75.3 million of letters of credit outstanding under our senior secured bank credit facility. Additionally, we have obligations for development and exploratory expenditures that arise from our normal capital expenditure program or from other transactions common to our industry, none of which are recorded on our balance sheet. 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, which are only included in the table above to the extent we have firm contracts. For a further discussion of our future development costs, see *Supplemental Oil and Natural Gas Disclosures (Unaudited)* to the Consolidated Financial Statements.

In the second quarter of 2016, we amended our CO_2 offtake agreement with Mississippi Power Company ("MSPC"), which amendment included increasing our offtake percentage from 70% to 100% of CO_2 quantities produced and lowering the base price related to the cost of CO_2, deliveries of which are currently expected to begin during the first half of 2017. Based on the amended terms in the agreement, we concluded for accounting purposes that the agreement contains an embedded lease related to the pipeline owned by MSPC used to transport CO_2 to Denbury. We currently plan to record a capital lease on the balance sheet of approximately $110 million upon lease commencement.

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 return metrics, with relatively low risk, assuming crude oil prices are at levels that support the development of those projects. We have been developing tertiary oil properties for over 17 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 competitive with 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 changes are made thereafter.

Production Rates. The production 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. With the recently low oil prices, our pace of development has generally slowed, thereby leading to a less consistent growth pattern. We find all of these fluctuations to be normal, and generally expect oil production at a tertiary field to increase over time until the field is fully 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 over 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.

	Year Ended December 31,		
In thousands, except per share and unit data	2016	2015	2014
Operating results			
Net income (loss) (1)	$ (976,177)	$ (4,385,448)	$ 635,491
Net income (loss) per common share – basic (1)	(2.61)	(12.57)	1.82
Net income (loss) per common share – diluted (1)	(2.61)	(12.57)	1.81
Dividends declared per common share (2)	—	0.1875	0.25
Net cash provided by operating activities	219,223	864,304	1,222,825
Average daily production volumes			
Bbls/d	61,440	69,165	70,606
Mcf/d	15,378	22,172	22,955
BOE/d	64,003	72,861	74,432
Operating revenues			
Oil sales	$ 924,618	$ 1,194,038	$ 2,338,367
Natural gas sales	11,133	18,988	34,106
Total oil and natural gas sales	$ 935,751	$ 1,213,026	$ 2,372,473
Commodity derivative contracts (3)			
Receipt on settlements of commodity derivatives	$ 84,181	$ 511,699	$ 1,421
Noncash fair value gains (losses) on commodity derivatives (4)	(212,125)	(363,700)	553,834
Commodity derivatives income (expense)	$ (127,944)	$ 147,999	$ 555,255
Unit prices – excluding impact of derivative settlements			
Oil price per Bbl	$ 41.12	$ 47.30	$ 90.74
Natural gas price per Mcf	1.98	2.35	4.07
Unit prices – including impact of derivative settlements (3)			
Oil price per Bbl	$ 44.86	$ 67.41	$ 90.82
Natural gas price per Mcf	1.98	2.83	3.99
Oil and natural gas operating expenses			
Lease operating expenses	$ 414,937	$ 515,043	$ 647,559
Marketing expenses, net of third-party purchases, and plant operating expenses	45,151	48,319	47,965
Production and ad valorem taxes	68,878	95,687	155,495
Oil and natural gas operating revenues and expenses per BOE			
Oil and natural gas revenues	$ 39.95	$ 45.61	$ 87.33
Lease operating expenses	17.71	19.37	23.84
Marketing expenses, net of third-party purchases, and plant operating expenses	1.92	1.82	1.76
Production and ad valorem taxes	2.94	3.60	5.72
CO_2 sources – revenues and expenses			
CO_2 sales and transportation fees	$ 24,816	$ 30,626	$ 44,643
CO_2 discovery and operating expenses	(3,374)	(4,557)	(25,222)
CO_2 revenue and expenses, net	$ 21,442	$ 26,069	$ 19,421

(1) Includes pre-tax full-cost pool ceiling test write-downs of our oil and natural gas properties of $810.9 million and $4.9 billion for the years ended December 31, 2016 and 2015, respectively, an impairment of goodwill of $1.3 billion for the year ended December 31, 2015, and an accelerated depreciation charge of $591.0 million for the year ended December 31, 2016 related to the Riley Ridge gas processing facility and related assets.

(2) In September 2015, in light of the continuing low oil price environment and our desire to maintain our financial strength and flexibility, the Company's Board of Directors suspended our quarterly cash dividend.

(3) See also *Commodity Derivative Contracts* below and *Market Risk Management* for information concerning our commodity derivative transactions.

(4) Noncash fair value gains (losses) 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 gains (losses) on commodity derivatives represent only the net changes between periods of the fair market values of commodity derivative positions, and exclude the impact of settlements on commodity derivatives during the period, which were receipts on settlements of $84.2 million, $511.7 million and $1.4 million for the years ended December 31, 2016, 2015 and 2014, respectively. We believe that noncash fair value gains (losses) on commodity derivatives is a useful supplemental disclosure to "Commodity derivatives expense (income)" in order to differentiate noncash fair market value adjustments from receipts or payments upon 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 (loss) to present those measures on a comparative basis across companies, as well as to assess compliance with certain debt covenants. Noncash fair value gains (losses) 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 gains (losses) on commodity derivatives.

Production

Average daily production by area for 2016, 2015 and 2014, and for each of the quarters of 2016, is shown below:

	Average Daily Production (BOE/d)						
	2016 Quarters				Year Ended December 31,		
Operating Area	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	2016	2015	2014
Tertiary oil production							
Gulf Coast region							
Mature properties (1)	9,666	9,415	8,653	8,440	9,040	10,830	11,817
Delhi	3,971	3,996	4,262	4,387	4,155	3,688	4,340
Hastings	5,068	4,972	4,729	4,552	4,829	5,061	4,777
Heidelberg	5,346	5,246	5,000	4,924	5,128	5,785	5,707
Oyster Bayou	5,494	5,088	4,767	4,988	5,083	5,898	4,683
Tinsley	7,899	7,335	6,756	6,786	7,192	8,119	8,507
Total Gulf Coast region	37,444	36,052	34,167	34,077	35,427	39,381	39,831
Rocky Mountain region							
Bell Creek	3,020	3,160	3,032	3,269	3,121	2,221	1,248
Total Rocky Mountain region	3,020	3,160	3,032	3,269	3,121	2,221	1,248
Total tertiary oil production	40,464	39,212	37,199	37,346	38,548	41,602	41,079
Non-tertiary oil and gas production							
Gulf Coast region							
Mississippi	673	1,017	963	745	850	1,194	1,787
Texas	6,148	4,104	4,234	5,143	4,906	6,443	6,290
Other	549	456	538	569	528	889	1,061
Total Gulf Coast region	7,370	5,577	5,735	6,457	6,284	8,526	9,138
Rocky Mountain region							
Cedar Creek Anticline	17,778	16,325	16,017	15,186	16,322	17,997	18,834
Other	2,070	1,862	1,763	1,696	1,844	2,743	3,106
Total Rocky Mountain region	19,848	18,187	17,780	16,882	18,166	20,740	21,940
Total non-tertiary production	27,218	23,764	23,515	23,339	24,450	29,266	31,078
Total continuing production	67,682	62,976	60,714	60,685	62,998	70,868	72,157
Property sales							
Williston Assets (2)	1,364	1,267	819	—	864	1,549	1,744
Other property divestitures	305	263	—	—	141	444	531
Total production	69,351	64,506	61,533	60,685	64,003	72,861	74,432

(1) Mature properties include Brookhaven, Cranfield, Eucutta, Little Creek, Lockhart Crossing, Mallalieu, Martinville, McComb and Soso fields.

(2) Includes non-tertiary production in the Rocky Mountain region related to the sale of remaining non-core assets in the Williston Basin of North Dakota and Montana, which closed in the third quarter of 2016.

Total Production

Total continuing production during 2016 averaged 62,998 BOE/d, including 38,548 Bbls/d from tertiary properties and 24,450 BOE/d from non-tertiary properties. Total continuing production excludes production from the Williston Assets that were sold during the third quarter of 2016 and other minor property divestitures, which production totaled 1,005 BOE/d during 2016, compared to 1,993 BOE/d and 2,275 BOE/d produced from these properties during 2015 and 2014, respectively. Our 2016 total continuing production level represents a decrease of 7,870 BOE/d (11%) compared to 2015 levels. Approximately one-third of these 2016 production declines were attributable to production shut-in due to economics and weather-related shut-in production at Thompson and Conroe fields. The remaining decline is largely due to natural production declines; although we have some inclining production at our fields, we did not invest sufficient capital during 2016 to hold production flat.

As of December 31, 2016, we estimate that approximately 1,900 BOE/d of production remained shut in attributable to uneconomic wells, compared to approximately 1,650 BOE/d of production shut in as of December 31, 2015. The increase during 2016 was largely attributable to the impact of oil price declines in early 2016, partially offset by volumes sold in connection with the Williston Asset sale, in addition to minor volumes returned to production during the second half of 2016. Our production during 2016 was 96% oil, consistent with oil production of 95% during 2015 and 2014. We currently anticipate 2017 average daily production will remain relatively flat with our exit rate in 2016 of roughly 60,000 BOE/d.

Tertiary Production

Oil production from our tertiary operations averaged 38,548 Bbls/d during 2016, a decrease of 3,054 Bbls/d (7%) from our 2015 tertiary production level of 41,602 Bbls/d. These declines were primarily due to planned facility downtime at Tinsley Field and natural production declines at our mature fields in the Gulf Coast region, partially offset by increased production due to continued CO_2 enhanced oil recovery response at Delhi and Bell Creek fields. Production from Tinsley and Oyster Bayou fields are believed to have peaked and therefore are expected to generally decline in the future.

Non-Tertiary Production

Continuing production from our non-tertiary operations averaged 24,450 BOE/d during 2016, a decrease of 4,816 BOE/d (16%) compared to 2015 levels. These production declines include weather-related downtime at Thompson and Conroe fields, as noted above, and production attributable to wells shut in as uneconomic to either produce or repair due to commodity prices. When combined, these weather-related downtime and shut-in production impacts resulted in a production decline of approximately 2,500 BOE/d when compared to 2015. In addition, the changes include natural production declines at our non-tertiary properties in the Rocky Mountain and Gulf Coast regions.

Oil and Natural Gas Revenues

Oil and natural gas revenues decreased 23% between 2015 and 2016 and decreased 49% between 2014 and 2015. The changes in our oil and natural gas revenues are due to changes in production quantities and commodity prices (excluding any impact of our commodity derivative contracts), as reflected in the following table:

	Year Ended December 31, 2016 vs. 2015		Year Ended December 31, 2015 vs. 2014	
In thousands	Decrease in Revenues	Percentage Decrease in Revenues	Decrease in Revenues	Percentage Decrease in Revenues
Change in oil and natural gas revenues due to:				
Decrease in production	$ (144,548)	(12)%	$ (50,093)	(2)%
Decrease in commodity prices	(132,727)	(11)%	(1,109,354)	(47)%
Total decrease in oil and natural gas revenues	$ (277,275)	(23)%	$ (1,159,447)	(49)%

Excluding any impact of our commodity derivative contracts, our average net realized commodity prices and NYMEX differentials were as follows during 2016, 2015 and 2014:

	Year Ended December 31,		
	2016	2015	2014
Average net realized prices			
Oil price per Bbl	$ 41.12	$ 47.30	$ 90.74
Natural gas price per Mcf	1.98	2.35	4.07
Price per BOE	39.95	45.61	87.33
Average NYMEX differentials			
Oil per Bbl	$ (2.29)	$ (1.55)	$ (2.21)
Natural gas per Mcf	(0.58)	(0.28)	(0.20)

As reflected in the table above, our average net realized oil price, excluding the impact of commodity derivative contracts, decreased 13% during 2016 from the average price received during 2015. Company-wide average oil price differentials were $2.29 per Bbl below NYMEX in 2016, compared to an average differential of $1.55 per Bbl below NYMEX in 2015 and $2.21 per Bbl below NYMEX in 2014. The decline in our average oil price differentials between 2015 and 2016 was principally due to weakening of our Gulf Coast region LLS price differentials, offset in part by Rocky Mountain region price differentials described below. 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, crude oil quality, and location differentials. The oil differentials we received in the Gulf Coast and Rocky Mountain regions are discussed in further detail below.

Our average NYMEX oil differential in the Gulf Coast region was a negative $1.42 per Bbl during 2016, compared to a positive $0.49 per Bbl and $1.73 per Bbl during 2015 and 2014, respectively. These differentials are impacted significantly by the changes in prices received for our crude oil sold under LLS index prices relative to the change in NYMEX prices, as well as various other price adjustments such as those noted above. The quarterly average LLS-to-NYMEX differential (on a trade-month basis) averaged a positive $1.70 per Bbl, $3.72 per Bbl and $3.88 per Bbl during 2016, 2015 and 2014, respectively. During 2016, we sold approximately 60% of our crude oil at prices based on, or 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.

NYMEX oil differentials in the Rocky Mountain region averaged $3.97 per Bbl below NYMEX during 2016, compared to an average differential of $5.60 per Bbl below NYMEX in 2015 and $10.19 per Bbl below NYMEX in 2014. Differentials in the Rocky Mountain region can fluctuate significantly on a month-to-month basis due to weather, refinery or transportation issues, and Canadian and U.S. crude oil price index volatility.

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 and to provide more certainty to our future cash flows. These contracts have historically consisted of price floors, collars, three-way collars, fixed-price swaps, and fixed-price swaps enhanced with a sold put.

The following table summarizes the impact our commodity derivative contracts had on our operating results for 2016, 2015 and 2014:

	Three Months Ended				
In thousands	March 31	June 30	September 30	December 31	Full Year
2016					
Receipt (payment) on settlements of commodity derivatives	$ 72,227	$ 52,026	$ (7,295)	$ (32,777)	$ 84,181
Noncash fair value gains (losses) on commodity derivatives (1)	(95,053)	(150,235)	28,519	4,644	(212,125)
Commodity derivatives income (expense)	$ (22,826)	$ (98,209)	$ 21,224	$ (28,133)	$ (127,944)
2015					
Receipt on settlements of commodity derivatives	$ 148,465	$ 124,151	$ 160,677	$ 78,406	$ 511,699
Noncash fair value losses on commodity derivatives (1)	(65,389)	(173,077)	(68,649)	(56,585)	(363,700)
Commodity derivatives income (expense)	$ 83,076	$ (48,926)	$ 92,028	$ 21,821	$ 147,999
2014					
Receipt (payment) on settlements of commodity derivatives	$ (27,169)	$ (50,172)	$ (24,914)	$ 103,676	$ 1,421
Noncash fair value gains (losses) on commodity derivatives (1)	(49,500)	(124,599)	277,179	450,754	553,834
Commodity derivatives income (expense)	$ (76,669)	$ (174,771)	$ 252,265	$ 554,430	$ 555,255

(1) Noncash fair value gains (losses) on commodity derivatives is a non-GAAP measure. See *Operating Results Table* above for a discussion of the reconciliation between noncash fair value gains (losses) on commodity derivatives to "Commodity derivatives expense (income)" in the Consolidated Statements of Operations. See also the *Glossary and Selected Abbreviations* for the definition of noncash fair value gains (losses) on commodity derivatives.

In order to provide a level of price protection to a portion of our oil production, we have entered into a combination of oil swaps, collars, and three-way collars through the fourth quarter of 2017. See Note 8, *Commodity Derivative Contracts*, to the Consolidated Financial Statements for additional details of our outstanding commodity derivative contracts as of December 31, 2016, and *Market Risk Management* below for additional discussion. In addition, the following table summarizes our oil derivative contracts as of February 22, 2017:

		1Q17	2Q17	3Q17	4Q17
WTI NYMEX	Volumes Hedged (Bbls/d)	22,000	22,000	—	—
Fixed-Price Swaps	Swap Price (1)	$42.67	$43.99	—	—
Argus LLS	Volumes Hedged (Bbls/d)	10,000	7,000	—	—
Fixed-Price Swaps	Swap Price (1)	$43.77	$45.35	—	—
WTI NYMEX	Volumes Hedged (Bbls/d)	4,000	—	—	1,000
Collars	Floor / Ceiling Price (1)	$40 / $54.80	—	—	$40 / $70.00
WTI NYMEX	Volumes Hedged (Bbls/d)	—	—	14,500	11,000
3-Way Collars	Sold Put Price / Floor / Ceiling Price (1)(2)	—	—	$30 / $40 / $69.09	$30 / $40 / $69.67
Argus LLS	Volumes Hedged (Bbls/d)	3,000	—	—	—
Collars	Floor / Ceiling Price (1)	$40 / $57.23	—	—	—
Argus LLS	Volumes Hedged (Bbls/d)	—	—	2,000	1,000
3-Way Collars	Sold Put Price / Floor / Ceiling Price (1)(2)	—	—	$31 / $41 / $69.25	$31 / $41 / $70.25
	Total Volumes Hedged (Bbls/d)	39,000	29,000	16,500	13,000

(1) Averages are volume weighted.

(2) If oil prices were to average less than the sold put price, receipts on settlement would be limited to the difference between the floor price and the sold put price.

Based on current futures prices as of February 22, 2017, which average approximately $54 per Bbl for the first half of 2017, and the fixed-price swaps that we have in place, we currently expect that we would make cash payments of approximately $58 million during the first half of 2017 upon settlement of these contracts, the amount of which is dependent upon fluctuations in future NYMEX oil prices in relation to the fixed prices of these swaps, which have a weighted average price of $43.63 per Bbl. Commodity derivative contracts in place covering the second half of 2017 solely include collars and three-way collars. Based on current contracts in place and NYMEX oil futures prices as of February 22, 2017, minimal settlements are currently expected during the second half of 2017. Changes in commodity prices, expiration of contracts, and new commodity contracts entered into cause fluctuations in the estimated fair value of our oil 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.

Production Expenses

Lease Operating Expenses

	Year Ended December 31,		
In thousands, except per-BOE data	2016	2015	2014
Lease operating expenses			
Tertiary	$ 252,546	$ 315,422	$ 385,080
Non-tertiary	162,391	213,336	269,613
Total normalized lease operating expenses	414,937	528,758	654,693
Tertiary – special or unusual items (1)	—	(13,715)	(7,134)
Total lease operating expenses	$ 414,937	$ 515,043	$ 647,559
Lease operating expenses per BOE			
Tertiary	$ 17.90	$ 20.77	$ 25.68
Non-tertiary	17.43	18.70	22.15
Total normalized lease operating expenses per BOE	17.71	19.88	24.10
Tertiary – special or unusual items (1)	—	(0.90)	(0.47)
Total lease operating expenses per BOE	17.71	19.37	23.84

(1) Tertiary lease operating expenses during 2015 included special items related to insurance and other reimbursements, and during 2014 included special items consisting of lease operating expenses and related insurance recoveries to remediate an area of Delhi Field.

Our lease operating costs have declined significantly as a result of our cost reduction efforts, as well as general market decreases in the prices of many of the components of these costs. The reduction was due to cost decreases in most categories of lease operating expenses, the most significant of which included (1) a decrease in workover costs and repairs as a result of reduced failures through root-cause analysis and fewer well repairs in 2016 as more wells were uneconomic to repair based on low commodity prices, (2) lower CO_2 expense resulting from a 32% decrease in CO_2 injection volumes, (3) lower power costs due to lower usage, and (4) lower company labor costs resulting from a reduction in force. On a per-BOE basis, our total lease operating expenses during 2016 decreased from 2015 levels; however, the decrease on a percentage basis was not as large as the absolute-dollar decrease, as our lower production between the periods offset some of the cost reductions.

Currently, our CO_2 expense comprises approximately 20% of our typical tertiary lease operating expenses, and for the CO_2 reserves we already own, consists of 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 industrial sources. During the year ended December 31, 2016, approximately 57% of the CO_2 utilized in our CO_2 floods consisted of CO_2 owned and produced by us (our net revenue interest). 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 during 2016 was approximately $0.38 per Mcf, including taxes paid on CO_2 production but excluding depletion, depreciation and amortization of capital expended at our CO_2 source fields and industrial sources. This per-Mcf CO_2 cost during 2016 was slightly higher than the $0.35 per Mcf comparable measure during 2015 due primarily to a lower utilization of CO_2, while certain pipeline and processing costs are relatively fixed, partially offset by higher utilization of industrial-source CO_2, which has a higher average cost than our naturally-occurring CO_2 sources.

Marketing and Plant Operating Expenses

Marketing and plant operating expenses primarily consist of amounts incurred related to the marketing, processing, and transportation of oil and natural gas production, and to a lesser extent expenses related to our Riley Ridge gas processing facility. Marketing and plant operating expenses were $57.5 million, $55.7 million and $64.4 million during 2016, 2015 and 2014, respectively.

Taxes Other than Income

Taxes other than income includes production, ad valorem and franchise taxes. Taxes other than income decreased $32.1 million (29%) between 2015 and 2016, due primarily to a decrease in production taxes resulting from lower oil and natural gas revenues and a decrease in the assessed value of our properties resulting in lower ad valorem taxes.

General and Administrative Expenses ("G&A")

	Year Ended December 31,		
In thousands, except per-BOE data and employees	2016	2015	2014
Gross cash compensation and administrative costs	$ 271,049	$ 328,802	$ 352,651
Gross stock-based compensation	21,042	39,285	39,532
Operator labor and overhead recovery charges	(133,727)	(161,182)	(171,661)
Capitalized exploration and development costs	(48,438)	(62,341)	(62,179)
Net G&A expense	$ 109,926	$ 144,564	$ 158,343
G&A per BOE			
Net administrative costs	$ 4.08	$ 4.39	$ 4.81
Net stock-based compensation	0.61	1.05	1.02
Net G&A expense	$ 4.69	$ 5.44	$ 5.83
Employees as of December 31	1,058	1,356	1,523

Gross cash compensation and administrative costs on an absolute-dollar basis decreased $57.8 million (18%) between 2015 and 2016, primarily due to lower employee-related costs such as salaries, bonus accruals and long-term incentives. As part of our efforts to reduce overhead and operating costs in response to the significant decline in oil prices, we reduced our employee headcount in mid-2015 and further reduced our employee headcount in February 2016 through involuntary workforce reductions, which contributed to an overall headcount reduction of approximately 31% between December 31, 2014 and December 31, 2016. The severance-related payments associated with the 2016 workforce reduction were approximately $9.3 million.

Net G&A expense on a per-BOE basis decreased 14% between 2015 and 2016. This decrease was primarily based upon the changes noted in gross cash compensation and administrative costs, partially offset by lower operator labor and overhead recovery charges and lower production volumes and lower capitalized exploration and development costs.

Gross stock-based compensation on an absolute-dollar basis decreased $18.2 million (46%) during 2016 compared to 2015 due to the reduction in headcount mentioned above, the reduction in stock compensation expense associated with our performance share awards for our executive officers which vested in 2016 or are projected to vest in future periods being below target levels, and the postponement of our customary annual long-term incentive award grants from January in prior years to early July in 2016, resulting in six months of expense for those grants rather than twelve.

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 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.

Interest and Financing Expenses

	Year Ended December 31,		
In thousands, except per-BOE data and interest rates	2016	2015	2014
Cash interest (1)	$ 170,772	$ 182,293	$ 193,729
Less: interest on 2021 Senior Secured Notes not reflected as interest for financial reporting purposes (1)	(32,120)	—	—
Noncash interest expense	12,475	9,121	13,476
Less: capitalized interest	(25,982)	(32,146)	(24,202)
Interest expense, net	$ 125,145	$ 159,268	$ 183,003
Interest expense, net per BOE	$ 5.34	$ 5.99	$ 6.74
Average debt principal outstanding	$ 2,973,823	$ 3,481,192	$ 3,597,646
Average interest rate (2)	5.7%	5.2%	5.4%

(1) Cash interest is presented on an accrual basis, and includes the portion of interest on our new 2021 Senior Secured Notes (interest on which is to be paid semiannually May 15 and November 15 of each year) versus the GAAP financial statement presentation in which interest on these notes is accounted for as debt and not reflected as interest for financial reporting purposes. See below for further discussion.

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

As reflected in the table above, cash interest during 2016 decreased when compared to 2015 due primarily to repurchasing a total of $181.9 million principal amount of our existing senior subordinated notes at a discount to par value in open-market transactions during 2016. In addition, we entered into privately negotiated transactions during the second quarter of 2016 to exchange $1,057.8 million principal amount of our senior subordinated notes for $614.9 million principal amount of our new 2021 Senior Secured Notes plus 40.7 million shares of Denbury common stock (see *Capital Resources and Liquidity – 2016 Debt Reduction Transactions*). Although these exchange transactions had minimal impact on our cash interest, as more fully described in Note 4, *Long-Term Debt*, to the Consolidated Financial Statements, the exchange transactions were accounted for in accordance with Financial Accounting Standards Board Codification 470-60, Troubled Debt Restructuring by Debtors, whereby $254.7 million of future interest on the 2021 Senior Secured Notes was recorded as debt as of the transaction date, which will be reduced as semiannual interest payments are made, with the remaining $22.8 million of future interest to be recognized as interest expense over the term of the 2021 Senior Secured Notes. Therefore, interest expense reflected in our Consolidated Statements of Operations on the 2021 Senior Secured Notes will be significantly lower than the actual cash interest payment. For 2016, $32.1 million of interest on the 2021 Senior Secured Notes was accounted for as debt, and is therefore not reflected as interest expense in the Consolidated Statements of Operations. During 2017, we currently expect approximately $50 million of interest on the 2021 Senior Secured Notes to be accounted for as debt, and will therefore not be reflected as interest expense in the Consolidated Statements of Operations.

Noncash interest expense during 2016 increased when compared to prior year due to the $5.5 million write-off of debt issuance costs associated with our senior secured bank credit facility following the May 2016 redetermination which reduced our borrowing base and lender commitments and the February 2016 amendment which reduced our lender commitments. Capitalized interest decreased $6.2 million (19%) during 2016, primarily due to a reduction in the number of projects that qualify for interest capitalization.

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

	Year Ended December 31,		
In thousands, except per-BOE data	2016	2015	2014
Oil and natural gas properties	$ 149,700	$ 412,989	$ 469,596
CO_2 properties, pipelines, plants and other property and equipment	105,318	118,671	123,376
Accelerated depreciation charge (1)	591,025	—	—
Total DD&A	$ 846,043	$ 531,660	$ 592,972
DD&A per BOE			
Oil and natural gas properties	$ 6.39	$ 15.53	$ 17.29
CO_2, properties, pipelines, plants and other property and equipment	4.50	4.46	4.54
Accelerated depreciation charge (1)	25.23	—	—
Total DD&A per BOE	$ 36.12	$ 19.99	$ 21.83
Write-down of oil and natural gas properties	$ 810,921	$ 4,939,600	$ —

(1) Represents an accelerated depreciation charge associated with the Riley Ridge gas processing facility and related assets. See below for further discussion.

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. DD&A of oil and natural gas properties and asset retirement obligations decreased 64% on an absolute-dollar basis and 59% on a per-BOE basis between 2015 and 2016, primarily due to a reduction in depletable costs associated with our reserves base resulting from the significant full cost pool ceiling test write-downs recognized during 2015 and 2016, as well as an overall reduction in future development costs, partially offset by reductions in proved oil and natural gas reserve quantities. The per-BOE decrease was also partially offset by a decrease in production volumes during 2016 when compared to 2015. Due to these factors, our depletion and depreciation rate of oil and natural gas properties decreased to $5.35 per BOE during the fourth quarter of 2016.

Depletion and depreciation of our CO_2 properties, pipelines, plants and other property and equipment decreased 11% on an absolute-dollar basis during 2016 from 2015 levels, primarily due to lower depletion associated with our CO_2 properties resulting from a decrease in CO_2 production during the period, with the difference on a per-BOE basis offset by the decrease in oil and natural gas production volumes between periods.

We acquired the Riley Ridge Unit and the associated gas processing facility in 2010 and 2011 with the intent to separate for sale the natural gas and helium from the full well stream after construction of the gas processing facility was completed, and ultimately for the purpose of gaining a source of CO_2 to utilize in flooding our fields in the Rocky Mountain region. Subsequently, issues arose related to contractor performance and design failure that caused significant delays and incremental costs to complete the facility. We placed the gas processing facility into service during the fourth quarter of 2013, and we were successful in running the facility for part of 2014 before additional issues arose related to optimal operation of the facility and sulfur build-up in the gas supply wells. In mid-2014, the gas processing facility was shut-in and to date remains shut-in. During this period, we have searched for and evaluated a number of potential options in an effort to remedy the existing issues, and our evaluation is still ongoing. Our current projected costs to remedy these issues and successfully operate the gas processing facility are not commercially reasonable investments based on a variety of factors, including (1) the substantial capital expenditures required to implement any corrective option, (2) current projected commodity prices, and (3) our projections of our EOR activities and their timing, resulting CO_2 requirements and other assumptions.

Due to the extended shut-in status of the Riley Ridge gas processing facility and our recently updated analysis of cost estimates and engineering options to remedy the existing issues, we reassessed the estimated useful life of the gas processing facility and related assets during the fourth quarter of 2016 and recorded accelerated depreciation of $591.0 million to "Depletion, depreciation, and amortization" in the Consolidated Statements of Operations, which includes $55.3 million of intangible assets assigned to helium production rights at Riley Ridge. We plan to continue engineering work and analysis to determine if there are alternative options to remediate the sulfur build-up in the gas supply wells and to assess our ability to reduce the costs thereof; however, the timing of completion and results of such analysis are currently uncertain.

Write-Down of Oil and Natural Gas Properties

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 the average first-day-of-the-month oil and natural gas price for each month during a 12-month rolling period through the end of each quarterly reporting period. The average first-day-of-the-month NYMEX oil price used in estimating our proved reserves has been in a precipitous and continuing decline throughout 2015 and 2016, with the average price declining from $94.99 per Bbl at December 31, 2014, to $50.28 per Bbl at December 31, 2015, and further to $42.75 per Bbl at December 31, 2016. In addition, the first-day-of-the-month average natural gas price for the preceding 12 months was $4.30 per MMBtu at December 31, 2014, $2.63 per MMBtu at December 31, 2015, and $2.55 per MMBtu at December 31, 2016. These falling prices have led to our recognizing full cost pool ceiling test write-downs totaling $810.9 million and $4.9 billion during 2016 and 2015, respectively. We did not record a ceiling test write-down during 2014. We currently do not expect to record an additional write-down in the first quarter of 2017 if oil and natural gas prices remain at or near late-February 2017 levels, as the 12-month average prices used in determining the full cost ceiling value will have stabilized or reflect slightly higher prices in the first quarter of 2017 than in the first quarter of 2016.

See Item 1A, *Risk Factors*, and *Critical Accounting Policies and Estimates – Full Cost Method of Accounting, Depletion and Depreciation and Oil and Natural Gas Properties* for further discussion.

2015 Impairment of Goodwill

We are required to test goodwill for impairment on an interim basis when we determine that it is more likely than not that the fair value of our reporting unit is less than its carrying amount. We recorded a goodwill impairment charge of $1.3 billion during 2015, to fully impair the carrying value of our goodwill.

Other Expenses

Other expenses totaled $37.4 million during 2016, primarily comprised of a $27.5 million cash payment to Evolution Petroleum Corporation pursuant to a settlement agreement entered into in June 2016. See Note 10, *Commitments and Contingencies*, to the Consolidated Financial Statements for further discussion.

Income Taxes

	Year Ended December 31,		
In thousands, except per-BOE amounts and tax rates	2016	2015	2014
Current income tax benefit	$ (785)	$ (8,355)	$ (42,907)
Deferred income tax expense (benefit)	(543,385)	(1,932,179)	429,973
Total income tax expense (benefit)	$ (544,170)	$ (1,940,534)	$ 387,066
Average income tax expense (benefit) per BOE	$ (23.23)	$ (72.97)	$ 14.25
Effective tax rate	35.8%	30.7%	37.9%
Total net deferred tax liability	$ 293,878	$ 852,089	$ 2,776,569

Our income tax provisions for 2016, 2015 and 2014 were based on an estimated statutory rate of approximately 38%. Our effective tax rate was consistent with our estimated statutory rate in 2014, while our 2016 and 2015 effective tax rates were lower than the statutory rate. Effective January 1, 2016, we adopted Accounting Standards Update 2016-09 ("ASU 2016-09"), *Improvements to Employee Share-Based Payment Accounting*, which impacted the timing of when excess tax benefits or tax shortfalls are recognized. Our effective tax rate for 2016 was lower than our estimated statutory rate primarily due to the impact of a tax shortfall on the stock-based compensation deduction (e.g., the compensation expense recognized in the financial statements was greater than the actual compensation realized, resulting in a shortfall in the income tax deduction for stock awards that vested during the period). Prior to the adoption of ASU 2016-09, this was recorded as an adjustment to equity. Our effective tax rate for 2015 was lower than our estimated statutory rate, as a significant portion of the book value of our goodwill impaired during 2015 had no related tax basis. Therefore, no corresponding deferred tax benefit was recognized related to that portion of the goodwill impairment. Our effective tax rates for 2016 and 2015 were further impacted by a tax valuation allowance, which also reduced the net deferred tax benefit recognized. As of December 31, 2016, we had $36.5 million of deferred tax assets associated with State of Louisiana net operating losses. As the result of a tax law enacted in the State of Louisiana effective June 30, 2015, which limits a company's utilization of certain deductions, including our net operating loss carryforwards, we recognized tax valuation allowances totaling $33.6 million during 2015 and an additional $2.9 million during 2016 to reduce the carrying value of our deferred tax assets associated with State of Louisiana net operating losses. The valuation allowances will remain until the realization of future deferred tax benefits are more likely than not to become utilized.

As of December 31, 2016, we had an unrecognized tax benefit of $5.4 million related to an uncertain tax position. The unrecognized tax benefit was recorded during 2015 as a direct reduction of the associated deferred tax asset and, if recognized, would not materially affect our annual effective tax rate. The tax benefit from an uncertain tax position will only be recognized if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based upon the technical merits of the position. We currently do not expect a material change to the uncertain tax position within the next 12 months. Our policy is to recognize penalties and interest related to uncertain tax positions in income tax expense; however, no such amounts were accrued related to the uncertain tax position as of December 31, 2016.

The current income tax benefits recorded in 2015 and 2014 were in recognition of reinstated bonus depreciation becoming available in December 2015 and 2014, along with an increase in certain tax preference items. We currently expect to carryforward the 2015 benefits to offset taxable income in future periods. The 2014 benefit was carried back to our filed tax returns in prior years. The deferred income tax benefits during 2016 and 2015 were primarily due to the impact of the write-down of our oil and natural gas properties during the year, with 2016 further impacted by an accelerated depreciation charge associated with the Riley Ridge gas processing facility and related assets. In connection with the privately negotiated agreements to exchange a portion of our existing senior subordinated notes for 2021 Senior Secured Notes during 2016, we realized a tax gain due to the concession extended by our note holders. This tax gain was offset by net operating losses and other deferred tax asset attributes.

As of December 31, 2016, we had tax-effected federal net operating loss carryforwards ("NOLs") totaling $27.1 million, state NOLs totaling $42.6 million (before provision for valuation allowance), an estimated $51.1 million of enhanced oil recovery credits to carry forward related to our tertiary operations, $21.6 million of research and development credits, and $41.1 million of alternative minimum tax credits that can be utilized to reduce our current income taxes during 2017 or future years. Our state NOLs expire in various years, starting in 2019, although most do not begin to expire until 2036. Our enhanced oil recovery credits and research and development credits do not begin to expire until 2023 and 2031, respectively.

Per-BOE Data

The following table summarizes our cash flow 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	2016	2015	2014
Oil and natural gas revenues	$ 39.95	$ 45.61	$ 87.33
Receipt on settlements of commodity derivatives	3.59	19.24	0.05
Lease operating expenses – excluding special items	(17.71)	(19.88)	(24.10)
Lease operating expenses – special items [(1)]	—	0.51	0.26
Production and ad valorem taxes	(2.94)	(3.60)	(5.72)
Marketing expenses, net of third-party purchases, and plant operating expenses	(1.92)	(1.82)	(1.76)
Production netback	20.97	40.06	56.06
CO_2 sales, net of operating and exploration expenses	0.92	0.98	0.71
General and administrative expenses	(4.69)	(5.44)	(5.83)
Interest expense, net	(5.34)	(5.99)	(6.74)
Other	(0.58)	1.18	2.50
Changes in assets and liabilities relating to operations	(1.92)	1.71	(1.69)
Cash flows from operations	9.36	32.50	45.01
DD&A – excluding accelerated depreciation charge	(10.89)	(19.99)	(21.83)
DD&A – accelerated depreciation charge [(2)]	(25.23)	—	—
Write-down of oil and natural gas properties	(34.62)	(185.74)	—
Impairment of goodwill	—	(47.44)	—
Deferred income taxes	23.20	72.65	(15.83)
Gain (loss) on early extinguishment of debt	4.91	—	(4.19)
Noncash fair value gains (losses) on commodity derivatives [(3)]	(9.05)	(13.67)	20.39
Other noncash items	0.65	(3.21)	(0.16)
Net income (loss)	$ (41.67)	$ (164.90)	$ 23.39

(1) Represents a reimbursement for a retroactive utility rate adjustment ($9.6 million) and an insurance reimbursement for previous well control costs ($4.1 million) during 2015 and lease operating expenses and related insurance reimbursements, net, of $7.1 million during 2014.

(2) Represents an accelerated depreciation charge associated with the Riley Ridge gas processing facility and related assets. See *Depletion, Depreciation, and Amortization* above for further discussion.

(3) Noncash fair value gains (losses) on commodity derivatives is a non-GAAP measure. See *Operating Results Table* above for a discussion of the reconciliation between noncash fair value gains (losses) on commodity derivatives to "Commodity derivatives expense (income)" in the Consolidated Statements of Operations. See also the *Glossary and Selected Abbreviations* for the definition of noncash fair value gains (losses) on commodity derivatives.

MARKET RISK MANAGEMENT

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, 2016, we had $301.0 million of debt outstanding on our senior secured bank credit facility. At this level of variable-rate debt, an increase or decrease of 10% in interest rates would have an immaterial effect on our interest expense. None of our existing debt has any triggers or covenants regarding our debt ratings with rating agencies, although under the NEJD financing lease, in light of credit downgrades in February 2016, we were required to provide a $41.3 million letter of credit to the lessor, which we provided on March 4, 2016. The letter of credit may be drawn upon in the event Denbury Onshore or Denbury fail to make a payment due under the pipeline financing lease agreement or upon other specified defaults set out in the pipeline financing lease agreement (filed as Exhibit 99.1 to the Form 8-K filed with the SEC on June 5, 2008). The fair values of our senior secured second lien notes and 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, 2016:

In thousands	2017	2019	2021	2022	2023	Total	Fair Value
Variable rate debt							
Senior Secured Bank Credit Facility (weighted average interest rate of 3.0% at December 31, 2016)	$ —	$ 301,000	$ —	$ —	$ —	$ 301,000	$ 301,000
Fixed rate debt							
9% Senior Secured Second Lien Notes due 2021	—	—	614,919	—	—	614,919	657,164
6⅜% Senior Subordinated Notes due 2021	—	—	215,144	—	—	215,144	193,630
5½% Senior Subordinated Notes due 2022	—	—	—	772,912	—	772,912	674,366
4⅝% Senior Subordinated Notes due 2023	—	—	—	—	622,297	622,297	499,393
Other Subordinated Notes	2,250	—	—	—	—	2,250	2,250

Oil and Natural Gas Derivative Contracts

Historically, we have entered 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 and to provide more certainty to our future cash flows. We do not hold or issue derivative financial instruments for trading purposes. Generally, these contracts have consisted of various combinations of price floors, collars, three-way collars, fixed-price swaps, and fixed-price swaps enhanced with a sold put. The production that we hedge has varied from year to year depending on our levels of debt, financial strength, and expectation of future commodity prices. In order to provide a level of price protection to a portion of our oil production, we have hedged a portion of our estimated oil production through 2017 using both NYMEX and LLS fixed-price swaps, collars and three-way collars. See also Note 8, *Commodity Derivative Contracts*, and Note 9*, Fair Value Measurements,* to the Consolidated Financial Statements for additional information regarding our commodity derivative contracts.

All of the mark-to-market valuations used for our commodity 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 senior secured bank credit facility (or affiliates of such lenders). We have included an estimate of nonperformance risk in the fair value measurement of our commodity 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 commodity 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, 2016, our commodity derivative contracts were recorded at their fair value, which was a net liability of $69.3 million, a $212.1 million decrease from the $142.8 million net asset recorded at December 31, 2015. This change is primarily related to the expiration of commodity derivative contracts during 2016, new commodity derivative contracts entered into during 2016 for future periods, and changes in oil futures prices between December 31, 2015 and 2016.

Commodity Derivative Sensitivity Analysis

Based on NYMEX and LLS crude oil futures prices as of December 31, 2016, and assuming both a 10% increase and decrease thereon, we would expect to make payments on our crude oil derivative contracts as shown in the following table:

In thousands	Payment
Based on:	
Futures prices as of December 31, 2016	$ (67,476)
10% increase in prices	(101,247)
10% decrease in prices	(36,565)

Our commodity derivative contracts are used as an economic hedge of our exposure to commodity price risk associated with anticipated future production. As a result, changes in receipts or payments of our commodity derivative contracts due to changes in commodity prices as reflected in the above table would be mostly offset by a corresponding increase or decrease in the cash receipts on sales of our oil and natural gas production to which those commodity derivative contracts relate.

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 *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 a 12-month rolling period through the end 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 hedging 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 revisions in estimated oil and natural gas volumes, changes in ownership interests, payouts, joint venture audits, re-allocations by the purchasers or pipelines, 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 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, excluding any revisions related to changes in commodity prices, have averaged approximately 1.9% of the previous year's estimates and have been both positive and negative.

Changes in commodity prices also affect our reserve quantities. 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 reserve quantities would have lowered our fourth quarter 2016 DD&A rate from $5.35 per BOE to approximately $5.12 per BOE, and a 5% decrease in our proved reserve quantities would have increased our DD&A rate to approximately $5.60 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 senior secured bank credit facility, particularly quantities and values of our proved developed producing reserves.

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 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 a 12-month rolling 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 we do not have to incur additional costs to develop the proved oil and natural gas reserves. 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 hedging instruments for accounting purposes. The cost center ceiling test is prepared quarterly.

The average first-day-of-the-month NYMEX oil price used in estimating our proved reserves has precipitously and continually declined throughout 2015 and 2016, with the average price declining from $94.99 per Bbl at December 31, 2014, to $50.28 per Bbl at December 31, 2015, and further to $42.75 per Bbl at December 31, 2016. In addition, the first-day-of-the-month average natural gas price for the preceding 12 months was $4.30 per MMBtu at December 31, 2014, $2.63 per MMBtu at December 31, 2015, and $2.55 per MMBtu at December 31, 2016. These falling prices have led to our recognizing full cost pool ceiling test write-downs totaling $810.9 million and $4.9 billion during 2016 and 2015, respectively. We did not record a ceiling test write-down during 2014. We currently do not expect to record an additional write-down in the first quarter of 2017 if oil and natural gas prices remain at or near late-February 2017 levels, as the 12-month average prices used in determining the full cost ceiling value will have stabilized or reflect slightly higher prices in the first quarter of 2017 than in the first quarter of 2016.

We exclude certain unevaluated costs from the amortization base and full cost ceiling test pending the determination of whether proved reserves can be assigned to such properties. These costs are transferred to the full cost amortization base in the course of these properties being developed, tested and evaluated. At least annually, we test these assets for impairment based on an evaluation of management's expectations of future pricing, evaluation of lease expiration terms, and planned project development activities. As a result of this analysis, we recognized impairments of \$21.0 million and \$17.9 million of our unevaluated costs during the years ended December 31, 2016 and 2015, respectively, whereby these costs were transferred to the full cost amortization base. We did not have an impairment of our unevaluated costs for the year ended December 31, 2014.

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 2016, 2015 and 2014, we capitalized \$17.3 million, \$19.4 million and \$20.7 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 the result of a new tax law enacted in the State of Louisiana effective June 30, 2015, which limits a company's utilization of certain deductions, including our net operating loss carryforwards, we recognized tax valuation allowances totaling \$33.6 million during 2015 and an additional \$2.9 million during 2016 to reduce the carrying value of our deferred tax assets. The valuation allowances will remain until the realization of future deferred tax benefits are more likely than not to become utilized. A 1% increase in our effective tax rate would have increased our calculated income tax expense (benefit) by approximately (\$15.2 million), (\$63.3 million) and \$10.2 million for the years ended December 31, 2016, 2015 and 2014, respectively. See Note 5, *Income Taxes*, to the Consolidated Financial Statements and *Results of Operations – 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 9, *Fair Value Measurements*, to the Consolidated Financial Statements for disclosures regarding our recurring fair value measurements.

Significant uses of fair value measurements include:

- assessment of impairment of long-lived assets; and
- recorded value of commodity derivative instruments.

Impairment Assessment of Long-Lived Assets

We test long-lived assets for impairment that are not subject to our quarterly full cost pool ceiling test, including a portion of our capitalized CO_2 properties and pipelines, whenever events or changes in circumstances indicate that the carrying value may not be recoverable. The factors we assess to determine if a long-lived asset impairment test is necessary include, among other factors, a significant adverse change in the business climate that could affect the value of a long-lived asset, a significant decrease in the market price of an asset group, a significant adverse change in the extent or manner in which a long-lived asset (asset group) is being used or in its physical condition, or a current-period operating or cash flow loss combined with a history of operating or cash flow losses or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset (asset group).

We perform our long-lived asset impairment test by comparing the net carrying costs of our long-lived asset groups to the respective expected future undiscounted net cash flows that are supported by these long-lived assets which include production of our probable and possible oil and natural gas reserves. If the undiscounted net cash flows are below the net carrying costs for an asset group, we must record an impairment loss by the amount, if any, that net carrying costs exceed the fair value of the long-lived asset group. Management assumptions impacting expected future undiscounted net cash flows include market estimates of future commodity prices, projections of estimated reserve quantities, 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-adjustment factors applied to the net cash flows. Due to an increase in cost estimates to correct and remedy the sulfur deposition issues at Riley Ridge provided in the results of preliminary engineering design efforts received late in 2016 and the potential impact on the utilization of Riley Ridge assets within the Rocky Mountain asset group, we performed a long-lived asset impairment test for the Rocky Mountain asset group during the fourth quarter of 2016. The undiscounted net cash flows for our asset group exceeded the net carrying costs; thus, step two of the impairment test was not required and no impairment was recorded.

We acquired the Riley Ridge Unit and the associated gas processing facility in 2010 and 2011 with the intent to separate for sale the natural gas and helium from the full well stream after construction of the gas processing facility was completed, and ultimately for the purpose of gaining a source of CO_2 to utilize in flooding our fields in the Rocky Mountain region. Subsequently, issues arose related to contractor performance and design failure that caused significant delays and incremental costs to complete the facility. We placed the gas processing facility into service during the fourth quarter of 2013, and we were successful in running the facility for part of 2014 before additional issues arose related to optimal operation of the facility and sulfur build-up in the gas supply wells. In mid-2014, the gas processing facility was shut-in and to date remains shut-in. During this period, we have searched for and evaluated a number of potential options in an effort to remedy the existing issues, and our evaluation is still ongoing. Our current projected costs to remedy these issues and successfully operate the gas processing facility are not commercially reasonable investments based on a variety of factors, including (1) the substantial capital expenditures required to implement any corrective option, (2) current projected commodity prices, and (3) our projections of our EOR activities and their timing, resulting CO_2 requirements and other assumptions.

Due to the extended shut-in status of the Riley Ridge gas processing facility and our recently updated analysis of cost estimates and engineering options to remedy the existing issues, we reassessed the estimated useful life of the gas processing facility and related assets during the fourth quarter of 2016 and recorded accelerated depreciation of $591.0 million to "Depletion, depreciation, and amortization" in the Consolidated Statements of Operations, which includes $55.3 million of intangible assets assigned to helium production rights at Riley Ridge. We plan to continue engineering work and analysis to determine if there are alternative options to remediate the sulfur build-up in the gas supply wells and to assess our ability to reduce the costs thereof; however, the timing of completion and results of such analysis are currently uncertain.

Oil and Natural Gas Derivative Contracts

Historically, we have entered into oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with future oil and natural gas production and to provide more certainty to our future cash flows. We do not hold or issue derivative financial instruments for trading purposes. Generally, these contracts have consisted of various combinations of price floors, collars, three-way collars, fixed-price swaps and fixed-price swaps enhanced with a sold put. Our derivative financial instruments are recorded on the balance sheet as either an asset or liability measured at fair value. The valuation methods used to measure the fair values of these assets and liabilities require considerable management judgment and estimates to derive the inputs necessary to determine fair value estimates, such as forward prices for commodities, interest rates, volatility factors and credit worthiness, as well as other relevant economic measures. We do not apply hedge accounting to our commodity derivative contracts under the FASC *Derivatives and Hedging* topic; accordingly, changes in the fair value of these instruments are recognized in 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 (loss) 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 recent accounting pronouncements.

FORWARD-LOOKING INFORMATION

The data and/or 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 Properties" 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 Exchange Act of 1934, as amended (the "Exchange Act"), that involve a number of risks and uncertainties. Such forward-looking statements may be or may concern, among other things, financial forecasts, future hydrocarbon prices and timing and degree of any price recovery versus the length or severity of the current commodity price downturn, current or future liquidity sources or their adequacy to support our anticipated future activities, our ability to further reduce our debt levels, possible future write-downs of oil and natural gas reserves, together with assumptions based on current and projected oil and gas prices and oilfield costs, current or future expectations or estimations of our cash flows, availability of capital, borrowing capacity, future interest rates, availability of advantageous commodity derivative contracts or the predicted cash flow benefits therefrom, forecasted capital expenditures, drilling activity or methods, including the timing and location thereof, estimated timing of commencement of CO_2 flooding of particular fields or areas, dates of completion of to-be-constructed industrial plants and the initial date of capture of 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, anticipated future cost savings, capital budgets, interpretation or prediction of formation details, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO_2 reserves and supply and their availability, potential reserves, barrels or percentages of recoverable original oil in place, potential increases in regional or worldwide tariffs or other trade restrictions, the likelihood, timing and impact of increased interest rates, the impact of regulatory rulings or changes, anticipated outcomes of pending litigation, prospective legislation affecting the oil and gas industry, environmental regulations, mark-to-market values, competition, long-term forecasts of production, rates of return, estimated costs, changes in costs, future capital expenditures and overall economics, worldwide economic conditions and other variables surrounding our estimated original oil in place, operations and future plans. Such forward-looking statements generally are accompanied by words such as "plan," "estimate," "expect," "predict," "forecast," "to our knowledge," "anticipate," "projected," "preliminary," "should," "assume," "believe," "may" or other words that convey, or are intended to 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 and adversely 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 in worldwide oil prices or in U.S. oil prices and consequently in the prices received or demand for our oil and natural gas; decisions as to production levels and/or pricing by OPEC in future periods; levels of future capital expenditures; 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 and remediation costs; disruption of operations and damages from well incidents, hurricanes, tropical storms, or forest fires; acquisition risks; requirements for capital or its availability; conditions in the worldwide financial, trade and credit markets; general economic conditions; competition; government regulations, including tax and environmental; 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, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 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, 2016, based on criteria established in *Internal Control – Integrated Framework (2013)* 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.

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP
Dallas, Texas
March 1, 2017

Denbury Resources Inc.
Consolidated Balance Sheets
(In thousands, except par value and share data)

	December 31, 2016	December 31, 2015
Assets		
Current assets		
Cash and cash equivalents	$ 1,606	$ 2,812
Accrued production receivable	124,936	100,413
Trade and other receivables, net	43,900	87,093
Derivative assets	—	142,846
Other current assets	10,684	10,005
Total current assets	181,126	343,169
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved properties	10,419,827	10,245,195
Unevaluated properties	927,819	894,948
CO_2 properties	1,188,467	1,187,458
Pipelines and plants	2,285,812	2,293,219
Other property and equipment	378,776	408,194
Less accumulated depletion, depreciation, amortization and impairment	(11,212,327)	(9,653,205)
Net property and equipment	3,988,374	5,375,809
Other assets	105,078	166,555
Total assets	$ 4,274,578	$ 5,885,533
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 200,266	$ 253,197
Oil and gas production payable	80,585	87,337
Derivative liabilities	69,279	—
Current maturities of long-term debt (including future interest payable of $50,349 and $0, respectively – see Note 4)	83,366	32,481
Total current liabilities	433,496	373,015
Long-term liabilities		
Long-term debt, net of current portion (including future interest payable of $178,476 and $0, respectively – see Note 4)	2,909,732	3,245,114
Asset retirement obligations	146,807	138,919
Deferred tax liabilities, net	293,878	852,089
Other liabilities	22,217	27,484
Total long-term liabilities	3,372,634	4,263,606
Commitments and contingencies (Note 10)		
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; 402,334,655 and 354,541,626 shares issued, respectively	402	355
Paid-in capital in excess of par	2,534,670	2,353,549
Accumulated deficit	(2,018,989)	(1,058,954)
Treasury stock, at cost, 3,906,877 and 3,124,311 shares, respectively	(47,635)	(46,038)
Total stockholders' equity	468,448	1,248,912
Total liabilities and stockholders' equity	$ 4,274,578	$ 5,885,533

See accompanying Notes to Consolidated Financial Statements.

Denbury Resources Inc.
Consolidated Statements of Operations
(In thousands, except per share data)

	Year Ended December 31,		
	2016	2015	2014
Revenues and other income			
Oil, natural gas, and related product sales	$ 935,751	$ 1,213,026	$ 2,372,473
CO_2 sales and transportation fees	24,816	30,626	44,643
Interest income and other income	15,029	13,908	18,089
Total revenues and other income	975,596	1,257,560	2,435,205
Expenses			
Lease operating expenses	414,937	515,043	647,559
Marketing and plant operating expenses	57,454	55,746	64,379
CO_2 discovery and operating expenses	3,374	4,557	25,222
Taxes other than income	77,892	109,992	169,701
General and administrative expenses	109,926	144,564	158,343
Interest, net of amounts capitalized of $25,982, $32,146 and $24,202, respectively	125,145	159,268	183,003
Depletion, depreciation, and amortization	846,043	531,660	592,972
Commodity derivatives expense (income)	127,944	(147,999)	(555,255)
Loss (gain) on debt extinguishment	(115,095)	—	113,908
Write-down of oil and natural gas properties	810,921	4,939,600	—
Impairment of goodwill	—	1,261,512	—
Other expenses	37,402	9,599	12,816
Total expenses	2,495,943	7,583,542	1,412,648
Income (loss) before income taxes	(1,520,347)	(6,325,982)	1,022,557
Income tax provision (benefit)	(544,170)	(1,940,534)	387,066
Net income (loss)	$ (976,177)	$ (4,385,448)	$ 635,491
Net income (loss) per common share			
Basic	$ (2.61)	$ (12.57)	$ 1.82
Diluted	$ (2.61)	$ (12.57)	$ 1.81
Dividends declared per common share	$ —	$ 0.1875	$ 0.2500
Weighted average common shares outstanding			
Basic	373,859	348,802	348,962
Diluted	373,859	348,802	351,167

See accompanying Notes to Consolidated Financial Statements.

Denbury Resources Inc.
Consolidated Statements of Comprehensive Operations
(In thousands)

	Year Ended December 31,		
	2016	2015	2014
Net income (loss)	$ (976,177)	$ (4,385,448)	$ 635,491
Other comprehensive income, net of income tax			
Interest rate lock derivative contracts reclassified to income, net of tax of $0, $128 and $45, respectively	—	209	67
Total other comprehensive income	—	209	67
Comprehensive income (loss)	$ (976,177)	$ (4,385,239)	$ 635,558

See accompanying Notes to Consolidated Financial Statements.

Denbury Resources Inc.
Consolidated Statements of Cash Flows
(In thousands)

	Year Ended December 31,		
	2016	2015	2014
Cash flows from operating activities			
Net income (loss)	$ (976,177)	$ (4,385,448)	$ 635,491
Adjustments to reconcile net income (loss) to cash flows from operating activities			
Depletion, depreciation, and amortization	846,043	531,660	592,972
Write-down of oil and natural gas properties	810,921	4,939,600	—
Impairment of goodwill	—	1,261,512	—
Deferred income taxes	(543,385)	(1,932,179)	429,973
Stock-based compensation	14,995	30,604	30,513
Commodity derivatives expense (income)	127,944	(147,999)	(555,255)
Receipt on settlements of commodity derivatives	84,181	511,699	1,421
Loss (gain) on debt extinguishment	(115,095)	—	113,908
Debt issuance costs and discounts	17,006	9,121	13,476
Other, net	(2,161)	343	6,311
Changes in assets and liabilities, net of effects from acquisitions			
Accrued production receivable	(24,290)	81,213	80,285
Trade and other receivables	35,923	67,047	(78,469)
Other current and long-term assets	(8,661)	241	3,174
Accounts payable and accrued liabilities	(34,240)	(55,234)	501
Oil and natural gas production payable	(6,752)	(40,833)	(46,506)
Other liabilities	(7,029)	(7,043)	(4,970)
Net cash provided by operating activities	219,223	864,304	1,222,825
Cash flows from investing activities			
Oil and natural gas capital expenditures	(243,027)	(476,398)	(946,846)
Acquisitions of oil and natural gas properties	(1,310)	(21,876)	(8,773)
CO_2 capital expenditures	(2,321)	(26,301)	(48,134)
Pipelines and plants capital expenditures	(2,666)	(31,728)	(72,151)
Purchases of other assets	(3,586)	(5,492)	(3,197)
Net proceeds from sales of oil and natural gas properties and equipment	47,725	563	3,453
Other	(232)	11,047	(1,107)
Net cash used in investing activities	(205,417)	(550,185)	(1,076,755)
Cash flows from financing activities			
Bank repayments	(1,730,500)	(1,862,000)	(2,609,000)
Bank borrowings	1,856,500	1,642,000	2,664,000
Interest payments on senior secured notes treated as a reduction of debt	(25,835)	—	—
Repayment or repurchases of senior subordinated notes	(76,708)	(485)	(997,345)
Premium paid on repayment of senior subordinated notes	—	—	(101,342)
Proceeds from issuance of senior subordinated notes	—	—	1,250,000
Costs of debt financing	(9,574)	(1,668)	(24,407)
Common stock repurchase program	—	(11,759)	(211,356)
Pipeline financing and capital lease debt repayments	(28,849)	(33,642)	(33,381)
Cash dividends paid	(486)	(65,426)	(87,044)
Other	440	(1,480)	14,771
Net cash used in financing activities	(15,012)	(334,460)	(135,104)
Net increase (decrease) in cash and cash equivalents	(1,206)	(20,341)	10,966
Cash and cash equivalents at beginning of year	2,812	23,153	12,187
Cash and cash equivalents at end of year	$ 1,606	$ 2,812	$ 23,153

See accompanying Notes to Consolidated Financial Statements.

Denbury Resources Inc.
Consolidated Statements of Changes in Stockholders' Equity
(Dollar amounts in thousands)

	Common Stock ($.001 Par Value)		Paid-In Capital in Excess of Par	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Treasury Stock (at cost)		Total Equity
	Shares	Amount				Shares	Amount	
Balance – December 31, 2013	409,215,573	$ 409	$ 3,186,714	$ 2,844,432	$ (276)	46,710,896	$ (729,873)	$ 5,301,406
Stock Repurchase Program	—	—	—	—	—	12,398,017	(200,369)	(200,369)
Issued or purchased pursuant to stock compensation plans	2,541,809	3	7,020	—	—	—	—	7,023
Issued pursuant to employee stock purchase plan	—	—	(3,272)	—	—	(1,247,156)	19,630	16,358
Issued pursuant to directors' compensation plan	22,529	—	412	—	—	—	—	412
Stock-based compensation	—	—	39,532	—	—	—	—	39,532
Income tax benefit from equity awards	—	—	12	—	—	—	—	12
Tax withholding – stock compensation	—	—	—	—	—	553,750	(8,618)	(8,618)
Derivative contracts, net	—	—	—	—	67	—	—	67
Cash dividends declared ($0.25 per common share)	—	—	—	(87,458)	—	—	—	(87,458)
Net income	—	—	—	635,491	—	—	—	635,491
Balance – December 31, 2014	411,779,911	412	3,230,418	3,392,465	(209)	58,415,507	(919,230)	5,703,856
Stock Repurchase Program	—	—	—	—	—	4,424,702	(11,759)	(11,759)
Issued or purchased pursuant to stock compensation plans	3,900,127	5	562	—	—	—	—	567
Issued pursuant to employee stock purchase plan	—	—	(2,867)	—	—	(353,480)	5,534	2,667
Issued pursuant to directors' compensation plan	292,407	—	398	—	—	—	—	398
Share correction	(1,430,819)	(2)	(22,076)	—	—	—	—	(22,078)
Stock-based compensation	—	—	39,285	—	—	—	—	39,285
Income tax shortfall from equity awards	—	—	(8,102)	—	—	—	—	(8,102)
Tax withholding – stock compensation	—	—	—	—	—	637,582	(4,712)	(4,712)
Derivative contracts, net	—	—	—	—	209	—	—	209
Cash dividends declared ($0.1875 per common share)	—	—	—	(65,971)	—	—	—	(65,971)
Retirement of treasury stock	(60,000,000)	(60)	(884,069)	—	—	(60,000,000)	884,129	—
Net loss	—	—	—	(4,385,448)	—	—	—	(4,385,448)
Balance – December 31, 2015	354,541,626	355	2,353,549	(1,058,954)	—	3,124,311	(46,038)	1,248,912
Cumulative effect of accounting change	—	—	(415)	16,072	—	—	—	15,657
Issued or purchased pursuant to stock compensation plans	7,031,767	7	(7)	—	—	—	—	—
Issued pursuant to directors' compensation plan	31,930	—	50	—	—	—	—	50
Issued as part of debt exchange	40,729,332	40	160,451	—	—	—	—	160,491
Stock-based compensation	—	—	21,042	—	—	—	—	21,042
Tax withholding – stock compensation	—	—	—	—	—	782,566	(1,597)	(1,597)
Dividends adjustments	—	—	—	70	—	—	—	70
Net loss	—	—	—	(976,177)	—	—	—	(976,177)
Balance – December 31, 2016	402,334,655	$ 402	$ 2,534,670	$ (2,018,989)	$ —	3,906,877	$ (47,635)	$ 468,448

See accompanying Notes to Consolidated Financial Statements.

Note 1. Significant Accounting Policies

Organization and Nature of Operations

Denbury Resources Inc., a Delaware corporation, is an independent oil and natural gas company with operations focused in two key operating areas: the Gulf Coast and Rocky Mountain regions. Our goal is to increase the value of our properties through a combination of exploitation, drilling and proven engineering extraction practices, with the most significant emphasis relating to CO_2 enhanced oil 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) future net cash flow estimates used in the impairment assessment of long-lived assets; (4) the estimated quantities of proved and probable CO_2 reserves used to compute depletion of CO_2 properties; (5) estimated useful lives used to compute depreciation and amortization of long-lived assets; (6) accruals related to oil and natural gas sales volumes and revenues, capital expenditures and lease operating expenses; (7) the estimated costs and timing of future asset retirement obligations; (8) estimates made in the calculation of income taxes; and (9) 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 current year-end 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. On the Consolidated Balance Sheets, (1) debt issuance costs associated with our senior subordinated notes have been reclassified from "Other assets" to "Long-term debt, net of current portion" and (2) deferred tax assets have been reclassified from "Deferred tax assets, net" to "Deferred tax liabilities, net." Such reclassifications were made as a result of our adoption of new accounting pronouncements described in *Recent Accounting Pronouncements – Recently Adopted* below and had no impact on our previously reported net income (loss) or cash flows.

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.

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 the acquisition, 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 Measurement* 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. At least annually, we test these assets for impairment based on an evaluation of management's expectations of future pricing, evaluation of lease expiration terms, and planned project development activities. As a result of this analysis, we recognized impairments of our unevaluated costs totaling $21.0 million and $17.9 million during the years ended December 31, 2016 and 2015, respectively, whereby these costs were transferred to the full cost amortization base. We did not have an impairment of our unevaluated costs during the year ended December 31, 2014.

Write-Down of Oil and Natural Gas Properties. 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 a 12-month rolling 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 we do not have to incur additional costs to develop the proved oil and natural gas reserves. 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.

The average first-day-of-the-month NYMEX oil price used in estimating our proved reserves has been in a precipitous and continuing decline throughout 2015 and 2016, with the average price declining from $94.99 per Bbl at December 31, 2014, to $50.28 per Bbl at December 31, 2015, and further to $42.75 per Bbl at December 31, 2016. In addition, the first-day-of-the-month average natural gas price for the preceding 12 months was $4.30 per MMBtu at December 31, 2014, $2.63 per MMBtu at December 31, 2015, and $2.55 per MMBtu at December 31, 2016. These falling prices have led to our recognizing full cost pool ceiling test write-downs totaling $810.9 million and $4.9 billion during 2016 and 2015, respectively. We did not record a ceiling test write-down during 2014.

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 we can demonstrate production resulting from the tertiary process 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 natural 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.

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. Capitalized costs include \$100.3 million of CO_2 pipelines as of December 31, 2016, that were under construction and not subject to depreciation during 2016.

We acquired the Riley Ridge Unit and the associated gas processing facility in 2010 and 2011 with the intent to separate for sale the natural gas and helium from the full well stream after construction of the gas processing facility was completed, and ultimately for the purpose of gaining a source of CO_2 to utilize in flooding our fields in the Rocky Mountain region. Subsequently, issues arose related to contractor performance and design failure that caused significant delays and incremental costs to complete the facility. We placed the gas processing facility into service during the fourth quarter of 2013, and we were successful in running the facility for part of 2014 before additional issues arose related to optimal operation of the facility and sulfur build-up in the gas supply wells. In mid-2014, the gas processing facility was shut-in and to date remains shut-in. During this period, we have searched for and evaluated a number of potential options in an effort to remedy the existing issues, and our evaluation is still ongoing. Our current projected costs to remedy these issues and successfully operate the gas processing facility are not commercially reasonable investments based on a variety of factors, including (1) the substantial capital expenditures required to implement any corrective option, (2) current projected commodity prices, and (3) our projections of our EOR activities and their timing, resulting CO_2 requirements and other assumptions.

Due to the extended shut-in status of the Riley Ridge gas processing facility and our recently updated analysis of cost estimates and engineering options to remedy the existing issues, we reassessed the estimated useful life of the gas processing facility and related assets during the fourth quarter of 2016 and recorded accelerated depreciation of \$591.0 million to "Depletion, depreciation, and amortization" in the Consolidated Statements of Operations, which includes \$55.3 million of intangible assets assigned to helium production rights at Riley Ridge. We plan to continue engineering work and analysis to determine if there are alternative options to remediate the sulfur build-up in the gas supply wells and to assess our ability to reduce the costs thereof; however, the timing of completion and results of such analysis are currently uncertain.

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 lease term.

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

Goodwill and Other Intangible Assets

Goodwill previously recorded on our Consolidated Balance Sheets represented the excess of the purchase price over the estimated fair value of the net assets acquired in the acquisition of businesses. Goodwill was not amortized; rather, it was tested for impairment annually during the fourth quarter or when events or changes in circumstances indicated that it was more likely than not the fair value of a reporting unit with goodwill was reduced below its carrying value. Because the fair value of the reporting unit (enterprise value) did not exceed the fair value of assets and liabilities, we recorded a goodwill impairment charge of $1.3 billion during 2015 to fully impair the carrying value of our goodwill.

Our intangible asset subject to amortization primarily consists of amounts assigned in purchase accounting to a CO_2 purchase contract with ConocoPhillips to offtake CO_2 from the Lost Cabin gas plant in Wyoming and is included in our Consolidated Balance Sheets under the caption "Other assets." We amortize the CO_2 contract intangible asset on a straight-line basis over the contract term. Total amortization expense related to this asset was $2.3 million during the years ended December 31, 2016 and 2015. The following table summarizes the carrying value of our CO_2 purchase contract intangible asset as of December 31, 2016 and 2015:

	December 31,	
In thousands	2016	2015
Intangible asset value	$ 34,341	$ 34,341
Accumulated amortization	(8,203)	(5,915)
Net book value	$ 26,138	$ 28,426

As of December 31, 2016, our estimated amortization expense for our intangible asset subject to amortization over the next five years is as follows:

In thousands	
2017	$ 2,289
2018	2,289
2019	2,289
2020	2,289
2021	2,289

Impairment Assessment of Long-Lived Assets

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 and natural gas reserves is included in the full cost pool ceiling test as a reduction to future net revenues. The remaining net capitalized costs that are not included in the full cost pool ceiling test, and related intangible assets, are subject to long-lived asset impairment testing whenever events or changes in circumstances indicate that the carrying value may not be recoverable.

We perform our long-lived asset impairment test by comparing the net carrying costs of our long-lived asset groups to the respective expected future undiscounted net cash flows that are supported by these long-lived assets which include production of our probable and possible oil and natural gas reserves. If the undiscounted net cash flows are below the net carrying costs for an asset group, we must record an impairment loss by the amount, if any, that net carrying costs exceed the fair value of the long-lived asset group.

Due to an increase in cost estimates to correct and remedy the sulfur deposition issues at Riley Ridge provided in the results of preliminary engineering design efforts received late in 2016 and the potential impact on the utilization of Riley Ridge assets within the Rocky Mountain asset group, we performed a long-lived asset impairment test for the Rocky Mountain asset group during the fourth quarter of 2016. Significant assumptions impacting expected future undiscounted net cash flows include projections of future commodity prices, projections of estimated reserve quantities, 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-adjustment factors applied to the net cash flows. The undiscounted net cash flows for our asset group exceeded the net carrying costs; thus, step two of the impairment test was not required and no impairment was recorded.

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 for an oil or natural gas well 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. 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 Measurement* 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, collars or three-way collars, fixed-price swaps and fixed-price swaps enhanced with a sold put. 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 commodity derivative contracts; accordingly, changes in the fair value of these instruments are recognized in our Consolidated Statements of Operations in the period of change.

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 parties that are lenders under our senior secured bank credit facility (or affiliates of such lenders). There are no margin requirements with the counterparties of our derivative contracts.

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 would not expect the loss of any purchaser to have a material adverse effect upon our operations. For the year ended December 31, 2016, two purchasers accounted for 10% or more of our oil and natural gas revenues: Plains Marketing LP (20%) and Marathon Petroleum Company (14%). For the year ended December 31, 2015, two purchasers accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company (28%) and Plains Marketing LP (15%). For the year ended December 31, 2014, three purchasers accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company (31%), Plains Marketing LP (13%), and ConocoPhillips (12%).

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 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, 2016 and 2015, 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.

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 (Loss) per Common Share

Basic net income (loss) per common share is computed by dividing the net income (loss) attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted net income (loss) per common share is calculated in the same manner, but includes the impact of potentially dilutive securities. Potentially dilutive securities consist of nonvested restricted stock, stock options, stock appreciation rights (“SARs”), and nonvested performance-based equity awards. For each of the three years in the period ended December 31, 2016, there were no adjustments to net income (loss) for purposes of calculating basic and diluted net income (loss) per common share.

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

	Year Ended December 31,		
In thousands	2016	2015	2014
Basic weighted average common shares outstanding	373,859	348,802	348,962
Potentially dilutive securities			
Restricted stock, stock options, SARs and performance-based equity awards	—	—	2,205
Diluted weighted average common shares outstanding	373,859	348,802	351,167

Basic weighted average common shares exclude shares of nonvested restricted stock. As these restricted shares vest, they will be included in the shares outstanding used to calculate basic net income (loss) per common share (although time-vesting restricted stock is issued and outstanding upon grant). For purposes of calculating diluted weighted average common shares during the year ended December 31, 2014, the nonvested restricted stock, stock options, SARs, and performance-based equity awards are included in the computation using the treasury stock method, with the deemed proceeds equal to the average unrecognized compensation during the period, the purchase price that the grantee will pay in the future for stock options, and any estimated future tax consequences recognized directly in equity.

The following securities could potentially dilute earnings per share in the future, but were excluded from the computation of diluted net income (loss) per share, as their effect would have been antidilutive:

	Year Ended December 31,		
In thousands	2016	2015	2014
Stock options and SARs	6,427	9,619	4,775
Restricted stock and performance-based equity awards	5,816	3,867	417

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

Recently Adopted

Going Concern. In August 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2014-15, *Presentation of Financial Statements – Going Concern* ("ASU 2014-15"). ASU 2014-15 requires management to assess an entity's ability to continue as a going concern by incorporating and expanding upon certain principles that are currently in United States auditing standards. The amendments in this ASU are effective beginning in the fourth quarter of 2016, and for annual and interim periods thereafter. Effective December 31, 2016, we adopted ASU 2014-15. The adoption of ASU 2014-15 did not have an impact on our disclosures for the current period consolidated financial statements, as management has concluded there are no conditions or events raising substantial doubt about our ability to continue as a going concern within one year after these financial statements are being issued.

Stock Compensation. In March 2016, the FASB issued ASU 2016-09, *Improvements to Employee Share-Based Payment Accounting* ("ASU 2016-09"). ASU 2016-09 simplifies the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The amendments in this ASU are effective for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years, and early adoption is permitted. The standard contains various amendments, each requiring a specific method of adoption, and designates whether each amendment should be adopted using a retrospective, modified retrospective, or prospective transition method. Effective January 1, 2016, we adopted ASU 2016-09. The amendments within ASU 2016-09 related to the timing of when excess tax benefits are recognized and accounting for forfeitures were adopted using a modified retrospective method. In accordance with this method, we recorded a cumulative-effect adjustment in our Consolidated Balance Sheet on January 1, 2016, relating to the timing of recognition of excess tax benefits, representing a $15.7 million reduction to beginning "Accumulated deficit" with the offset to "Deferred tax liabilities, net" ($14.8 million) and "Other current assets" ($0.8 million). We also recorded a cumulative-effect adjustment in our Consolidated Balance Sheet on January 1, 2016, to reflect actual forfeitures versus the previously-estimated forfeiture rate, representing a $0.4 million reduction to "Accumulated deficit" with the offset to "Paid-in capital in excess of par." The amendments within ASU 2016-09 related to the recognition of excess tax benefits and tax shortfalls in the income statement and presentation of excess tax benefits on the statement of cash flows were adopted prospectively, with no adjustments made to prior periods.

Income Taxes. In November 2015, the FASB issued ASU 2015-17, *Income Taxes* ("ASU 2015-17"). ASU 2015-17 simplifies the presentation of deferred income taxes and requires deferred tax assets and liabilities to be classified as noncurrent in the balance sheet. The amendments in this ASU are effective for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years, and early adoption is permitted. Entities can transition to the standard either retrospectively to each period presented or prospectively. Effective January 1, 2016, we adopted ASU 2015-17, which has been applied retrospectively for all comparative periods presented. Accordingly, current deferred tax assets of $1.5 million have been reclassified from "Deferred tax assets, net" to "Deferred tax liabilities, net" in our Consolidated Balance Sheet as of December 31, 2015. The adoption of ASU 2015-17 did not have an impact on our consolidated results of operations or cash flows.

Debt Issuance Costs. In April 2015, the FASB issued ASU 2015-03, *Interest – Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs* ("ASU 2015-03"). ASU 2015-03 requires debt issuance costs related to a recognized debt liability to be presented as a direct reduction of the carrying amount of that debt in the balance sheet, consistent with the presentation of debt discounts. The amendments in this ASU are effective for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. Entities are required to apply the guidance on a retrospective basis to each period presented as a change in accounting principle. In August 2015, the FASB issued ASU 2015-15, *Interest – Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs* ("ASU 2015-15") which amends ASU 2015-03 to clarify the presentation and subsequent measurement of debt issuance costs associated with line of credit arrangements, such that entities may continue to apply current practice. Effective January 1, 2016, we adopted ASU 2015-03 and ASU 2015-15, which have been applied retrospectively for all comparative periods presented. Accordingly, debt issuance costs of $32.8 million associated with our previously issued senior subordinated notes have been reclassified from "Other assets" to "Long-term debt, net of current portion" in our Consolidated Balance Sheet as of December 31, 2015. The adoption of ASU 2015-03 and ASU 2015-15 did not have an impact on our consolidated results of operations or cash flows for any periods.

Not Yet Adopted

Leases. In February 2016, the FASB issued ASU 2016-02, *Leases* ("ASU 2016-02"). ASU 2016-02 amends the guidance for lease accounting to require lease assets and liabilities to be recognized on the balance sheet, along with additional disclosures regarding key leasing arrangements. The amendments in this ASU are effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years, and early adoption is permitted. Entities must adopt the standard using a modified retrospective transition and apply the guidance to the earliest comparative period presented, with certain practical expedients that entities may elect to apply. Management is currently assessing the impact the adoption of ASU 2016-02 will have on our consolidated financial statements.

Revenue Recognition. In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers* ("ASU 2014-09"). ASU 2014-09 amends the guidance for revenue recognition to replace numerous, industry-specific requirements. The core principle of the ASU is that an entity should recognize revenue for the transfer of goods or services equal to the amount that it expects to be entitled to receive for those goods or services. The ASU implements a five-step process for customer contract revenue recognition that focuses on transfer of control, as opposed to transfer of risk and rewards. The amendment also requires enhanced disclosures regarding the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers. In August 2015, the FASB issued ASU 2015-14, *Revenue from Contracts with*

Customers ("ASU 2015-14") which amends ASU 2014-09 and delays the effective date for public companies, such that the amendments in the ASU are effective for reporting periods beginning after December 15, 2017, and early adoption will be permitted for periods beginning after December 15, 2016. In March, April and May 2016, the FASB issued four additional ASUs which primarily clarified the implementation guidance on principal versus agent considerations, performance obligations and licensing, collectibility, presentation of sales taxes and other similar taxes collected from customers, and non-cash consideration. Entities can transition to the standard either retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. We expect to adopt this standard using the modified retrospective method upon its effective date. Management is still evaluating the new guidance and has not yet determined the effect the standard will have on our consolidated financial statements.

Note 2. Asset Retirement Obligations

The following table summarizes the changes in our asset retirement obligations for the years ended December 31, 2016 and 2015:

	Year Ended December 31,	
In thousands	2016	2015
Beginning asset retirement obligations	$ 145,696	$ 128,095
Liabilities incurred and assumed during period	5,383	9,628
Revisions in estimated retirement obligations	6,238	5,238
Liabilities settled and sold during period	(19,878)	(6,914)
Accretion expense	11,681	9,649
Ending asset retirement obligations	149,120	145,696
Less: current asset retirement obligations (1)	(2,313)	(6,777)
Long-term asset retirement obligations	$ 146,807	$ 138,919

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

Liabilities assumed relate to minor acquisitions, with liabilities incurred generally relating to wells and facilities.

We have escrow accounts that are legally restricted for certain of our asset retirement obligations. The balances of these escrow accounts were $39.3 million and $38.2 million as of December 31, 2016 and 2015, 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 as of December 31, 2016 and 2015.

Note 3. Property and Equipment

A summary of the unevaluated property costs excluded from oil and natural gas properties being amortized at December 31, 2016, and the year in which the costs were incurred follows:

	December 31, 2016				
	Costs Incurred During:				
In thousands	2016	2015	2014	2013 and Prior	Total
Property acquisition costs	$ 7,528	$ —	$ 4,875	$ 592,184	$ 604,587
Exploration and development	21,119	24,812	95,397	70,156	211,484
Capitalized interest	25,220	28,302	21,179	37,047	111,748
Total	$ 53,867	$ 53,114	$ 121,451	$ 699,387	$ 927,819

Our property acquisition costs for 2013 and prior were primarily related to the fair value allocated to the purchase of interests in the Cedar Creek Anticline ("CCA"), Hartzog Draw and Thompson fields, 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, 2016. The most significant development costs incurred during 2016, 2015 and 2014 relate to development in preparation for the CO_2 floods at Webster and Grieve fields, with the more significant development costs incurred during 2013 and prior relating to development in preparation for the CO_2 flood at Grieve Field. We have not yet recognized proved tertiary reserves in these fields.

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 the majority 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 4. Long-Term Debt

The following long-term debt and capital lease obligations were outstanding as of December 31, 2016 and 2015:

	December 31,	
In thousands	2016	2015
Senior Secured Bank Credit Agreement	$ 301,000	$ 175,000
9% Senior Secured Second Lien Notes due 2021	614,919	—
6⅜% Senior Subordinated Notes due 2021	215,144	400,000
5½% Senior Subordinated Notes due 2022	772,912	1,250,000
4⅝% Senior Subordinated Notes due 2023	622,297	1,200,000
Other Senior Subordinated Notes, including premium of $3 and $7, respectively	2,253	2,257
Pipeline financings	202,671	211,766
Capital lease obligations	48,718	71,324
Total debt principal balance	2,779,914	3,310,347
Future interest payable on 9% Senior Secured Second Lien Notes due 2021 (1)	228,825	—
Issuance costs on senior secured second lien and senior subordinated notes	(15,641)	(32,752)
Total debt, net of debt issuance costs	2,993,098	3,277,595
Less: current maturities of long-term debt (1)	(83,366)	(32,481)
Long-term debt and capital lease obligations	$ 2,909,732	$ 3,245,114

(1) Future interest payable on our 9% Senior Secured Second Lien Notes due 2021 (the "2021 Senior Secured Notes") represents most of the interest due over the term of this obligation, which has been accounted for as debt in accordance with FASC 470-60, *Troubled Debt Restructuring by Debtors*. Our current maturities of long-term debt as of December 31, 2016 include $50.3 million of future interest payable related to the 2021 Senior Secured Notes that is due within the next twelve months. See *2016 Senior Subordinated Notes Exchange* below for further discussion.

The ultimate parent company in our corporate structure, Denbury Resources Inc. ("DRI"), is the sole issuer of all of our outstanding 2021 Senior Secured Notes and 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, and the guarantees of the notes are full and unconditional and joint and several; any subsidiaries of DRI that are not subsidiary guarantors of such notes are minor subsidiaries.

Senior Secured Bank Credit Facility

In December 2014, we entered into an Amended and Restated Credit Agreement with JPMorgan Chase Bank, N.A., as administrative agent, and other lenders party thereto (the "Bank Credit Agreement"). The Bank Credit Agreement is a senior secured revolving credit facility with a maturity date of December 9, 2019. Under the Bank Credit Agreement, letters of credit are available in an aggregate amount not to exceed $100 million, which may be increased at the sole discretion of the administrative agent, and short-term swingline loans are available in an aggregate amount not to exceed $25 million, each subject to the available commitments under the Bank Credit Agreement. The Bank Credit Agreement is guaranteed jointly and severally by each subsidiary of DRI that is 100% owned, directly or indirectly, by DRI and is secured by (1) a significant portion of our proved oil and natural gas properties held through DRI's restricted subsidiaries; (2) the pledge of equity interests of such subsidiaries; (3) a pledge of commodity derivative agreements of DRI and such subsidiaries (as applicable); and (4) a pledge of deposit accounts, securities accounts and commodity accounts of DRI and such subsidiaries (as applicable). The Bank Credit Agreement limits our ability to, among other things, incur indebtedness; grant liens; engage in certain mergers, consolidations, liquidations and dissolutions; engage in sales of assets; make acquisitions and investments; make distributions and dividends; and enter into commodity derivative agreements, in each case subject to customary exceptions.

As of December 31, 2016, the borrowing base and lender commitments for the revolving credit facility were $1.05 billion, and scheduled redeterminations of the borrowing base are to occur semiannually, with the next such redetermination being scheduled for May 2017. If our outstanding debt under the Bank Credit Agreement were to ever exceed the borrowing base, we would be required to repay the excess amount over a period not to exceed six months.

In order to provide more flexibility in managing our balance sheet, the credit extended by our lenders, and continuing compliance with financial performance covenants in this low oil price environment, we entered into three amendments to the Bank Credit Agreement between May 2015 and April 2016 making the following modifications to the Bank Credit Agreement:

- for 2016 and 2017, the maximum permitted ratio of consolidated total net debt to consolidated EBITDAX covenant was suspended and replaced by a maximum permitted ratio of consolidated senior secured debt to consolidated EBITDAX covenant of 3.0 to 1.0 (only debt under our Bank Credit Agreement is considered consolidated senior secured debt for purposes of this ratio);
- for 2016 and 2017, a new covenant was added to require a minimum permitted ratio of consolidated EBITDAX to consolidated interest charges of 1.25 to 1.0;
- allowing for the incurrence of up to $1.0 billion of junior lien debt (subject to customary requirements), with $385.1 million of future incurrence available as of December 31, 2016;
- limiting unrestricted cash and cash equivalents to $225 million if more than $250 million of borrowings are outstanding under the Bank Credit Agreement; and
- limiting the amount spent on repurchases or other redemptions of our senior subordinated notes to $225 million, with up to $148.3 million of this capacity remaining available as of December 31, 2016.

Additionally, we are required to maintain a current ratio, as determined under the Bank Credit Agreement, of not less than 1.0 to 1.0.

Beginning in the first quarter of 2018, the ratio of consolidated total net debt to consolidated EBITDAX covenant will be reinstated, utilizing an annualized EBITDAX amount for the first, second, and third quarters of 2018 and building to a trailing four quarters by the end of 2018, with the maximum permitted ratios being 6.0 to 1.0 for the first quarter ending March 31, 2018, 5.5 to 1.0 for the second quarter ending June 30, 2018, and 5.0 to 1.0 for the third and fourth quarters ending September 30 and December 31, 2018, and returning to 4.25 to 1.0 for the first quarter ending March 31, 2019. As of December 31, 2016, (1) loans under the Bank Credit Agreement were subject to varying rates of interest based on either (a) for ABR Loans, a base rate determined under the Bank Credit Agreement (the "ABR") plus an applicable margin ranging from 1% to 2% per annum, or (b) for LIBOR Loans, the LIBOR rate plus an applicable margin ranging from 2% to 3% per annum (capitalized terms as defined in the Bank Credit Agreement) and (2) the undrawn portion of the aggregate lender commitments under the Bank Credit Agreement was subject to a commitment fee of 0.50%. As of December 31, 2016, we were in compliance with all debt covenants under the Bank Credit Agreement. The weighted average interest rate on borrowings outstanding under the Bank Credit Agreement was 3.0% and 2.3% as of December 31, 2016 and 2015, respectively.

The above description of our Bank Credit Agreement financial performance covenants and the changes provided for within the three amendments are qualified by the express language and defined terms contained in the Bank Credit Agreement, the First Amendment to the Bank Credit Agreement dated May 4, 2015, the Second Amendment to the Bank Credit Agreement dated February 17, 2016, and the Third Amendment to the Bank Credit Agreement dated April 18, 2016, each of which are filed as exhibits to our periodic reports filed with the SEC.

2016 Senior Subordinated Notes Exchange

During May 2016, we entered into privately negotiated agreements to exchange a total of $1,057.8 million of our existing senior subordinated notes for $614.9 million principal amount of our 2021 Senior Secured Notes plus 40.7 million shares of Denbury common stock, resulting in a net reduction from these exchanges of $442.9 million in our debt principal. The exchanged notes consisted of $175.1 million principal amount of our 6⅜% Senior Subordinated Notes due 2021 (the "2021 Notes"), $411.0 million principal amount of our 5½% Senior Subordinated Notes due 2022 (the "2022 Notes"), and $471.7 million principal amount of our 4⅝% Senior Subordinated Notes due 2023 (the "2023 Notes").

In accordance with FASC 470-60, the exchanges were accounted for as a troubled debt restructuring due to the level of concession provided by our senior subordinated note holders. Under this guidance, future interest applicable to the 2021 Senior Secured Notes is recorded as debt up to the point that the principal and future interest of the new notes is equal to the principal amount of the extinguished notes, rather than recognizing a gain on extinguishment for this amount. As a result, $254.7 million of future interest on the 2021 Senior Secured Notes was recorded as debt, which will be reduced as semiannual interest payments are made, with the remaining $22.8 million of future interest to be recognized as interest expense over the term of these notes. Therefore, future interest expense reflected in our Consolidated Statements of Operations on the 2021 Senior Secured Notes will be significantly lower than the actual cash interest payments. In addition, we recognized a gain of $12.0 million as a result of this debt exchange during the year ended December 31, 2016, which is included in "Loss (gain) on debt extinguishment" in the accompanying Consolidated Statements of Operations.

9% Senior Secured Second Lien Notes due 2021

In May 2016, we issued $614.9 million of 2021 Senior Secured Notes. The 2021 Senior Secured Notes, which bear interest at a rate of 9% per annum, were issued at par in connection with privately negotiated exchanges with a limited number of holders of $1,057.8 million of existing senior subordinated notes (see *2016 Senior Subordinated Notes Exchange* above). The 2021 Senior Secured Notes mature on May 15, 2021, and interest is payable semiannually in arrears on May 15 and November 15 of each year, beginning in November 2016. We may redeem the 2021 Senior Secured Notes in whole or in part at our option beginning December 15, 2018, at a redemption price of 109% of the principal amount, and at declining redemption prices thereafter, as specified in the indenture governing the 2021 Senior Secured Notes (the "Indenture"). Prior to December 15, 2018, we may at our option redeem up to an aggregate of 35% of the principal amount of the 2021 Senior Secured Notes at a price of 109% of par with the proceeds of certain equity offerings. In addition, at any time prior to December 15, 2018, we may redeem the 2021 Senior Secured Notes in whole or in part at a price equal to 100% of the principal amount plus a "make-whole" premium and accrued and unpaid interest. The 2021 Senior Secured Notes are not subject to any sinking fund requirements.

The Indenture contains customary covenants that restrict 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 limitations 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 (including existing senior subordinated notes)), provided that in certain circumstances we may make unlimited restricted payments so long as we maintain a ratio of total debt to EBITDA (as defined in the Indenture) not to exceed 2.5 to 1.0 (both before and after giving effect to any restricted payment).

The 2021 Senior Secured Notes are guaranteed jointly and severally by our subsidiaries representing substantially all of our assets, operations and income and are secured by second-priority liens on substantially all of the assets that secure the

Bank Credit Agreement, which second-priority liens are contractually subordinated to liens that secure our Bank Credit Agreement and any future additional priority lien debt.

Senior Subordinated Notes

6⅜% Senior Subordinated Notes due 2021. In February 2011, we issued $400 million of 2021 Notes. The 2021 Notes, which bear interest at a rate of 6.375% per annum, were sold at par. 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.

5½% Senior Subordinated Notes due 2022. In April 2014, we issued $1.25 billion of 2022 Notes. The 2022 Notes, which bear interest at a rate of 5.5% per annum, were sold at par. The net proceeds, after issuance costs, of $1.23 billion were used to repurchase or redeem our outstanding 8¼% Senior Subordinated Notes due 2020 (the "2020 Notes"), which were issued in 2010 (see *2014 Repurchase and Redemption of 8¼% Senior Subordinated Notes due 2020* below), and to pay down a portion of outstanding borrowings under our previous Bank Credit Agreement.

The 2022 Notes mature on May 1, 2022, and interest is payable on May 1 and November 1 of each year. We may redeem the 2022 Notes in whole or in part at our option beginning May 1, 2017, at a redemption price of 104.125% of the principal amount, and at declining redemption prices thereafter, as specified in the indenture. Prior to May 1, 2017, we may at our option redeem up to an aggregate of 35% of the principal amount of the 2022 Notes at a price of 105.5% of par with the proceeds of certain equity offerings. In addition, at any time prior to May 1, 2017, we may redeem 100% of the principal amount of the 2022 Notes at a price equal to 100% of the principal amounts plus a "make-whole" premium and accrued and unpaid interest. The 2022 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 bear interest at a rate of 4.625% per annum, were sold at par. The 2023 Notes mature on July 15, 2023, and interest is payable on January 15 and July 15 of each year. 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. 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. The 2023 Notes are not subject to any sinking fund requirements.

Restrictive Covenants in Indentures for Senior Subordinated Notes. Each of the indentures for the 2021 Notes, 2022 Notes and 2023 Notes contains certain covenants that are generally consistent and that 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 indentures for the 2022 and 2023 Notes (the "2022 and 2023 Indentures") 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 2022 and 2023 Indentures) not to exceed 2.5 to 1.0 (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 2022 and 2023 Indentures until the 2021 Notes have been redeemed or retired. As of December 31, 2016, we were in compliance with all debt covenants under the indentures related to our senior subordinated notes.

2016 Repurchases of Senior Subordinated Notes. During 2016, we repurchased a total of $181.9 million of our outstanding long-term indebtedness, consisting of $9.8 million principal amount of our 2021 Notes, $66.1 million principal amount of our 2022 Notes, and $106.0 million principal amount of our 2023 Notes in open-market transactions for a total purchase price of $76.7 million, excluding accrued interest. In connection with these series of transactions, we recognized a $103.1 million gain on extinguishment, net of unamortized debt issuance costs written off, during the year ended December 31,

2016. As of February 22, 2017, under the Bank Credit Agreement, up to an additional $148.3 million may be spent on repurchases or other redemptions of our senior subordinated notes.

2014 Repurchase and Redemption of 8¼% Senior Subordinated Notes due 2020. Pursuant to a cash tender, during 2014, we repurchased $996.3 million in principal of our 2020 Notes. We recognized a $113.9 million loss associated with the debt repurchases during the second quarter of 2014, which loss consists of both premium payments made to repurchase or redeem the 2020 Notes and the elimination of unamortized debt issuance costs related to these notes. The loss is included in our Consolidated Statements of Operations under the caption "Loss (gain) on debt extinguishment," and premium payments made to repurchase the notes are classified as a financing cash outflow on our Consolidated Statements of Cash Flows under the caption "Premium paid on repayment of senior subordinated notes."

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. These transactions are both accounted for 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 straight line or effective interest method over the term of each related facility or borrowing. Remaining unamortized debt issuance costs were $24.7 million and $49.8 million at December 31, 2016 and 2015, respectively. Issuance costs associated with our Bank Credit Agreement are included in "Other assets" in our Consolidated Balance Sheets, and issuance costs associated with our senior secured second lien and senior subordinated notes are included as a reduction of "Long-term debt, net of current portion" in our Consolidated Balance Sheets in accordance with the adoption of ASU 2015-03 (see Note 1, *Significant Accounting Policies – Recent Accounting Pronouncements – Recently Adopted – Debt Issuance Costs* above).

Indebtedness Repayment Schedule

At December 31, 2016, 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	
2017	$ 33,014
2018	33,966
2019	328,407
2020	16,145
2021	845,422
Thereafter	1,522,957
Total indebtedness	$ 2,779,911

Note 5. Income Taxes

Our income tax provision (benefit) is as follows:

	Year Ended December 31,		
In thousands	2016	2015	2014
Current income tax expense (benefit)			
Federal	$ —	$ (8,515)	$ (42,500)
State	(785)	160	(407)
Total current income tax benefit	(785)	(8,355)	(42,907)
Deferred income tax expense (benefit)			
Federal	(521,519)	(1,853,517)	400,544
State	(21,866)	(78,662)	29,429
Total deferred income tax expense (benefit)	(543,385)	(1,932,179)	429,973
Total income tax expense (benefit)	$ (544,170)	$ (1,940,534)	$ 387,066

At December 31, 2016, we had tax-effected federal net operating loss carryforwards ("NOLs") totaling $27.1 million, state NOLs totaling $42.6 million (before provision for valuation allowance), an estimated $51.1 million of enhanced oil recovery credits to carry forward related to our tertiary operations, an estimated $21.6 million of research and development credits, and $41.1 million of alternative minimum tax credits. Our state NOLs expire in various years, starting in 2019, although most do not begin to expire until 2036. Our enhanced oil recovery credits and research and development credits will begin to expire in 2023 and 2031, respectively.

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, 2016 and 2015 balance sheet dates. As of December 31, 2016, we had $36.5 million of deferred tax assets associated with State of Louisiana net operating losses. As the result of falling commodity prices, combined with a tax law enacted in the State of Louisiana effective June 30, 2015, which limits a company's utilization of certain deductions, including our net operating loss carryforwards, we recognized tax valuation allowances totaling $33.6 million during 2015 and an additional $2.9 million during 2016, which reduced the carrying value of our deferred tax assets. The valuation allowances will remain until the realization of future deferred tax benefits are more likely than not to become utilized.

As of December 31, 2016, we had an unrecognized tax benefit of $5.4 million related to an uncertain tax position. The unrecognized tax benefit was recorded during 2015 as a direct reduction of the associated deferred tax asset and, if recognized, would not materially affect our annual effective tax rate. The tax benefit from an uncertain tax position will only be recognized if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based upon the technical merits of the position. We currently do not expect a material change to the uncertain tax position within the next 12 months. Our policy is to recognize penalties and interest related to uncertain tax positions in income tax expense; however, no such amounts were accrued related to the uncertain tax position as of December 31, 2016.

In connection with the privately negotiated agreements to exchange a portion of our existing senior subordinated notes for 2021 Senior Secured Notes, we realized a tax gain due to the concession extended by our note holders during the second quarter of 2016. This tax gain was offset by net operating losses and other deferred tax asset attributes.

Significant components of our deferred tax assets and liabilities as of December 31, 2016 and 2015 are as follows:

	December 31,	
In thousands	2016	2015
Deferred tax assets		
Loss carryforwards – federal	$ 27,078	$ 52,580
Loss carryforwards – state	42,625	37,175
Tax credit carryover	41,132	34,837
Business credit carryforwards	72,748	70,452
Derivative contracts	27,261	—
Stock-based compensation	10,306	23,468
Unrecognized gain and original issue discount on debt exchange	106,321	—
Other	38,834	34,236
Valuation allowance	(36,510)	(33,600)
Total deferred tax assets	329,795	219,148
Deferred tax liabilities		
Property and equipment	(619,923)	(1,004,330)
Derivative contracts	—	(50,081)
Other	(3,750)	(16,826)
Total deferred tax liabilities	(623,673)	(1,071,237)
Total net deferred tax liability	$ (293,878)	$ (852,089)

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:

	Year Ended December 31,		
In thousands	2016	2015	2014
Income tax provision (benefit) calculated using the federal statutory income tax rate	$ (532,121)	$ (2,214,094)	$ 357,895
State income taxes, net of federal income tax benefit	(25,351)	(117,624)	25,368
Impairment of goodwill with no related tax basis	—	363,666	—
Tax shortfall on stock-based compensation deduction	9,557	—	—
Valuation allowance	2,910	33,600	—
Other	835	(6,082)	3,803
Total income tax expense (benefit)	$ (544,170)	$ (1,940,534)	$ 387,066

We file consolidated and separate income tax returns in the U.S. federal jurisdiction and in many state jurisdictions. The statutes of limitation for our income tax returns for tax years ending prior to 2011 have lapsed and therefore are not available for examination by respective taxing authorities. We have not paid any significant interest or penalties associated with our income taxes.

Note 6. Stockholders' Equity

401(k) Plan

We offer a 401(k) plan to which employees may contribute 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 2016, 2015 and 2014, our matching contributions to the 401(k) plan were approximately $7.7 million, $10.1 million and $9.9 million, respectively.

2015 Retirement of Treasury Stock

During the year ended December 31, 2015, we retired 60.0 million shares of existing treasury stock, with a carrying value of $884.1 million, acquired principally through our stock repurchase program. These retired shares are now included in the pool of authorized but unissued shares. Our accounting policy upon the retirement of treasury stock is to deduct its par value from common stock and reduce additional paid-in capital by the excess amount of treasury stock retired.

Dividends Declared During 2015

During the first three quarters of 2015, the Company's Board of Directors declared quarterly cash dividends of $0.0625 per common share, with dividends totaling $65.4 million paid to stockholders during the year ending December 31, 2015. In September 2015, in light of the continuing low oil price environment and our desire to maintain our financial strength and flexibility, the Company's Board of Directors suspended our quarterly cash dividend.

Note 7. Stock Compensation

The Amended and Restated 2004 Omnibus Stock and Incentive Plan, amended and restated as of May 24, 2016 (the "2004 Plan"), is an incentive plan that provides for the issuance of incentive and non-qualified stock options, restricted stock awards, restricted stock units, SARs settled in stock, and performance-based awards to officers, employees and directors. Since the 2004 Plan's inception, awards covering a total of 44.5 million shares of common stock have been authorized for issuance pursuant to the 2004 Plan. As of December 31, 2016, 9.7 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-based awards. Our incentive compensation program is administered by the Compensation Committee of our Board of Directors. The 2004 Plan was last approved by our stockholders in May 2016 and will expire in May 2026.

Stock-based compensation expense associated with our field employees is included in "Lease operating expenses," 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. Effective January 1, 2016, with the adoption of ASU 2016-09, we made an accounting policy election to account for forfeitures as they occur, versus the previously-estimated forfeiture rate.

Stock-based compensation costs for the years ended December 31, 2016, 2015 and 2014, are as follows:

	Year Ended December 31,		
In thousands	2016	2015	2014
Stock-based compensation expensed			
General and administrative expenses	$ 14,359	$ 27,995	$ 27,789
Lease operating expenses	636	2,609	2,724
Total stock-based compensation expensed	14,995	30,604	30,513
Stock-based compensation capitalized	6,047	8,681	9,019
Total cost of stock-based compensation arrangements	$ 21,042	$ 39,285	$ 39,532
Income tax benefit recognized for stock-based compensation arrangements	$ 5,698	$ 11,630	$ 11,595

Stock Options and SARs

Prior to January 1, 2006, we granted incentive and non-qualified stock options to our employees. Effective January 1, 2006, we 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. As of December 31, 2015, we also discontinued the issuance of SARs.

The stock options and SARs generally become exercisable over a three-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 award, or one year after the death of the optionee. As of December 31, 2015, all outstanding options had expired. The stock options and SARs were granted with a strike price equal to the fair market value at the time of grant, which is generally defined as the closing price on the NYSE on the date of grant.

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 SAR is based on the U.S. Treasury yield curve in effect at the time of grant. The expected life of SARs granted was derived from examination of our historical SAR 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. There were no SAR awards granted in 2016.

	Year Ended December 31,	
	2015	2014
Weighted average fair value of SARs granted	$ 1.77	$ 3.55
Risk-free interest rate	1.29%	1.31%
Expected life	4.0 years	3.8 to 4.0 years
Expected volatility	39.4%	38.0%
Dividend yield	3.42%	3.10%

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, 2015	8,903,514	$ 13.76		
Granted	—	—		
Exercised	—	—		
Forfeited	(365,410)	8.21		
Expired	(2,597,360)	14.98		
Outstanding at December 31, 2016	5,940,744	13.57	3.0	$ —
Exercisable at end of period	4,198,913	$ 15.99	2.1	$ —

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	2016	2015	2014
Intrinsic value of stock options and SARs exercised	$ —	$ 60	$ 7,985
Grant-date fair value of stock options and SARs vested	4,787	6,534	9,998

As of December 31, 2016, there was $1.5 million of total compensation cost to be recognized in future periods related to nonvested share-based SAR compensation arrangements. The cost is expected to be recognized over a weighted-average period of 1.0 year. 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	2016	2015	2014
Cash received from stock option exercises	$ —	$ 562	$ 7,022
Tax benefit realized for the exercises of stock options and SARs	—	—	212

Restricted Stock

We grant non-performance-based restricted stock to new employees during the year as part of their new hire compensation packages, and annually we grant restricted stock awards to employees and directors as part of our long-term compensation program. Holders of non-performance-based restricted stock awards have the rights of owning non-restricted stock (including voting rights) except that the holders are not entitled to delivery of a portion thereof until certain requirements are met. Beginning in 2014, non-performance-based restricted stock awards provide the holders with forfeitable dividend equivalent rights which vests with the underlying shares. Non-performance-based restricted stock vests over a three-year vesting period, with the specific terms of vesting determined at the time of grant.

As of December 31, 2016, there was $26.1 million of unrecognized compensation expense related to nonvested non-performance-based 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 non-performance-based restricted stock:

	Year Ended December 31,		
In thousands	2016	2015	2014
Fair value of restricted stock vested	$ 6,161	$ 12,549	$ 24,780

A summary of the status of our nonvested non-performance-based restricted stock grants issued, and the changes during the year ended December 31, 2016, is presented below:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at December 31, 2015	5,589,687	$ 9.27
Granted	7,569,553	3.23
Vested	(2,906,465)	10.44
Forfeited	(511,990)	7.09
Nonvested at December 31, 2016	9,740,785	4.34

Performance-Based Equity Awards

Annually, the Compensation Committee of the Board of Directors grants performance-based equity awards to Denbury's officers. 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: (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 target number of shares will be earned if the maximum target levels are met (200% of target vesting levels). With respect to the 2016 performance-based equity awards, any amounts earned above the 100% target levels will be payable in cash, rather than in shares of Denbury stock, in order to conserve available shares under the Plan. If performance is below the designated minimum levels, 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.

During 2016 and 2015, we granted performance-based equity awards to our officers. As of December 31, 2016, there was $2.2 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 (presented at the target level) are as follows:

	Year Ended December 31,		
	2016	2015	2014
Weighted average fair value of Performance-Based TSR Awards granted	$ 1.78	$ 7.59	$ 19.81
Risk-free interest rate	1.31%	0.96%	0.80%
Expected life	3.0 years	3.0 years	3.0 years
Expected volatility	57.2%	33.6%	39.4%
Dividend yield	—%	3.42%	2.50%

A summary of the status of the nonvested performance-based equity awards (presented at the target level) during the year ended December 31, 2016, 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, 2015	559,260	$ 13.82	768,555	$ 14.75
Granted [(1)]	596,445	2.17	1,491,112	1.78
Vested [(2)]	(139,049)	7.31	(145,731)	20.08
Forfeited	(52,221)	5.58	(97,513)	4.94
Nonvested at December 31, 2016	964,435	8.00	2,016,423	5.25

(1) Amounts granted reflect the number of performance units granted. The actual payout of the shares may be between 0% and 200%, with any amounts earned above the 100% target levels payable in cash, rather than in shares of Denbury stock, in order to conserve available shares under the Plan.
(2) During 2016, the service period lapsed on these performance unit awards. The lapsed units earned a weighted average of 0% and 25% of target for each vested Operational and TSR performance-based award, respectively, representing 36,434 aggregate shares of common stock issued.

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

	Year Ended December 31,		
In thousands	2016	2015	2014
Vesting date fair value of Performance-Based Operational Awards	$ —	$ 2,861	$ —
Vesting date fair value of Performance-Based TSR Awards	81	300	—

Note 8. 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 settlements of expired contracts, are shown under "Commodity derivatives expense (income)" in our Consolidated Statements of Operations.

Historically, we have entered 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 and to provide more certainty to our future cash flows. We do not hold or issue derivative financial instruments for trading purposes. Generally, these contracts have consisted of various combinations of price floors, collars, three-way collars, fixed-price swaps and fixed-price swaps enhanced with a sold put. The production that we hedge has varied from year to year depending on our levels of debt, financial strength and expectation of future commodity prices.

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 (or affiliates of such lenders). As of December 31, 2016, 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 as of December 31, 2016, none of which are classified as hedging instruments in accordance with the FASC *Derivatives and Hedging* topic:

			Contract Prices ($/Bbl)					
				Weighted Average Price				
Months	Index Price	Volume (Barrels per day)	Range [(1)]	Swap	Sold Put	Floor	Ceiling
Oil Contracts:							
2017 Fixed-Price Swaps							
Jan – Mar	NYMEX	22,000	$ 41.15 – 45.45	$ 42.67	$ —	$ —	$ —
Jan – Mar	LLS	10,000	42.35 – 46.15	43.77	—	—	—
Apr – June	NYMEX	22,000	41.20 – 46.50	43.99	—	—	—
Apr – June	LLS	7,000	42.65 – 46.65	45.35	—	—	—
2017 Collars							
Jan – Mar	NYMEX	4,000	$ 40.00 – 55.40	$ —	$ —	$ 40.00	$ 54.80
Jan – Mar	LLS	3,000	40.00 – 57.35	—	—	40.00	57.23
Oct – Dec	NYMEX	1,000	40.00 – 70.00	—	—	40.00	70.00
2017 Three-Way Collars [(2)]							
July – Sept	NYMEX	13,500	$ 40.00 – 70.25	$ —	$ 30.00	$ 40.00	$ 69.13
July – Sept	LLS	2,000	41.00 – 69.25	—	31.00	41.00	69.25
Oct – Dec	NYMEX	10,000	40.00 – 70.20	—	30.00	40.00	69.64
Oct – Dec	LLS	1,000	41.00 – 70.25	—	31.00	41.00	70.25

(1) Ranges presented for fixed-price swaps represent the lowest and highest fixed prices of all open contracts for the period presented. For collars and three-way collars, ranges represent the lowest floor price and highest ceiling price for all open contracts for the period presented.

(2) A three-way collar is a costless collar contract combined with a sold put feature (at a lower price) with the same counterparty. The value received for the sold put is used to enhance the contracted floor and ceiling price of the related collar. At the contract settlement date, (1) if the index price is higher than the ceiling price, we pay the counterparty the difference between the index price and ceiling price for the contracted volumes, (2) if the index price is between the floor and ceiling price, no settlements occur, (3) if the index price is lower than the floor price but at or above the sold put price, the counterparty pays us the difference between the index price and the floor price for the contracted volumes and (4) if the index price is lower than the sold put price, the counterparty pays us the difference between the floor price and the sold put price for the contracted volumes.

Note 9. Fair Value Measurements

The FASC *Fair Value Measurement* 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"). 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 income 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 derivatives that are based on NYMEX pricing and fixed-price swaps that are based on regional pricing other than NYMEX (e.g., Light Louisiana Sweet). Our costless collars and the sold put features of our three-way 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, 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. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. At December 31, 2016, instruments in this category include non-exchange-traded costless collars and three-way collars that are based on regional pricing other than NYMEX (e.g., Light Louisiana Sweet). The valuation models utilized for costless collars and three-way collars are consistent with the methodologies described above; however, the implied volatilities utilized in the valuation of Level 3 instruments are developed using a benchmark, which is considered a significant unobservable input. An increase or decrease of 100 basis points in the implied volatility inputs utilized in our fair value measurement would result in a change of approximately $50 thousand in the fair value of these instruments as of December 31, 2016.

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, 2016 and 2015:

	Fair Value Measurements Using:			
In thousands	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
December 31, 2016				
Liabilities				
Oil derivative contracts – current	$ —	$ 68,753	$ 526	$ 69,279
Total Liabilities	$ —	$ 68,753	$ 526	$ 69,279
December 31, 2015				
Assets				
Oil derivative contracts – current	$ —	$ 90,012	$ 52,834	$ 142,846
Total Assets	$ —	$ 90,012	$ 52,834	$ 142,846

Since we do not apply 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.

Level 3 Fair Value Measurements

The following table summarizes the changes in the fair value of our Level 3 assets and liabilities for the years ended December 31, 2016 and 2015:

	Year Ended December 31,	
In thousands	2016	2015
Fair value of Level 3 instruments, beginning of year	$ 52,834	$ 188,446
Fair value adjustments on commodity derivatives	(2,135)	43,378
Receipt on settlements of commodity derivatives	(51,225)	(178,990)
Fair value of Level 3 instruments, end of year	$ (526)	$ 52,834
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets or liabilities still held at the reporting date	$ (526)	$ 21,509

We utilize an income approach to value our Level 3 costless collars and three-way collars. 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. The following table details fair value inputs related to implied volatilities utilized in the valuation of our Level 3 oil derivative contracts:

	Fair Value at 12/31/2016 (in thousands)	Valuation Technique	Unobservable Input	Range
Oil derivative contracts	$ (526)	Discounted cash flow / Black-Scholes	Volatility of Light Louisiana Sweet for settlement periods beginning after December 31, 2016	15.3% – 38.4%

Other Fair Value Measurements

The carrying value of our loans under our Bank Credit Agreement approximate fair value, as they are subject to short-term floating interest rates that approximate the rates available to us for those periods. We use a market approach to determine the fair value of our fixed-rate long-term debt using observable market data. The fair values of our senior secured second lien notes and senior subordinated notes are based on quoted market prices. The estimated fair value of the principal amount of our debt as of December 31, 2016 and 2015, excluding pipeline financing and capital lease obligations, was $2,327.8 million and $1,119.0 million, respectively, which increase is primarily driven by an increase in quoted market prices. 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 10. 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 9 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 sublease rentals received during the periods indicated:

	Year Ended December 31,		
In thousands	2016	2015	2014
Operating lease payments	$ 22,744	$ 29,403	$ 43,333
Sublease rental receipts	3,074	3,698	2,347

The following tables summarize by year the remaining non-cancelable future payments under our leases as of December 31, 2016:

In thousands	Pipeline and Capital Leases
2017	$ 48,579
2018	48,139
2019	40,215
2020	27,872
2021	26,092
Thereafter	165,170
Total minimum lease payments	356,067
Less: Amount representing interest	(104,678)
Present value of minimum lease payments	$ 251,389

In thousands	Operating Leases
2017	$ 10,965
2018	11,154
2019	10,574
2020	9,734
2021	9,996
Thereafter	38,549
Total minimum lease payments	$ 90,972

In addition, we expect to receive approximately $7.8 million for 2017 through 2019 under our sublease agreements.

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 16 years. The price we will pay for CO_2 generally varies depending on the amount of CO_2 delivered and the price of oil. Once all commitments have commenced, our annual commitment under these contracts could range from $41 million to $86 million per year, assuming a $60 per Bbl NYMEX oil price.

In the second quarter of 2016, we amended our CO_2 offtake agreement with Mississippi Power Company ("MSPC"), which amendment included increasing our offtake percentage from 70% to 100% of CO_2 quantities produced and lowering the base price related to the cost of CO_2, deliveries of which are currently expected to begin during the first half of 2017. Based on the amended terms in the agreement, we concluded for accounting purposes that the agreement contains an embedded lease related to the pipeline owned by MSPC used to transport CO_2 to Denbury. We currently plan to record a capital lease on the balance sheet of approximately $110 million upon lease commencement.

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 one CO_2 volumetric production payment ("VPP"). Based upon the maximum amounts deliverable as stated in the industrial contracts and the VPP, we estimate that we may be obligated to deliver up to 383 Bcf of CO_2 to these customers over the next 12 years. The maximum volume required in any given year is approximately 111 MMcf/d, which we judge to be minor given the size of our Jackson Dome proved CO_2 reserves at December 31, 2016, our current production capabilities and our projected levels of CO_2 usage for our own tertiary flooding program.

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, results of operations or cash flows, litigation is subject to inherent uncertainties. Although a single or multiple adverse rulings or settlements could possibly have a material adverse effect on our finances, we only accrue for losses from litigation and claims if we determine that a loss is probable and the amount can be reasonably estimated.

Riley Ridge Helium Supply Contract Claim

As part of our 2010 and 2011 acquisitions of the Riley Ridge Unit and associated gas processing facility that was under construction, we assumed a 20-year helium supply contract under which we agreed to supply to a third-party purchaser the helium separated from the full well stream by operation of the gas processing facility. The helium supply contract provides for the delivery of a minimum contracted quantity of helium, subject to adjustment after startup of the Riley Ridge gas processing facility, with liquidated damages payable if specified quantities of helium are not supplied in accordance with the terms of the contract. The liquidated damages are capped at $8.0 million per contract year and are capped at an aggregate of $46.0 million over the remaining term of the contract. As the gas processing facility has been shut-in since mid-2014, we have not been able to supply helium to the third-party purchaser under the helium supply contract. In a case originally filed in November 2014 by APMTG Helium, LLC, the third-party helium purchaser, after a week of trial on the third-party purchaser's claim for multiple years of liquidated damages for non-delivery of volumes of helium specified under the helium supply contract, and on our claim that the contractual obligation is excused by virtue of events that fall within the force majeure provisions in the helium supply contract, the trial was stayed in late February 2017 until a later date yet to be determined by the District Court. The Company plans to continue to vigorously defend its position, but we are unable to predict at this time the outcome of this dispute.

Settlement of NGS Sub Corp., Evolution, et al v. Denbury Onshore, LLC

During the second quarter of 2016, we settled litigation pending since 2013 related to interpretation of the terms of the contracts under which we purchased our interest in the Delhi Field from an affiliate of the entity which continues to own an interest in the field, and claims related to the ongoing financial and operating impact of the June 2013 release of well fluids in that field and our remediation of that release. In the settlement, we paid the co-owner $27.5 million, exchanged various interests in the field, and agreed upon ongoing field operations and related transportation charges. The cash payment was recorded to "Other expenses" in our Consolidated Statements of Operations in the second quarter of 2016.

Other Contingencies

We are subject to audits for various taxes (income, sales and use, and severance) in the various states in which we operate, 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 11. Additional Balance Sheet Details

Trade and Other Receivables, Net

	December 31,	
In thousands	2016	2015
Trade accounts receivable, net	$ 20,084	$ 40,146
Commodity derivatives settlement receivables	—	25,994
Other receivables	23,816	20,953
Total	$ 43,900	$ 87,093

Accounts Payable and Accrued Liabilities

	December 31,	
In thousands	2016	2015
Accrued compensation	$ 41,894	$ 46,780
Accrued lease operating expenses	28,918	37,549
Accrued interest	28,823	48,908
Accounts payable	28,301	30,477
Taxes payable	20,979	32,438
Accrued exploration and development costs	7,420	20,892
Other	43,931	36,153
Total	$ 200,266	$ 253,197

Note 12. Supplemental Cash Flow Information

Supplemental Cash Flow Information

	Year Ended December 31,		
In thousands	2016	2015	2014
Supplemental cash flow information			
Cash paid for interest, expensed	$ 130,843	$ 146,560	$ 185,140
Cash paid for interest, capitalized	25,982	32,146	24,202
Cash paid for interest, treated as a reduction of debt	25,835	—	—
Cash paid for income taxes	375	6,340	5,033
Cash received from income tax refunds	(2,455)	(50,163)	(13,193)
Noncash investing and financing activities			
Increase in asset retirement obligations	11,621	14,866	6,500
Increase (decrease) in liabilities for capital expenditures	(13,593)	(97,278)	215
Retirement of treasury stock	—	884,129	—

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 reserves, 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 $25.2 million, $28.3 million and $21.8 million during the years ended December 31, 2016, 2015 and 2014, respectively. 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 $3.9 million, $5.5 million and $4.9 million during the years ended December 31, 2016, 2015 and 2014, respectively. See Note 2, *Asset Retirement Obligations*, for additional information.

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

	Year Ended December 31,		
In thousands	2016	2015	2014
Property acquisitions			
Proved	$ 4,867	$ 28,224	$ 3,801
Unevaluated	8,771	—	8,028
Exploration	176	720	5,493
Development	251,597	407,021	964,726
Total costs incurred (1)	$ 265,411	$ 435,965	$ 982,048

(1) Capitalized general and administrative costs that directly relate to exploration and development activities were $48.4 million, $62.3 million and $62.2 million for the years ended December 31, 2016, 2015 and 2014, 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	2016	2015	2014
Oil, natural gas, and related product sales	$ 935,751	$ 1,213,026	$ 2,372,473
Lease operating expenses	414,937	515,043	647,559
Marketing expenses, net of third-party purchases, and plant operating expenses	45,151	48,319	47,965
Production and ad valorem taxes	68,878	95,687	155,495
Depletion, depreciation, and amortization	169,550	436,167	494,402
CO_2 properties and pipelines depletion and depreciation (1)	50,573	55,929	58,759
Write-down of oil and natural gas properties	810,921	4,939,600	—
Commodity derivatives expense (income)	127,944	(147,999)	(555,255)
Net operating income (loss)	(752,203)	(4,729,720)	1,523,548
Income tax provision (benefit)	(285,837)	(1,797,294)	578,948
Results of operations from oil and natural gas producing activities	$ (466,366)	$ (2,932,426)	$ 944,600
Depletion, depreciation, and amortization per BOE	$ 9.40	$ 18.50	$ 20.36

(1) Represents an allocation of the depletion and depreciation 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 as of December 31, 2016.

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 2016, 2015 and 2014 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,								
	2016			2015			2014		
	Oil (MBbl)	Gas (MMcf)	Total (MBOE)	Oil (MBbl)	Gas (MMcf)	Total (MBOE)	Oil (MBbl)	Gas (MMcf)	Total (MBOE)
Balance at beginning of year	282,250	38,305	288,634	362,335	452,402	437,735	386,659	489,954	468,318
Revisions of previous estimates	(9,302)	16,289	(6,587)	(56,582)	(406,124)	(124,269)	161	(29,007)	(4,673)
Improved recovery (1)	—	—	—	357	—	357	1,468	—	1,468
Production	(22,487)	(5,628)	(23,425)	(25,245)	(8,093)	(26,594)	(25,771)	(8,379)	(27,168)
Acquisition of minerals in place	36	—	36	1,385	120	1,405	—	—	—
Sales of minerals in place	(3,394)	(4,651)	(4,169)	—	—	—	(182)	(166)	(210)
Balance at end of year	247,103	44,315	254,489	282,250	38,305	288,634	362,335	452,402	437,735
Proved Developed Reserves – end of year	201,919	43,955	209,245	223,060	37,951	229,385	269,377	416,421	338,780
Proved Undeveloped Reserves – end of year	45,184	360	45,244	59,190	354	59,249	92,958	35,981	98,955

(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.

Revision of previous estimates during 2015 reflect the significant decline in commodity prices between December 31, 2014 and 2015, whereby the average first-day-of-the-month NYMEX oil price used in estimating our proved reserves declined from $94.99 per Bbl at December 31, 2014, to $50.28 per Bbl at December 31, 2015, and for natural gas declined from $4.30 per MMBtu at December 31, 2014, to $2.63 per MMBtu at December 31, 2015. These revisions include the elimination of approximately 368 Bcf (61 MMBOE) of proved natural gas reserves at Riley Ridge during 2015, which reserves were reclassified and are no longer considered proved reserves primarily as a result of the decline in average first-day-of-the-month natural gas prices utilized in preparing our December 31, 2015 reserve report.

There were no significant additions to our oil and natural gas reserves in 2016, 2015 or 2014, as the magnitude of proved reserves that we can book in any given year depends on our progress with new floods and the timing of the production response, and we initiated no new floods in 2016, 2015 or 2014.

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 to calculate 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,		
	2016	2015	2014
Oil (NYMEX price per Bbl)	$ 42.75	$ 50.28	$ 94.99
Natural Gas (Henry Hub price per MMBtu)	2.55	2.63	4.30

The decreases in the Standardized Measure of discounted future net cash flows during 2015 and 2016 in the tables that follow were significantly impacted by the decline in first-day-of-the-month average NYMEX oil prices between 2014 and 2016. The weighted-average oil prices we receive relative to NYMEX oil prices (our NYMEX oil price differential) utilized were \$3.39 per Bbl below representative NYMEX oil prices as of December 31, 2016, compared to \$2.17 per Bbl below representative NYMEX oil prices as of December 31, 2015, and \$3.10 per Bbl below representative NYMEX oil prices as of December 31, 2014.

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	2016	2015	2014
Future cash inflows	$ 9,747,726	$ 13,413,758	$ 34,761,067
Future production costs	(5,743,198)	(7,649,757)	(14,563,782)
Future development costs	(1,595,871)	(1,712,693)	(2,319,727)
Future income taxes	(258,047)	(657,560)	(5,711,897)
Future net cash flows	2,150,610	3,393,748	12,165,661
10% annual discount for estimated timing of cash flows	(751,393)	(1,503,624)	(6,257,533)
Standardized measure of discounted future net cash flows	$ 1,399,217	$ 1,890,124	$ 5,908,128

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	2016	2015	2014
Beginning of year	$ 1,890,124	$ 5,908,128	$ 7,128,744
Sales of oil and natural gas produced, net of production costs	(406,782)	(553,978)	(1,521,529)
Net changes in prices and production costs	(784,010)	(7,341,451)	(1,415,154)
Improved recovery (1)	—	6,299	51,793
Previously estimated development costs incurred	86,012	172,146	472,154
Change in future development costs	85,797	(206,194)	(289,622)
Revisions due to timing and other	48,697	660,335	(205,912)
Accretion of discount	209,608	806,630	1,020,008
Acquisition of minerals in place	477	26,698	—
Sales of minerals in place	(16,671)	—	2,549
Net change in income taxes	285,965	2,411,511	665,097
End of year	$ 1,399,217	$ 1,890,124	$ 5,908,128

(1) 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 DISCLOSURES (UNAUDITED)

Based on engineering reports prepared by DeGolyer and MacNaughton, proved CO_2 reserves were estimated as follows:

	Year Ended December 31,		
In MMcf	2016	2015	2014
CO_2 reserves			
Gulf Coast region (1)	5,332,576	5,501,175	5,697,642
Rocky Mountain region (2)	1,214,428	1,237,603	3,035,286

(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 (8/8ths) basis, of which our net revenue interest was approximately 4.2 Tcf, 4.4 Tcf and 4.5 Tcf at December 31, 2016, 2015 and 2014, respectively, and include reserves dedicated to volumetric production payments of 12.3 Bcf, 25.3 Bcf and 9.3 Bcf at December 31, 2016, 2015 and 2014, respectively.

(2) Proved CO_2 reserves in the Rocky Mountain region consist of our reserves at Riley Ridge (presented on a gross (8/8ths) basis) and our overriding royalty interest in LaBarge Field, of which our net revenue interest was approximately 1.2 Tcf, 1.2 Tcf and 2.6 Tcf at December 31, 2016, 2015 and 2014, respectively. As of December 31, 2015, Riley Ridge CO_2 and helium reserves were reclassified and are no longer considered proved reserves primarily as a result of the decline in average first-day-of-the-month natural gas prices utilized in preparing our December 31, 2015 reserve report.

Denbury Resources Inc.
Unaudited Supplementary Information

UNAUDITED QUARTERLY INFORMATION

In thousands, except per-share data	March 31	June 30	September 30	December 31
2016				
Revenues and other income	$ 194,844	$ 255,148	$ 253,985	$ 271,619
Commodity derivatives expense (income)	22,826	98,209	(21,224)	28,133
Gain on debt extinguishment	(94,991)	(12,278)	(7,826)	—
Write-down of oil and natural gas properties	256,000	479,400	75,521	—
Other expenses (1)	291,322	293,425	246,669	840,757
Net loss	(185,193)	(380,668)	(24,590)	(385,726)
Net loss per common share:				
Basic	(0.53)	(1.03)	(0.06)	(0.99)
Diluted	(0.53)	(1.03)	(0.06)	(0.99)
Cash flow provided by operating activities	2,029	60,915	96,415	59,864
Cash flow used in investing activities	(66,954)	(60,566)	(6,487)	(71,410)
Cash flow provided by (used in) financing activities	70,365	(6,056)	(89,200)	9,879
2015				
Revenues and other income	$ 307,649	$ 376,694	$ 303,600	$ 269,617
Commodity derivatives expense (income)	(83,076)	48,926	(92,028)	(21,821)
Write-down of oil and natural gas properties	146,200	1,705,800	1,760,600	1,327,000
Impairment of goodwill	—	—	1,261,512	—
Other expenses (1)	416,732	406,635	348,522	358,540
Net loss	(107,746)	(1,148,499)	(2,244,126)	(885,077)
Net loss per common share:				
Basic	(0.31)	(3.28)	(6.41)	(2.56)
Diluted	(0.31)	(3.28)	(6.41)	(2.56)
Dividends declared per common share (2)	0.0625	0.0625	0.0625	—
Cash flow provided by operating activities	137,764	288,957	272,676	164,907
Cash flow used in investing activities	(192,578)	(143,934)	(91,028)	(122,645)
Cash flow provided by (used in) financing activities	37,682	(146,631)	(173,849)	(51,662)

(1) Includes a $591.0 million accelerated depreciation charge associated with the Riley Ridge gas processing facility and related assets during the three months ended December 31, 2016, $27.5 million related to the settlement agreement with Evolution during the three months ended June 30, 2016 and ($13.7 million) related to Delhi remediation charges, net of insurance and other reimbursements during the three months ended September 30, 2015.

(2) On September 21, 2015, in light of the continuing low oil price environment and our desire to maintain our financial strength and flexibility, the Company's Board of Directors suspended our quarterly cash dividend effective after payment of our third quarter dividend on September 29, 2015.

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, 2016, 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 2016, 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" (2013) 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, 2016, 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.

PART III

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 2016 Annual Meeting of Shareholders to be held May 24, 2017 ("Annual Meeting"), and is incorporated herein by reference.

Code of Ethics

We have adopted a Code of Ethics for Senior Financial Officers. 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.

Denbury Resources Inc.

PART IV

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 66. 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
3(a)	Second Restated Certificate of Incorporation of Denbury Resources Inc. filed with the Delaware Secretary of State on October 30, 2014 (incorporated by reference to Exhibit 3(a) of Form 10-Q filed by the Company on November 7, 2014, File No. 001-12935).
3(b)	Second Amended and Restated Bylaws of Denbury Resources Inc. as of November 4, 2014 (incorporated by reference to Exhibit 3(b) of Form 10-Q filed by the Company on November 7, 2014, File No. 001-12935).
4(a)	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(b)	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(c)	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(d)	Indenture for 6⅜% 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(e)	First Supplemental Indenture for 6⅜% Senior Subordinated Notes due 2021, dated as of December 31, 2014, 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 February 27, 2015, File No. 001-12935).
4(f)	Indenture for 4⅝% 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).
4(g)	First Supplemental Indenture for 4⅝% Senior Subordinated Notes due 2023, dated as of December 31, 2014, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4(z) of Form 10-K filed by the Company on February 27, 2015, File No. 001-12935).
4(h)	Indenture for 5½% Senior Subordinated Notes due 2022, dated as of April 30, 2014, 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 May 1, 2014, File No. 001-12935).

Exhibit No.	Exhibit
4(i)	First Supplemental Indenture for 5½% Senior Subordinated Notes due 2022, dated as of December 31, 2014, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4(bb) of Form 10-K filed by the Company on February 27, 2015, File No. 001-12935).
4(j)	Indenture for 9% Senior Secured Second Lien Notes due 2021, dated as of May 10, 2016, by and among Denbury Resources Inc., certain of its subsidiaries, and Wilmington Trust, National Association, as Trustee and Collateral Trustee (incorporated by reference to Exhibit 4.1 of Form 8-K filed by the Company on May 11, 2016, File No. 001-12935).
10(a)	Amended and Restated Credit Agreement, dated as of December 9, 2014, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lending institutions party thereto (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on December 15, 2014, File No. 001-12935).
10(b)	First Amendment to Amended and Restated Credit Agreement, dated as of May 4, 2015, 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 May 6, 2015, File No. 001-12935).
10(c)	Second Amendment to Amended and Restated Credit Agreement, dated as of February 17, 2016, 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 February 23, 2016, File No. 001-12935).
10(d)	Third Amendment to Amended and Restated Credit Agreement, dated as of April 18, 2016, 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 April 20, 2016, File No. 001-12935).
10(e)	Collateral Trust Agreement, dated as of May 10, 2016, by and among Denbury Resources Inc., certain of its subsidiaries, and Wilmington Trust, National Association, as Trustee and Collateral Trustee (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on May 11, 2016, File No. 001-12935).
10(f)	Intercreditor Agreement, dated as of May 10, 2016, by and between JPMorgan Chase Bank, N.A., as Priority Lien Agent, and Wilmington Trust, National Association, as Collateral Trustee (incorporated by reference to Exhibit 10.2 of Form 8-K filed by the Company on May 11, 2016, File No. 001-12935).
10(g)	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(h)	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(i)**	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(j)**	Denbury Resources Inc. Director Deferred Compensation Plan, as amended and restated effective as of December 16, 2015 (incorporated by reference to Exhibit 10(i) of Form 10-K filed by the Company on February 26, 2016, File No. 001-12935).

Exhibit No.	Exhibit
10(k)**	Denbury Resources Inc. Severance Protection Plan, as amended and restated effective as of March 31, 2016 (incorporated by reference to Exhibit 10(f) of Form 10-Q filed by the Company on May 6, 2016, File No. 001-12935).
10(l)**	Denbury Resources Inc. 2004 Omnibus Stock and Incentive Plan, as amended and restated effective as of May 24, 2016 (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on May 27, 2016, File No. 001-12935).
10(m)**	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(n)**	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(o)**	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(p)**	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(q)**	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(r)**	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).
10(s)**	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(t)**	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(u)**	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(v)**	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(w)**	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(x)**	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).
10(y)**	2014 Form of Performance Cash Award under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(a) of Form 10-Q filed by the Company on May 12, 2014, File No. 001-12935).

Exhibit No.	Exhibit
10(z)**	2014 Form of TSR Performance Award under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(b) of Form 10-Q filed by the Company on May 12, 2014, File No. 001-12935).
10(aa)**	2014 Form of Performance Capital Efficiency Share Award under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(c) of Form 10-Q filed by the Company on May 12, 2014, File No. 001-12935).
10(bb)**	2014 Form of Growth and Income Performance Share Award under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(d) of Form 10-Q filed by the Company on May 12, 2014, File No. 001-12935).
10(cc)**	2014 Form of Restricted Share Award Cliff Vesting Awards under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(e) of Form 10-Q filed by the Company on May 12, 2014, File No. 001-12935).
10(dd)**	2015 Form of Restricted Share Award to officers under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(d) of Form 10-Q filed by the Company on May 6, 2015, File No. 001-12935).
10(ee)**	2015 Form of TSR Performance Award under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(e) of Form 10-Q filed by the Company on May 6, 2015, File No. 001-12935).
10(ff)**	2015 Form of TSR Performance Award for Phil Rykhoek under 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 6, 2015, File No. 001-12935).
10(gg)**	2015 Form of Capital Efficiency Performance Share Award under 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 6, 2015, File No. 001-12935).
10(hh)**	2015 Form of Capital Efficiency Performance Share Award for Phil Rykhoek under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(h) of Form 10-Q filed by the Company on May 6, 2015, File No. 001-12935).
10(ii)**	2015 Form of Growth and Income Performance Share Award under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(i) of Form 10-Q filed by the Company on May 6, 2015, File No. 001-12935).
10(jj)**	2015 Form of Growth and Income Performance Share Award for Phil Rykhoek under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(j) of Form 10-Q filed by the Company on May 6, 2015, File No. 001-12935).
10(kk)**	2016 Form of TSR Performance Award-Equity under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(a) of Form 10-Q filed by the Company on May 6, 2016, File No. 001-12935).
10(ll)**	2016 Form of TSR Performance Award-Cash under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(b) of Form 10-Q filed by the Company on May 6, 2016, File No. 001-12935).
10(mm)* **	2016 Form of EBITDAX Performance Award-Equity under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.

Exhibit No.	Exhibit
10(nn)* **	2016 Form of EBITDAX Performance Award-Cash under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.
10(oo)**	2016 Form of Oil Price Change vs. TSR Performance Award, under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(e) of Form 10-Q filed by the Company on May 6, 2016, File No. 001-12935).
10(pp)* **	2016 Form of Restricted Share Award to officers pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.
10(qq)* **	2016 Form of Restricted Stock Award to non-employee directors pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.
10(rr)* **	2016 Form of Deferred Stock Unit Award pursuant to the Director Deferred Compensation Plan (with respect to deferred long-term incentive awards).
10(ss)**	Standalone Restricted Share New Hire Inducement Award Agreement between Denbury Resources Inc. and Christian S. Kendall, dated September 8, 2015 (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on September 8, 2015, File No. 001-12935).
10(tt)* **	Restricted Stock Officer Promotion Award pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.
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, 2016, on oil and gas reserves (SEC Case) dated February 9, 2017.

* Included herewith.
** Compensation arrangements.

Item 16. Form 10-K Summary

None.

Denbury Resources Inc.

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.
March 1, 2017	/s/ Mark C. Allen
	Mark C. Allen Sr. Vice President and Chief Financial Officer
March 1, 2017	/s/ Alan Rhoades
	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.

March 1, 2017	/s/ Phil Rykhoek
	Phil Rykhoek Director and Chief Executive Officer (Principal Executive Officer)
March 1, 2017	/s/ Mark C. Allen
	Mark C. Allen Sr. Vice President and Chief Financial Officer (Principal Financial Officer)
March 1, 2017	/s/ Alan Rhoades
	Alan Rhoades Vice President and Chief Accounting Officer (Principal Accounting Officer)
March 1, 2017	/s/ John P. Dielwart
	John P. Dielwart Director
March 1, 2017	/s/ Michael B. Decker
	Michael B. Decker Director
March 1, 2017	/s/ Gregory L. McMichael
	Gregory L. McMichael Director
March 1, 2017	/s/ Kevin O. Meyers
	Kevin O. Meyers Director

Denbury Resources Inc.

March 1, 2017	/s/ Randy Stein Randy Stein Director
March 1, 2017	/s/ Laura A. Sugg Laura A. Sugg Director
March 1, 2017	/s/ Wieland F. Wettstein Wieland F. Wettstein 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, 333-189438, 333-206320, 333-206808 and 333-212402) and Form S-3 (No. 333-195305) of Denbury Resources Inc. of our report dated March 1, 2017 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
March 1, 2017

Exhibit 23(b)

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

February 27, 2017

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 February 9, 2017, regarding the proved reserves of Denbury Resources Inc., and to the inclusion of information taken from our reports entitled "Report as of December 31, 2016 on Reserves and Revenue of Certain Properties owned by Denbury Resources Inc. SEC Case," "Report as of December 31, 2015 on Reserves and Revenue of Certain Properties owned by Denbury Resources Inc. SEC Case," and "Appraisal Report as of December 31, 2014 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, 2016.

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.

March 1, 2017

/s/ Phil Rykhoek

Phil Rykhoek
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.

March 1, 2017

/s/ Mark C. Allen

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, 2016 (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.

Dated: March 1, 2017

/s/ Phil Rykhoek
Phil Rykhoek
Chief Executive Officer

Dated: March 1, 2017

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

CORPORATE INFORMATION

BOARD OF DIRECTORS

John P. Dielwart
Chairman of the Board
ARC Financial Corp.

Michael B. Decker
Partner
Wingate Partners

Gregory L. McMichael
Independent Consultant

Kevin O. Meyers
Independent Consultant

Phil Rykhoek
Chief Executive Officer
Denbury Resources Inc.

Randy Stein
Independent Consultant

Laura A. Sugg
Independent Consultant

Wieland F. Wettstein
President
Finex Financial Corporation Ltd.

CONTACTING BOARD MEMBERS

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

EXECUTIVE OFFICERS

Phil Rykhoek
Chief Executive Officer

Christian Kendall
President and Chief Operating Officer

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

Jim Matthews
Senior Vice President, General Counsel & Secretary

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.astfinancial.com

INVESTOR INQUIRIES

Mark Allen
Senior Vice President, Chief Financial Officer, Treasurer and Assistant Secretary
972. 673. 2000

John Mayer
Manager, Investor Relations
972. 673. 2383
Email: john.mayer@denbury.com

ANNUAL CERTIFICATIONS

During 2016, 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 the Stockholders will be held on Wednesday, May 24, 2017, at 8:00 A.M. CDT at Denbury's Corporate Headquarters, located at 5320 Legacy Drive, Plano, Texas 75024.

LEGAL COUNSEL

Baker & Hostetler LLP

BANKERS

J.P. Morgan (Agent)

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

PricewaterhouseCoopers LLP

RESERVE ENGINEERS

DeGolyer and MacNaughton

DNR LISTED NYSE

MIX
Paper from responsible sources
FSC® C132107
www.fsc.org

Denbury Resources Inc.

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