TRUE GRIT

CONCHO RESOURCES INC. | 2016 ANNUAL REPORT

INTRODUCTION

TRUE GRIT MEANS

STRENGTH OF CULTURE AND AN UNBRIDLED COMMITMENT TO A CLEAR STRATEGY. DETERMINATION IS RESILIENCE IN THE FACE OF ANY OBSTACLE. AT CONCHO, WE HAVE DELIVERED **GROWTH, VALUE AND RETURNS** YEAR AFTER YEAR BY CONSISTENTLY EXECUTING OUR **WELL-HONED STRATEGY.** WE INVEST IN HIGH-QUALITY ASSETS IN THE PERMIAN BASIN. THEN WE IMPROVE THESE ASSETS BY GROWING PRODUCTION, **CAPTURING UPSIDE POTENTIAL** AND GENERATING MORE DRILLING OPPORTUNITIES. OUR GRIT PROVIDES OUR SHAREHOLDERS WITH A SOLID INVESTMENT FOR **LONG-TERM VALUE CREATION.** AND OUR SIGHTS REMAIN ON THE TRAIL AHEAD.

DEAR SHAREHOLDERS

LETTER · TO · SHAREHOLDERS ·

In 2016, America's energy revolution proved resilient. Crude oil prices were volatile, dipping to a twelve-year low at the start of the year. Oil prices ultimately found support around $50 per barrel following an agreement to curb output by OPEC and other major producers. At these levels, oil prices are still roughly half of what they were during the five-year bull-run from 2009 to late 2014. Forced to remain competitive, the U.S. energy industry has quickly adapted to the market reality of lower oil prices. Efficiency gains have pushed U.S. shale further down the oil-supply cost curve, proving that our industry is a formidable force in the global oil market.

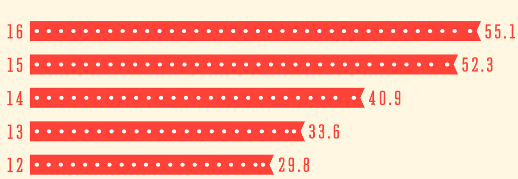
Against this backdrop, Concho continues to excel by focusing on our operations in the prolific Permian Basin and consolidating acreage in our core areas. Our proven strategy is cycle-tested and extends our lead in the Permian Basin.

In 2016, daily production averaged 151 MBoepd, up 5% from the prior year, while the total exploration and development capital expenditures totaled $1.1 billion, down 37% from 2015. Our commitment to capital discipline, cost control and a strong balance sheet was evident. Operating cash flows exceeded capital spending by $234 million. Relative to our initial outlook at the beginning of the year, we eliminated more than $120 million from our cash cost structure, which improves our cash margin and increases the speed at which we can redeploy capital into the drilling program. We also improved our balance sheet by retiring $600 million of bonds, increasing our flexibility and better positioning us to continue creating value.

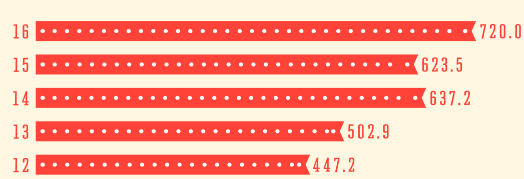
Our assets in the Permian Basin are resource rich. The oil shale revolution is underpinned by constant efficiency gains. Each year innovation enables greater resource extraction with lower capital intensity. During 2016, our proved reserve base grew 15%, and we replaced 344% of 2016 production at a record low drill-bit finding and development cost of $9.21 per Boe.

Further, the shift to long lateral and multi-well pad development – along with refining our drilling and completion designs and delineating new zones – led to significant resource expansion. Our net resource potential increased 60% year-over-year to 8 billion barrels and reflects over 19,000 gross horizontal locations across our four core areas.

ANNUAL PRODUCTION (MMBOE)



PROVED RESERVES (MMBOE)



OUR STRATEGY

Our proven strategy is built on four key principles aimed at driving profitable, consistent growth. We start by hiring the best people. Then we invest in high-quality assets in the Permian Basin, demand strong returns on our capital and maintain a strong balance sheet.

EVEN ON
ROUGH TERRAIN,
CONCHO RIDES
STRONG.

> Don't go where the path may lead, go instead
> where there is no path and leave a trail.
> – Ralph Waldo Emerson

More than a decade ago, we set out to build a Permian-focused energy company by strategically acquiring high-quality assets and profitably growing production and reserves. We have an exceptional track record of success driven by our focus on the Permian.

Today, we are the largest pure-play Permian operator, with scale and diversity as our greatest competitive advantage. Our assets are in all of the right places: the New Mexico Shelf, the Delaware Basin and the Midland Basin. We leverage our technical expertise and the latest horizontal drilling and completion techniques to convert upside potential into a growth platform for years to come.

U.S. shale is aggressively asserting itself in the global oil market. Here at home, producers – from the majors to private-equity startups – are competing head-on for Permian market share.

More than $25 billion in acquisitions transacted in the Permian during 2016. Amid the flurry, Concho's acquisition efforts were disciplined and targeted. We announced a total of $2.4 billion in property acquisitions, consolidating approximately 70,000 net acres in our core areas. Importantly, these assets illustrate the high bar we have set for acquisitions – they are value accretive and enhance our drilling inventory. We believe our drilling machine can make them even better. There is tremendous value in owning large, concentrated positions, which allows us to capture the growth and economic advantages of scale.

Our largest acquisition of the year was the purchase of the private, Midland-based operator Reliance Energy. This prominent position expanded our footprint by 35% to approximately 150,000 net acres in the core of the Midland Basin. These assets reaffirm our long-term commitment to develop the immense multi-zone potential located in our back yard.

While we continue to see a great deal of consolidation opportunities in the Permian, we remain committed to actively managing our portfolio. In addition to a disciplined strategy of pursuing the right acquisitions, we look to sell projects that have a hard time competing for capital within our portfolio. During the year, we monetized non-core assets to help fund acquisitions.

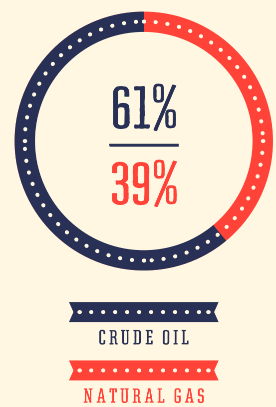
Concho had an exceptional year in 2016. Against a volatile backdrop, we achieved sustainable gains in productivity, executed attractive acquisitions and enhanced our financial strength. While we still see more volatility, not less, the outlook for Concho is solid. We will continue to prove that the consistent execution of our strategy wins. Our quality assets generate healthy margins, which support our outlook for robust growth over the next several years within cash flow.

August 2017 will mark our ten-year anniversary as a publicly traded company. I am incredibly proud of our organization and the position we have established in the Permian Basin. I want to thank our employees for their hard work and dedication, and our shareholders for their continued support.

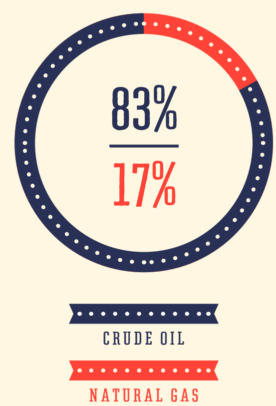
Sincerely,

Tim Leach
Chairman of the Board,
Chief Executive Officer
and President

2016 PRODUCTION MIX



2016 REVENUE MIX

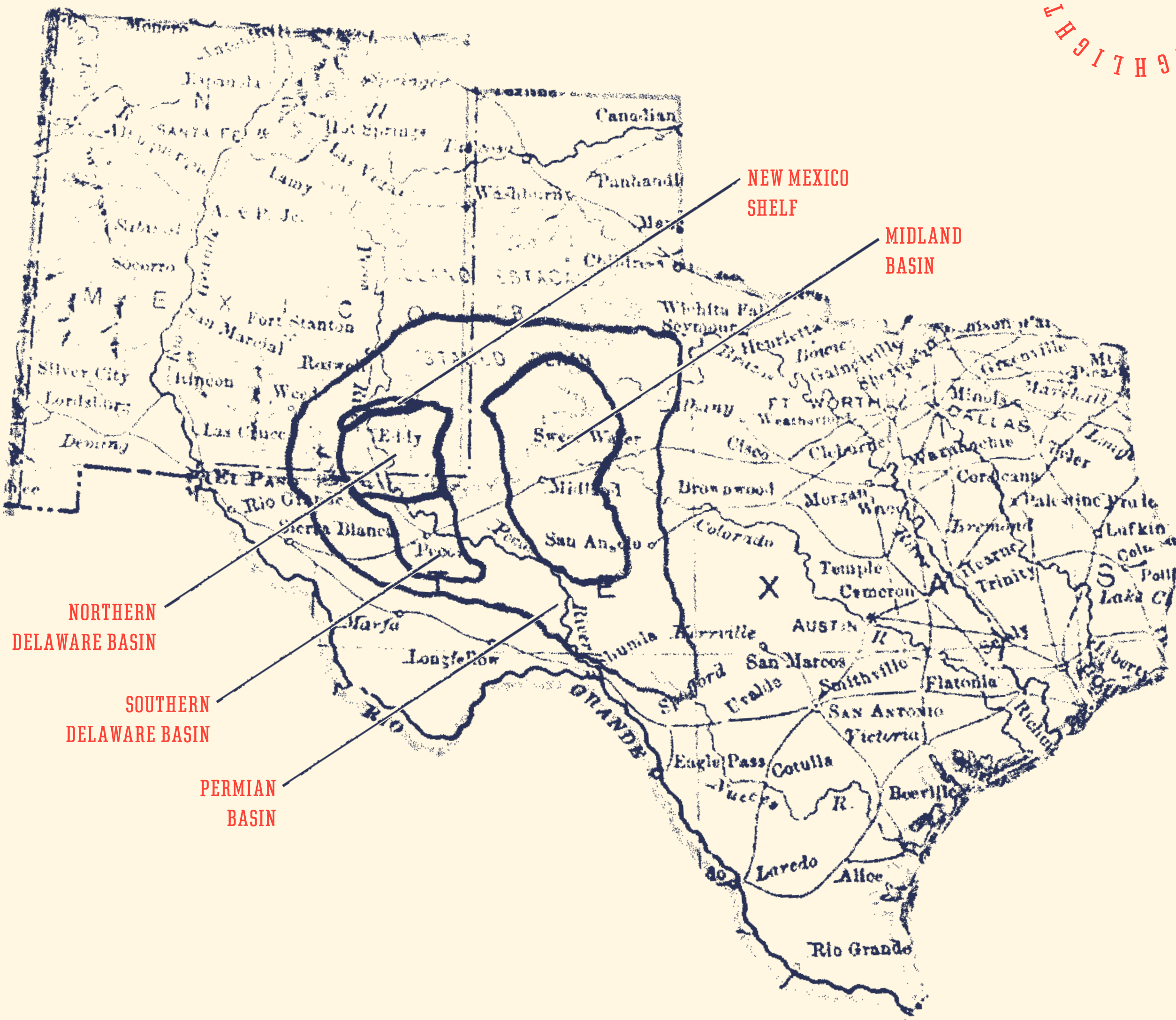


QUALITY ASSETS

Our legacy in the Permian Basin provides us with technical, operational and economic advantages that we use to aggregate the best properties in the Permian. Applying the expertise of our team and a focus on maximizing efficiencies, we can confidently project years of drilling inventory. These drilling opportunities provide a powerful engine for multi-year growth while enabling us to stay financially disciplined.

MOMENTUM

Throughout the year, we have accelerated value for shareholders by expanding profitability and improving capital productivity, enhancing the impact of each dollar we redeploy into our drilling program. This represents significant momentum that not only sets us apart, but will also help us continue to deliver long-term differentiated growth.



Headquartered in Midland, Texas, Concho is located in the heart of the Permian Basin. Within the Permian, Concho operates in the Northern Delaware Basin, the Southern Delaware Basin, the Midland Basin and the New Mexico Shelf. Across these four core areas we have identified over 19,000 gross horizontal locations.

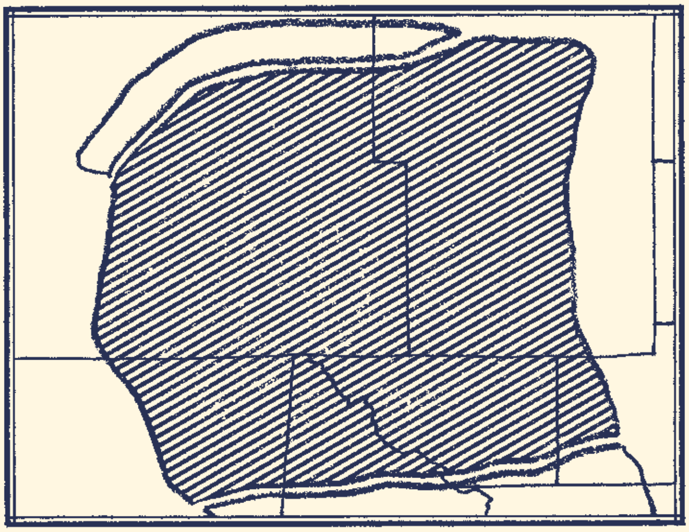
350K
GROSS ACRES IN THE NORTHERN DELAWARE BASIN

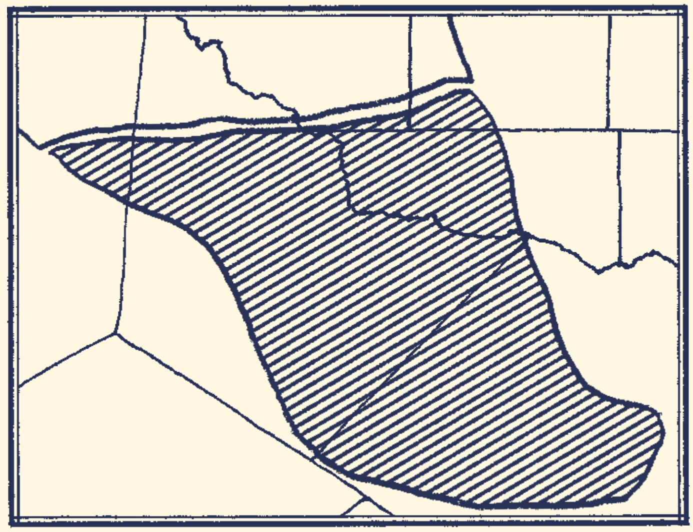
160K
GROSS ACRES IN THE SOUTHERN DELAWARE BASIN

260K
GROSS ACRES IN THE MIDLAND BASIN

130K
GROSS ACRES IN THE NEW MEXICO SHELF

AREAS · OF · OPERATION ·





NORTHERN DELAWARE BASIN

The largest of our core areas, the Northern Delaware Basin, has rapidly advanced from an exploration play to large-scale development. Over the past three years, most of our company-wide activity has focused on the Northern Delaware Basin, and some of our best projects are here.

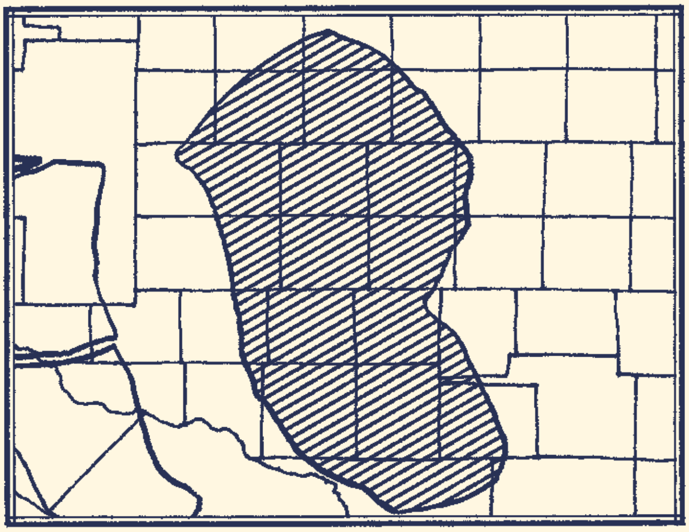
In 2016, results from our drilling program, completion optimization efforts, and down-spacing increased our inventory in the Northern Delaware Basin. Based on our well results, we have identified approximately 12,000 horizontal drilling locations in the Northern Delaware Basin targeting nine pay zones. During the year, we also achieved record lateral length and well productivity.

In the fourth quarter, we announced an opportunistic bolt-on transaction that increased our footprint in southern Lea County by more than 25%. This area is highly prospective for multi-zone development and more than doubles our long lateral drilling inventory here. We continue to capture, define and de-risk our resource, and believe there is upside potential from reducing the spacing between wells and optimizing our completion design in the Northern Delaware Basin and across all of our assets.

SOUTHERN DELAWARE BASIN

Located in Reeves, Ward and Pecos counties in Texas, our Southern Delaware Basin assets are in a target-rich setting with considerable oil in place. This area allows us to leverage our success from the Northern Delaware Basin to improve well performance and lower well costs. During 2016, we drilled some of the most prolific wells in our portfolio in this region and achieved record lateral length. We are excited about the potential this area holds.

As part of ongoing portfolio high-grading, we acquired, traded and divested acreage. In the first quarter of 2016, we acquired acreage that complements our core North Harpoon prospect and the inventory moved to the front of the line. We successfully swapped acreage in Reeves County to further consolidate our position while providing the ability to drill longer laterals. The acreage sale helped fund the acquisition in the core North Harpoon prospect. The acquisition, acreage swap and divestiture highlight our focus on actively managing and improving our portfolio of high-quality assets in the Permian Basin.

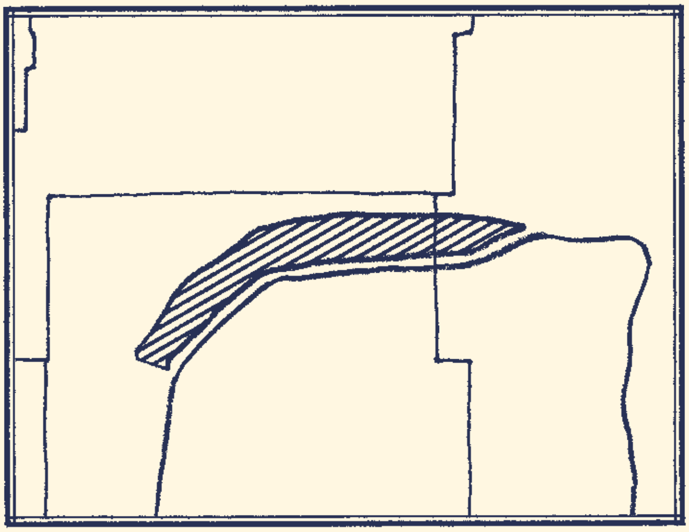


MIDLAND BASIN

The Midland Basin is a legacy area for Concho that was primarily developed through vertical wells. The transition to horizontal well development started four years ago and to date, Concho has drilled over 150 horizontal wells targeting four distinct zones.

During 2016, we made substantial progress in our horizontal program in the Midland Basin by optimizing drilling and completion methods, including increasing lateral length and shifting to pad development. These changes allow us to maximize well recoveries, gain further efficiencies and increase our resource potential.

In addition, our large, concentrated position supported the acquisition of 40,000 net acres in the core of the Midland Basin. This acquisition demonstrates our commitment to the Midland Basin and highlights our continued efforts to consolidate complementary leasehold. In line with the objectives of our Southern and Northern Delaware Basin acquisitions, the assets we acquired helped high-grade our inventory with additional long lateral locations that compete with the best projects in the Permian Basin.



NEW MEXICO SHELF

Historically a major contributor to our overall production growth for Concho, the New Mexico Shelf is a world-class asset with high rate of return drilling opportunities.

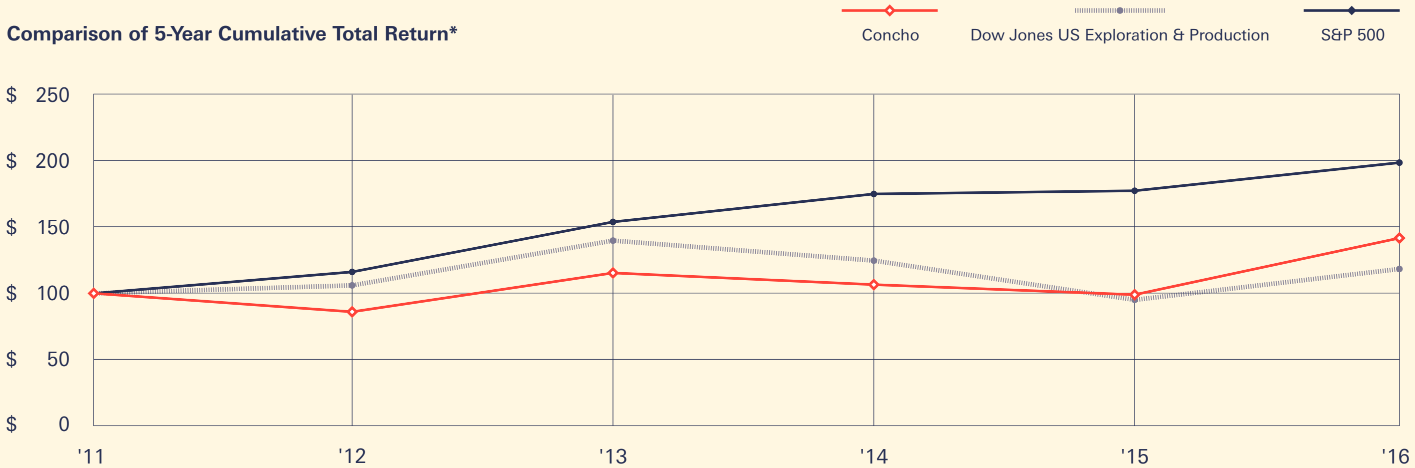
Since 2006, we have drilled more than 1,300 vertical wells in the New Mexico Shelf targeting the Yeso formation. In 2016 we drilled approximately 40 horizontal wells. By applying horizontal drilling and advanced completion techniques, we are expanding the boundaries of this legacy asset and increasing our resource potential. These low-cost, shallow opportunities have some of the best economics in our portfolio and generate significant cash flow to redeploy in our other core areas.

FINANCIAL · HIGHLIGHTS ·

($ In Thousands)	2016	2015	2014	2013	2012
Oil Sales	$ 1,350,367	$ 1,539,917	$ 2,189,072	$ 1,938,433	$ 1,482,998
Natural Gas Sales	284,621	263,656	471,075	381,486	336,816
Total Operating Revenues	1,634,988	1,803,573	2,660,147	2,319,919	1,819,814
Operating Costs and Expenses	(3,704,432)	(1,476,359)	(1,579,710)	(1,703,750)	(969,623)
Other Expenses	(269,092)	(229,943)	(224,477)	(259,010)	(190,920)
Income (Loss) from Continuing Operations Before Income Taxes	(2,338,536)	97,271	855,960	357,159	659,271
Income Tax Expense (Benefit)	876,090	(31,371)	(317,785)	(118,237)	(251,041)
Income from Discontinued Operations, Net of Tax	—	—	—	12,081	23,459
Net Income (Loss)	$ (1,462,446)	$ 65,900	$ 538,175	$ 251,003	$ 431,689
EBITDAX[A]	$ 1,633,158	$ 1,712,910	$ 2,033,225	$ 1,685,592	$ 1,475,628
Production (MMBoe)	55.1	52.3	40.9	33.6	29.8
Proved Reserves	720.0	623.5	637.2	502.9	447.2

(A) The Company defines EBITDAX as net income (loss), plus (1) exploration and abandonments expense, (2) depreciation, depletion and amortization expense, (3) accretion expense, (4) impairments of long-lived assets, (5) non-cash stock-based compensation expense, (6) (gain) loss on derivatives, (7) net cash receipts from derivatives, (8) (gain) loss on disposition of assets, net, (9) interest expense, (10) loss on extinguishment of debt and (11) federal and state income tax expense (benefit). EBITDAX is not a measure of net income (loss) or cash flows as determined by GAAP. See "Item 1. Business–Non-GAAP Financial Measures and Reconciliations" in our 2016 Annual Report on Form 10-K included herein.

Comparison of 5-Year Cumulative Total Return*



*$100 invested on 12/31/11 in stock or index, including reinvestment of dividends. Fiscal year ending December 31.

FORM 10-K

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

☑ **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: 1-33615

Concho Resources Inc.

(Exact name of registrant as specified in its charter)

Delaware	**76-0818600**
State or other jurisdiction of incorporation or organization	(I.R.S. Employer Identification No.)
One Concho Center 600 West Illinois Avenue Midland, Texas	**79701**
(Address of principal executive offices)	(Zip code)

(432) 683-7443

Registrant's telephone number, including area code

Securities Registered Pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, $0.001 par value	**New York Stock Exchange**

Securities Registered Pursuant to Section 12(g) of the Act: **None**

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) 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 (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

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

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

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter:	$ 15,544,307,866
Number of shares of the registrant's common stock outstanding as of February 17, 2017:	148,162,936

Documents Incorporated by Reference:

Portions of the registrant's definitive proxy statement for its 2017 Annual Meeting of Stockholders, which will be filed with the United States Securities and Exchange Commission within 120 days of December 31, 2016, are incorporated by reference into Part III of this Form 10-K for the year ended December 31, 2016.

TABLE OF CONTENTS

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements and information contained in or incorporated by reference into this report that express a belief, expectation, or intention, or that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 (the "Exchange Act"). These forward-looking statements include statements, projections and estimates concerning our future financial position, operations, performance, business strategy, oil and natural gas reserves, drilling program, capital expenditures, liquidity and capital resources, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, derivative activities and potential financing. Forward-looking statements are generally accompanied by words such as "estimate," "project," "predict," "believe," "expect," "anticipate," "potential," "could," "may," "foresee," "plan," "goal" or other words that convey the uncertainty of future events or outcomes. Forward-looking statements are not guarantees of performance. We have based these forward-looking statements on our current expectations and assumptions about future events and their potential effect on us. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. Actual results may differ materially from those implied or expressed by any forward-looking statements. These forward-looking statements speak only as of the date of this report, or if earlier, as of the date they were made. We disclaim any obligation to update or revise these statements unless required by law, and we caution you not to rely on them unduly. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties relating to, among other matters, the risks discussed in "Item 1A. Risk Factors" in this report, as well as those factors summarized below:

- declines in, or the sustained depression of, the prices we receive for our oil and natural gas;
- uncertainties about the estimated quantities of oil and natural gas reserves;
- drilling, completion and operating risks;
- the adequacy of our capital resources and liquidity including, but not limited to, access to additional borrowing capacity under our credit facility;
- the effects of government regulation, permitting and other legal requirements, including new legislation or regulation of hydraulic fracturing and the export of oil and natural gas;
- the impact of potential changes in our credit ratings;
- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater contamination;
- difficult and adverse conditions in the domestic and global capital and credit markets;
- risks related to the concentration of our operations in the Permian Basin of Southeast New Mexico and West Texas;
- disruptions to, capacity constraints in or other limitations on the pipeline systems that deliver our oil, natural gas liquids and natural gas and other processing and transportation considerations;
- the costs and availability of equipment, resources, services and qualified personnel required to perform our drilling and operating activities;
- potential financial losses or earnings reductions from our commodity price risk-management program;
- risks and liabilities associated with acquired properties or businesses;
- uncertainties about our ability to successfully execute our business and financial plans and strategies;
- uncertainties about our ability to replace reserves and economically develop our current reserves;
- general economic and business conditions, either internationally or domestically;
- competition in the oil and natural gas industry; and
- uncertainty concerning our assumed or possible future results of operations.

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and the price and cost assumptions made by our reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ from the quantities of oil and natural gas that are ultimately recovered.

PART I

Item 1. Business

General

Concho Resources Inc., a Delaware corporation ("Concho," the "Company," "we," "us" and "our") formed in February 2006, is an independent oil and natural gas company engaged in the acquisition, development, exploration and production of oil and natural gas properties. Our core operations are focused in the Permian Basin of southeast New Mexico and west Texas. The Permian Basin is one of the most prolific oil and natural gas producing regions in the United States and is characterized by an extensive production history, long reserve life, multiple producing horizons and enhanced recovery potential. Currently, the majority of the rigs running in the Permian Basin are drilling horizontal wells. Concho's legacy in the Permian Basin provides us a deep understanding of operating and geological trends. We are actively applying new technologies, such as extended length lateral drilling and enhanced completion techniques, throughout our four core operating areas: the Northern Delaware Basin, the Southern Delaware Basin, the Midland Basin and the New Mexico Shelf. Our strategy remains focused on development and exploration activities on our multi-year project inventory and pursuing acquisitions that meet our strategic and financial objectives.

Acquisitions

Reliance Acquisition

In October 2016, we completed an acquisition of approximately 40,000 net acres in the Northern Midland Basin and other assets from Reliance Energy, Inc. (collectively, the "Reliance Acquisition") for approximately \$1.7 billion. As consideration for the acquisition, we paid approximately \$1.2 billion in cash and issued to the seller approximately 3.9 million shares of common stock with an approximate value of \$0.5 billion.

Business and Properties

Our core operations are focused in the Permian Basin, which underlies an area of Southeast New Mexico and West Texas approximately 250 miles wide and 300 miles long. Commercial accumulations of hydrocarbons occur in multiple stratigraphic horizons, at depths ranging from less than 1,000 feet to over 25,000 feet. At December 31, 2016, substantially all of our 720.0 MMBoe total estimated proved reserves were located in our core operating areas and consisted of approximately 59.5 percent oil and 40.5 percent natural gas. We have assembled a multi-year inventory of horizontal development and exploration projects, including projects to further evaluate the regional extent and multi-pay potential of our Northern Delaware Basin, Southern Delaware Basin, Midland Basin and New Mexico Shelf assets.

The following table sets forth information with respect to drilling of wells commenced during the periods indicated:

	Years Ended December 31,		
	2016	2015	2014
Gross wells	249	361	595
Net wells	170	228	370
Percent of gross wells drilled horizontally	99.6%	85.9%	69.1%
Percent of gross wells:			
Producers	56.2%	73.7%	69.9%
Unsuccessful	-	0.8%	0.2%
Awaiting completion at year-end	43.8%	25.5%	29.9%
	100.0%	100.0%	100.0%

In 2016, we drilled 99.6 percent of our wells horizontally. In 2017, we intend to spend substantially all of our capital plan for drilling and completion activities on horizontal opportunities.

We produced approximately 55.1 MMBoe, 52.3 MMBoe and 40.9 MMBoe of oil and natural gas during 2016, 2015 and 2014, respectively. During 2016, approximately 76 percent of our total production was attributable to horizontal wells. During 2016, our total estimated proved reserves increased by approximately 96.5 MMBoe, primarily due to (i) 124.8 MMBoe of extensions and discoveries, (ii) 59.1 MMBoe of acquisitions and (iii) 63.3 MMBoe of positive technical and performance revisions primarily related to decreased lease operating expenses, which were partially offset by (i) 57.4 MMBoe of negative revisions due to proved undeveloped reserves reclassified to unproved reserves because they are no longer expected to be developed within five years of their initial recording, (ii) negative price revisions of 29.9 MMBoe, (iii) current year production of 55.1 MMBoe and (iv) 8.3 MMBoe from various divestitures completed throughout the year.

Summary of Core Operating Areas and Other Plays

The following is a summary of information regarding our core operating areas and other plays:

	December 31, 2016					
Areas	Estimated Proved Reserves (MBoe)	% Oil	% Proved Developed	Total Gross Acreage	Total Net Acreage	2016 Average Daily Production (Boe per Day)
Core Operating Areas:						
Northern Delaware Basin	234,342	51.2%	62.0%	353,384	246,821	73,369
Southern Delaware Basin	107,977	73.7%	50.3%	157,248	99,650	19,883
Midland Basin	191,388	63.4%	67.8%	256,462	157,699	25,476
New Mexico Shelf	186,142	57.6%	73.2%	126,395	82,048	31,740
Other	118	7.1%	100.0%	1,338	789	43
Total	719,967	59.5%	64.7%	894,827	587,007	150,511

Core operating areas

Northern Delaware Basin. At December 31, 2016, we had estimated proved reserves in this area of 234.3 MMBoe, representing 32.5 percent of our total proved reserves.

The Northern Delaware Basin is characterized by a thick, resource-rich hydrocarbon column that lends itself to multi-zone development. We leverage leading-edge horizontal drilling and completion technologies to target multiple producing formations that comprise the Avalon Shale, Bone Spring and Wolfcamp. These formations produce from 6,500 feet to 13,500 feet for our currently targeted activity.

During the year ended December 31, 2016, we commenced drilling or participated in the drilling of 80 (55 net) wells in this area. Throughout 2016, we completed 95 (72 net) wells that are producing. Additionally in 2016, we abandoned 1 (1 net) well that was deemed unsuccessful. During 2016, we continued (i) development and step-out activity targeting the Avalon shale, Bone Spring sands and Wolfcamp shale and (ii) evaluation of our enhanced stimulation procedures of certain horizontal wells. During 2016, all of the wells we commenced, or participated in, drilling were drilled horizontally.

In 2017, we intend to spend approximately 38 percent of our 2017 drilling and completions capital plan on our Northern Delaware Basin assets.

Southern Delaware Basin. At December 31, 2016, we had estimated proved reserves in this area of 108.0 MMBoe, representing 15.0 percent of our total proved reserves.

Across our Southern Delaware Basin acreage position we primarily target the Bone Spring and Wolfcamp formations, which generally range from 4,700 feet to 13,500 feet in depth.

During the year ended December 31, 2016, we commenced drilling or participated in the drilling of 41 (30 net) wells in this area. Throughout 2016, we completed 30 (21 net) wells that are producing. During 2016, we continued (i) development and step-out activity targeting the Bone Spring sands and Wolfcamp shale and (ii) evaluation of our enhanced stimulation procedures of certain horizontal wells. During 2016, all of the wells we commenced or participated in drilling were drilled horizontally.

In 2017, we intend to spend approximately 24 percent of our 2017 drilling and completions capital plan on our Southern Delaware Basin assets.

Midland Basin. At December 31, 2016, we had estimated proved reserves in this area of 191.4 MMBoe, representing 26.6 percent of our total proved reserves.

Our primary objectives in the Midland Basin area are the Spraberry and Wolfcamp formations, which are typically encountered at depths of 7,500 feet to 11,500 feet. On our Midland Basin assets we are continuing to develop the Wolfcamp and Spraberry formations with horizontal drilling, utilizing multi-well pad sites and extended lateral development. We are also continuing to optimize completion techniques and well spacing.

During the year ended December 31, 2016, we commenced drilling or participated in the drilling of 86 (47 net) wells in this area. Throughout 2016, we completed 42 (22 net) wells that are producing. During 2016, substantially all of the wells we commenced or participated in drilling were drilled horizontally.

In 2017, we intend to spend approximately 29 percent of our 2017 drilling and completions capital plan on our Midland Basin assets.

New Mexico Shelf. At December 31, 2016, we had estimated proved reserves in this area of 186.1 MMBoe, representing 25.9 percent of our total proved reserves.

Within this area our primary objectives are the Yeso, San Andres and Grayburg formations, with producing depths ranging from approximately 900 feet to 7,500 feet. During 2016, we continued our horizontal drilling of the Yeso formation.

During the year ended December 31, 2016, we commenced drilling or participated in the drilling of 42 (38 net) wells in this area. Throughout 2015, we completed 59 (45 net) wells that are producing. During 2016, substantially all of the wells we commenced or participated in drilling were drilled horizontally.

In 2017, we intend to spend approximately 9 percent of our 2017 drilling and completions capital plan on our New Mexico Shelf assets.

Drilling Activities

The following table sets forth information with respect to (i) wells drilled and completed during the periods indicated and (ii) wells drilled in a prior period but completed in the periods indicated. The information should not be considered indicative of future performance, nor should a correlation be assumed between the number of productive wells drilled, quantities of reserves found or economic value.

	Years Ended December 31,					
	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	95	76	180	116	201	128
Dry	-	-	1	1	1	1
Exploratory wells:						
Productive	131	83	260	154	312	190
Dry	1	1	3	2	11	10
Total wells:						
Productive	226	159	440	270	513	318
Dry	1	1	4	3	12	11
Total	227	160	444	273	525	329

The following table sets forth information about wells for which drilling was in-progress or are pending completion at December 31, 2016, which are not included in the above table:

	Drilling In-Progress		Pending Completion	
	Gross	Net	Gross	Net
Development wells	17	12	14	8
Exploratory wells	19	13	66	30
Total	36	25	80	38

Our Production, Prices and Expenses

The following table sets forth summary information concerning our production and operating data for the years ended December 31, 2016, 2015 and 2014. The actual historical data in this table excludes results from the Reliance Acquisition for periods prior to October 2016. Because of normal production declines, increased or decreased drilling activities, fluctuations in commodity prices and the effects of acquisitions or divestitures, the historical information presented below should not be interpreted as being indicative of future results.

	Years Ended December 31,		
	2016	2015	2014
Production and operating data:			
Net production volumes:			
Oil (MBbl)	33,840	34,457	26,319
Natural gas (MMcf)	127,481	106,987	87,336
Total (MBoe)	55,087	52,288	40,875
Average daily production volumes:			
Oil (Bbl)	92,459	94,403	72,107
Natural gas (Mcf)	348,309	293,115	239,277
Total (Boe)	150,511	143,256	111,987
Average prices per unit:			
Oil, without derivatives (Bbl)	$ 39.90	$ 44.69	$ 83.17
Oil, with derivatives (Bbl) (a)	$ 57.90	$ 62.03	$ 86.07
Natural gas, without derivatives (Mcf)	$ 2.23	$ 2.46	$ 5.39
Natural gas, with derivatives (Mcf) (a)	$ 2.36	$ 2.80	$ 5.34
Total, without derivatives (Boe)	$ 29.68	$ 34.49	$ 65.08
Total, with derivatives (Boe) (a)	$ 41.03	$ 46.60	$ 66.84
Operating costs and expenses per Boe:			
Lease operating expenses and workover costs	$ 5.81	$ 7.46	$ 8.05
Oil and natural gas taxes	$ 2.38	$ 2.90	$ 5.12
Depreciation, depletion and amortization	$ 21.19	$ 23.40	$ 23.97
General and administrative	$ 4.09	$ 4.42	$ 4.99

(a) Includes the effect of net cash receipts from (payments on) derivatives:

	Years Ended December 31,		
(in thousands)	2016	2015	2014
Net cash receipts from (payments on) derivatives:			
Oil derivatives	$ 608,847	$ 597,297	$ 76,335
Natural gas derivatives	16,403	35,619	(4,352)
Total	$ 625,250	$ 632,916	$ 71,983

The presentation of average prices with derivatives is a result of including the net cash receipts from (payments on) commodity derivatives that are presented in our statements of cash flows. This presentation of average prices with derivatives is a means by which to reflect the actual cash performance of our commodity derivatives for the respective periods and presents oil and natural gas prices with derivatives in a manner consistent with the presentation generally used by the investment community.

Productive Wells

The following table sets forth the number of productive oil and natural gas wells on our properties at December 31, 2016, 2015 and 2014. This table does not include wells in which we own a royalty interest only.

	Gross Productive Wells			Net Productive Wells		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
December 31, 2016						
Core Operating Areas:						
Northern Delaware Basin	1,164	454	1,618	662	212	874
Southern Delaware Basin	270	27	297	163	17	180
Midland Basin	2,577	15	2,592	1,298	5	1,303
New Mexico Shelf	3,222	126	3,348	2,560	33	2,593
Other	-	3	3	-	-	-
Total	7,233	625	7,858	4,683	267	4,950
December 31, 2015						
Core Operating Areas:						
Northern Delaware Basin	1,141	460	1,601	651	217	868
Southern Delaware Basin	222	53	275	138	29	167
Midland Basin	2,476	24	2,500	1,173	8	1,181
New Mexico Shelf	3,143	114	3,257	2,531	42	2,573
Other	-	3	3	-	0	0
Total	6,982	654	7,636	4,493	296	4,789
December 31, 2014						
Core Operating Areas:						
Northern Delaware Basin	957	429	1,386	527	191	718
Southern Delaware Basin	185	47	232	94	24	118
Midland Basin	2,436	44	2,480	1,147	19	1,166
New Mexico Shelf	2,994	113	3,107	2,427	46	2,473
Other	-	3	3	-	0	0
Total	6,572	636	7,208	4,195	280	4,475

Marketing Arrangements

General. We market our oil and natural gas in accordance with standard energy industry practices. The marketing effort is coordinated with our operations group as it relates to the planning and preparation of future drilling programs so that available markets can be assessed and secured. This planning also involves the coordination of access to the physical facilities necessary to connect new producing wells as efficiently as possible upon their completion.

Oil. We generally do not transport our oil, and we do not refine or process the oil we produce. A portion of our oil in Southeast New Mexico is connected directly to oil gathering pipelines. Most of our gathered oil from the New Mexico Shelf is utilized in a two-refinery complex in Southeast New Mexico. Most of the oil production from the New Mexico portion of our Northern Delaware Basin core area is now connected to the Alpha Crude Connector, LLC ("ACC") pipeline system. Most of the oil production connected to the ACC pipeline system is purchased by three different purchasers and moved on several different pipeline outlets off ACC. We have assigned our shipping rights on ACC to these purchasers and they purchase our production at the receipt points into ACC. The remaining oil in our Northern Delaware Basin core area that is not on ACC is purchased by approximately ten different oil purchasers and trucked to pipeline stations in the area.

Most of our oil in the Southern Delaware Basin is on one of three different oil gathering systems in the area. We have a partial ownership in one of those gathering systems. The oil is then transported to the Crane/Midland/Colorado City pipeline corridor and then onto Cushing or Gulf Coast markets. A significant portion of our Midland Basin production is on one of five different gathering systems. Most of this production is sweet crude and is transported by third parties to the Cushing or the Gulf Coast market. The balance of our oil in these areas that is not directly connected to pipeline is trucked to unloading stations on those same pipelines. We sell the majority of the oil we produce under contracts using market-based pricing. This price is then adjusted for differentials based upon delivery location and oil quality.

Natural Gas. We consider all natural gas gathering and delivery infrastructure in the areas of our production and evaluate market options to obtain the best price reasonably available under the circumstances. We sell the majority of our natural gas under individually negotiated natural gas purchase contracts using market-based pricing. The majority of our natural gas is subject to long-term agreements that generally extend five to ten years from the effective date of the subject contract.

The majority of the natural gas we sell is casinghead gas sold at the lease location under percentage of proceeds processing contracts; however, we are currently transitioning to a mixture of percentage of proceeds and fee based contracts. The purchaser gathers our casinghead natural gas in the field where it is produced and transports it via pipeline to a natural gas processing plant where natural gas liquid products are extracted and sold by the processor. The remaining natural gas product is residue gas, or dry gas, which is placed on residue pipeline systems available in the area. Under our percentage of proceeds contracts, we receive a percentage of the value for the extracted liquids and the residue gas.

Our Principal Customers

We sell our oil and natural gas production principally to marketers and other purchasers that have access to pipeline facilities. In areas where there is no practical access to pipelines, oil is transported to storage facilities by trucks and rail owned or otherwise arranged by the marketers or purchasers. Our marketing of oil and natural gas can be affected by factors beyond our control, the effects of which cannot be accurately predicted.

For 2016, revenues from oil and natural gas sales to Plains Marketing and Transportation, Inc. and Holly Frontier Refining and Marketing, LLC accounted for approximately 29 percent and 16 percent, respectively, of our total operating revenues. While the loss of either of these purchasers may result in a temporary interruption in sales of, or a lower price for, our production, we believe that the loss of either of these purchasers would not have a material adverse effect on our operations, as there are alternative purchasers in our producing regions.

Competition

The oil and natural gas industry in the areas in which we operate is highly competitive. We encounter strong competition from numerous parties, ranging generally from small independent producers to major integrated companies. We primarily encounter significant competition in acquiring properties. At higher commodity prices, we also face competition in contracting for drilling, pressure pumping and workover equipment and securing trained personnel. Many of these competitors have financial, technical and personnel resources substantially larger than ours. As a result, our competitors may be able to pay more for desirable properties, or to evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources will permit.

In addition to competition for drilling, pressure pumping and workover equipment, we are also affected by the availability of related equipment and materials. The oil and natural gas industry periodically experiences shortages of drilling and workover rigs, equipment, pipe, materials and personnel, which can delay drilling, workover and exploration activities and cause significant price increases. We are unable to predict the timing or duration of any such shortages.

Working Capital

Based on current market conditions, we have maintained a stable liquidity position. Our principal sources of liquidity are cash on hand and available borrowing capacity under our credit facility. At December 31, 2016, we had no debt outstanding under our credit facility and more than $2.6 billion of liquidity available, including $53.3 million in cash and cash equivalents and $2.5 billion of unused commitments under our credit facility. Subsequent to December 31, 2016, our cash position will be increased by our disposition of ACC for approximately $802.8 million and reduced by our Northern Delaware Basin acquisition for approximately $107.0 million, resulting in a net increase of $695.8 million. Our primary needs for cash are development, exploration and acquisition of oil and natural gas assets, payment of contractual obligations and working capital obligations. However, additional borrowings under our credit facility or the issuance of additional debt securities will require a greater portion of our cash flow from operations to be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flow to fund working capital, capital expenditures and acquisitions.

In February 2017, we announced our updated 2017 capital budget, excluding acquisitions, of approximately $1.8 billion with expected capital spending to range between $1.6 billion and $1.8 billion. Approximately 90 percent of capital will be directed to drilling and completion activity. Our 2017 capital program is expected to continue focusing on extended length lateral drilling. Our 2017 capital budget, based on our current expectations of commodity prices and costs, is expected to be within our cash flows. Our budget could change depending on numerous factors, including commodity prices, leverage metrics and industry conditions. However, if we were to outspend our cash flows, we could use our cash on hand, credit facility and other financing sources. We believe that we have adequate availability under our credit facility to fund any cash flow deficits. Our liquidity position, along with internally generated cash flows from operations, is expected to provide continued financial flexibility as we actively manage the pace of exploration and development activities and acquisitions of leasehold acreage. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Commitments, Capital Resources and Liquidity" for additional information regarding our liquidity and ability to fund working capital.

Applicable Laws and Regulations

Regulation of the Oil and Natural Gas Industry

***Regulation of transportation and sale of oil**.* Prices at which sales of oil, condensate and natural gas liquids are made are not currently regulated, and sales of these products are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our sales of oil are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The Federal Energy Regulatory Commission (the "FERC") regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system that permits an oil pipeline, subject to limited challenges, to annually increase or decrease its transportation rates due to inflationary changes in costs using a FERC approved index, without making a cost of service filing. Every five years, the FERC reviews the appropriateness of the index in relation to industry costs. On December 17, 2015, the FERC established a new Producer Price Index for Finished Goods (the "PPI-FG") of PPI-FG plus 1.23 percent for the five-year period beginning July 1, 2016. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis at posted tariff rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Effective November 4, 2009, pursuant to the Energy Independence and Security Act of 2007, the Federal Trade Commission (the "FTC") issued a rule prohibiting market manipulation in the petroleum industry. The FTC rule prohibits any person, directly or indirectly, in connection with the purchase or sale of oil, gasoline or petroleum distillates at wholesale, from knowingly engaging in any act, practice or course of business, including the making of any untrue statement of material fact, that operates or would operate as a fraud or deceit upon any person, or intentionally failing to state a material fact that under the circumstances renders a statement made by such person misleading, provided that such omission distorts or is likely to distort market conditions for any such product. A violation of this rule may result in civil penalties of up to $1 million per day per violation, in addition to any applicable penalty under the Federal Trade Commission Act.

***Regulation of transportation and sale of natural gas**.* Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938 (the "Natural Gas Act"), the Natural Gas Policy Act of 1978 (the "Natural Gas Policy Act") and regulations issued under those acts by the FERC. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future, and market participants are prohibited from engaging in market manipulation. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all Natural Gas Act and Natural Gas Policy Act price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993.

The FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, the FERC issued Order No. 636 and a series of related orders to implement its open access policies. As a result of the Order No. 636 program, the marketing and pricing of natural gas have been significantly altered. The interstate pipelines' traditional role as wholesalers of natural gas has been eliminated and replaced by a structure under which pipelines provide transportation and storage services on an open access basis to others who buy and sell natural gas. Although these orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

In 2000, the FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting.

In August 2005, Congress enacted the Energy Policy Act of 2005 ("EPAct 2005"). Among other matters, EPAct 2005 amends the Natural Gas Act to make it unlawful for "any entity," including otherwise non-jurisdictional producers such as us, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the FERC, in contravention of rules prescribed by the FERC. The FERC's rules implementing this provision make it unlawful, in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the Natural Gas Act or Natural Gas Policy Act up to $1 million per day per violation. The new anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales, gathering or production, but does apply to activities of otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" natural gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order No. 704, as described below. EPAct 2005 therefore reflects a significant expansion of the FERC's enforcement authority. We do not anticipate we will be affected any differently than other producers of natural gas.

In December 2007, the FERC issued a rule ("Order No. 704"), as clarified in orders on rehearing, requiring that any market participant, including a producer such as us, that engages in wholesale sales or purchases of natural gas that equal or exceed 2.2 million MMBtus during a calendar year to annually report, starting May 1, 2009, such sales and purchases to the FERC. These rules are intended to increase the transparency of the wholesale natural gas markets and to assist the FERC in monitoring such markets and in detecting market manipulation. We do not anticipate that we will be affected by these rules any differently than other producers of natural gas.

We cannot accurately predict whether the FERC's actions will achieve the goal of increasing competition in markets in which our natural gas is sold. Additional proposals and proceedings that might affect the natural gas industry are pending before the FERC and the courts. The natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by the FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, the FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of getting natural gas to point of sale locations.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. During the 2007 legislative session, the Texas State Legislature passed H.B. 3273 (the "Competition Bill") and H.B. 1920 (the "LUG Bill"). The Competition Bill gives the Railroad Commission of Texas (the "RRC") the ability to use either a cost-of-service method or a market-based method for setting rates for natural gas gathering and intrastate transportation pipelines in formal rate proceedings. It also gives the RRC specific authority to enforce its statutory duty to prevent discrimination in natural gas gathering and transportation, to enforce the requirement that parties participate in an informal complaint process and to penalize purchasers, transporters, and gatherers for taking discriminatory actions against shippers and sellers. The Competition Bill also provides producers with the unilateral option to determine whether or not confidentiality provisions are included in a contract to which a producer is a party for the sale, transportation or gathering of natural gas. The LUG Bill modifies the informal complaint process at the RRC with procedures unique to lost and unaccounted for natural gas issues. It extends the types of information that can be requested, provides producers with an annual audit right, and provides the RRC with the authority to make determinations and issue orders in specific situations. Both the Competition Bill and the LUG Bill became effective on September 1, 2007, and the RRC rules implementing the RRC's authority pursuant to the bills became effective on April 28, 2008.

Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Regulation of production. The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and the plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Environmental, Health and Safety Matters

General. Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment. These laws, rules and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas drilling and production and saltwater disposal activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, environmental laws and regulations are revised frequently, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

The following is a summary of some of the existing laws, rules and regulations to which our business is subject.

Waste handling. The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Pursuant to regulatory guidance issued by the federal Environmental Protection Agency (the "EPA"), the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of oil or natural gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. For example, in December 2016, the EPA and certain environmental organizations entered into a consent decree to address EPA's alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and gas wastes from regulation as hazardous wastes under RCRA. The consent decree requires EPA to propose a rulemaking no later than March 15, 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or to sign a determination that revision of the regulations is not necessary. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position. Also, in the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes if such wastes have hazardous characteristics.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response Compensation and Liability Act ("CERCLA"), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose storage, treatment and disposal of hazardous substances, wastes or hydrocarbons were not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property, or perform remedial operations to prevent future contamination.

Water discharges. The federal Water Pollution Control Act (the "Clean Water Act") and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters, including dredge and fill activities in regulated wetlands, is prohibited, except in accordance with the terms of a permit issued by the EPA, or, in some circumstances, the U.S. Army Corps of Engineers (the "Corps"), or an analogous state agency. In September 2015, new EPA and U.S. Army Corps of Engineers rules defining the scope of the EPA's and the Corps' jurisdiction became effective. To the extent the rule expands the scope of jurisdiction of the Clean Water Act, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. The rule has been challenged in court on the grounds that it unlawfully expands the reach of Clean Water Act programs, and implementation of the rule has been stayed pending resolution of the court challenge. In addition, spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

Safe Drinking Water Act. Our oil and natural gas exploration and production operations generate produced water, drilling muds, and other waste streams, some of which may be disposed via injection in underground wells situated in non-producing subsurface formations. The drilling and operation of these injection wells are regulated by the federal Safe Drinking Water Act (the "SDWA"). The Underground Injection Well Program under the SDWA requires that we obtain permits from the EPA or delegated state agencies for our disposal wells, establishes minimum standards for injection well operations, restricts the types and quantities of fluids that may be injected and prohibits the migration of fluid containing any contaminants into underground sources of drinking water. Any leakage from the subsurface portions of the injection wells may cause degradation of freshwater, potentially resulting in cancellation of operations of a well, imposition of fines and penalties from governmental agencies, incurrence of expenditures for remediation of affected resources, and imposition of liability by landowners or other parties claiming damages for alternative water supplies, property damages, and personal injuries. Any changes in the laws or regulations or the inability to obtain permits for new injection wells in the future may affect our ability to dispose of produced waters and would ultimately increase the cost of our operations, which costs could be significant. For example, the RRC recently adopted new permit rules for injection wells to address seismic activity concerns within the state. Among other things, the rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells, and allow the RRC to modify, suspend, or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. Furthermore, in response to recent seismic events near underground injection wells used for the disposal of oil and gas-related wastewaters, federal and some state agencies have begun investigating whether such wells have caused increased seismic activity, and some states have shut down or imposed moratoria on the use of such injection wells. For example, in 2016, the Oklahoma Corporation Commission issued various orders and regulations applicable to disposal operations in specific counties in Oklahoma. These rules require that disposal well operators, among other things, conduct additional mechanical integrity testing, make sure that their wells are not injecting wastes into targeted formations, and/or reduce the volumes of wastes disposed in such wells. If new regulatory initiatives are implemented that restrict or prohibit the use of underground injection wells in areas where we rely upon the use of such wells in our operations, our costs to operate may significantly increase, and our ability to continue production may be delayed or limited, which could have a material adverse effect on our results of operations and financial position.

Air emissions. The federal Clean Air Act (the "CAA"), and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources.

For example, in October 2015, the EPA lowered the National Ambient Air Quality Standard ("NAAQS") for ozone from 75 to 70 parts per billion. State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant. In addition, in June 2016, the EPA finalized rules under the CAA regarding criteria for aggregating multiple sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities (such as tank batteries), on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements, which in turn could result in operational delays or require us to install costly pollution control equipment. In a separate rulemaking in June 2016, the EPA finalized new air emission control requirements for emissions of methane from certain equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities. The final rule package includes first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions, and also imposes leak detection and repair requirements on operators. In addition, the rule package extends existing volatile organic compound ("VOC") standards under the EPA's Subpart OOOO of the New Source Performance Standards to include previously unregulated equipment within the oil and natural gas source category. The U.S. Bureau of Land Management ("BLM") finalized similar rules in November 2016 that limit methane emissions from new and existing oil and gas operations on federal lands through limitations on the venting and flaring of gas, as well as enhanced leak detection and repair requirements. The BLM adopted final rules in January 2017; however, operators generally have one year from the January 2017 effective date of the rule to come into compliance with the rule's requirements. These air emission rules have the potential to increase our compliance costs. Compliance with these and other air pollution control and permitting requirements has the potential to delay the development of natural gas and oil projects and increase our costs of development and production, which costs could be significant. However, we do not believe that compliance with such requirements will have a material adverse effect on our operations.

Climate change. In response to findings that emissions of carbon dioxide, methane and other "greenhouse gases" ("GHGs") present an endangerment to public health and the environment, the EPA has issued regulations to restrict emissions of GHGs under existing provisions of the CAA. These regulations include limits on tailpipe emissions from motor vehicles and preconstruction and operating permit requirements for certain large stationary sources. The EPA has also adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, as well as certain onshore oil and natural gas production facilities, on an annual basis, including GHG emissions resulting from the completion and workover operations of hydraulically fractured oil wells. Recent federal regulatory action with respect to climate change has focused on methane emissions. As noted above, both the EPA and the BLM finalized rules in 2016 that limit methane emissions from upstream oil and gas exploration and production operations. Increased regulation of methane and other GHGs have the potential to result in increased compliance costs and, consequently, adversely affect our operations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce emissions of GHGs in recent years. In the absence of Congressional action, many states have established GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and natural gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances, or to comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Reduced demand for the oil and gas that we produce could also have the effect of lowering the value of our reserves. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

Hydraulic fracturing. Hydraulic fracturing is an important and common practice that is used to stimulate production of oil and/or natural gas from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing as part of our operations. The process is typically regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel and issued guidance in February 2014 governing such activities. The EPA has also issued final regulations under the CAA establishing performance standards, including standards for the capture of VOCs and methane released during hydraulic fracturing; an advanced notice of proposed rulemaking under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing; and final rules in June 2016 that prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. In addition, the BLM finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands. The U.S. District Court of Wyoming has temporarily stayed implementation of this rule. A final decision has not yet been issued.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. For example, New Mexico and Texas have adopted hydraulic fracturing fluid disclosure requirements, and the RRC has also adopted rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. In addition, local governments have also taken steps to regulate hydraulic fracturing, including imposing restrictions or moratoria on oil and gas activities occurring within their boundaries. If new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under some circumstances, noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. Since the report did not find a direct link between hydraulic fracturing itself and contamination of groundwater resources, this years-long study report does not appear to provide any basis for further regulation of hydraulic fracturing at the federal level.

We do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations; however, we believe our well control, general liability and excess liability insurance policies may cover third-party claims related to hydraulic fracturing operations and associated legal expenses in accordance with, and subject to, the terms of such policies. If new laws or regulations significantly restrict hydraulic fracturing activities or impose burdens on new permitting or operating requirements, our ability to utilize hydraulic fracturing may be curtailed, and this may in turn reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Operations on Federal Lands. We currently operate on federal lands under the jurisdiction of the BLM. Permitting for oil and gas activities on federal lands can take significantly longer than the state permitting process. Delays in obtaining permits necessary can disrupt our operations and have an adverse effect on our business. As noted above, in November 2016, the BLM finalized rules that restrict methane emissions from oil and gas activities on federal lands by limiting venting and flaring of natural gas from wells and other equipment. The final rule also requires operators to pay royalties to the BLM on flared gas from wells already connected to gas capture infrastructure, and allows the agency to set royalty rates at or above 12.5 percent of the value of production. These rules could result in increased compliance costs for our operations, which in turn could have an adverse effect on our business and results of operations.

Endangered species. The federal Endangered Species Act (the "ESA") and analogous state laws regulate activities that could have an adverse effect on threatened or endangered species. Some of our drilling operations are conducted in areas where protected species are known to exist. In these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts to protected species, and we may be prohibited from conducting drilling operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to drilling activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. The presence of a protected species in areas where we perform drilling activities could impair our ability to timely complete drilling and developmental operations and could adversely affect our future production from those areas. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on listing of numerous species as endangered or threatened under the ESA before the completion of the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where we or our oil and natural gas exploration and production customers operate could cause us or our customers to incur increased costs arising from species protection measures and could result in delays or limitations in our customers' performance of operations, which could reduce demand for our midstream services.

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay or even halt development of some of our oil and natural gas projects.

OSHA and other laws and regulations. We are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. Also, pursuant to OSHA, the Occupational Safety and Health Administration has established a variety of standards relating to workplace exposure to hazardous substances and employee health and safety.

We do not believe that compliance with existing environmental laws and regulations applicable to our current operations will have a material adverse impact on our financial condition and results of operations. For instance, we did not incur any material capital expenditures for remediation or pollution control activities during 2016. Additionally, as of the date of this report, we are not aware of any environmental issues or claims that will require material capital expenditures during 2017. However, we cannot assure you that the passage or application of more stringent laws or regulations in the future will not have a negative impact on our financial position or results of operations.

Our Employees

Our corporate headquarters are located at One Concho Center, 600 West Illinois Avenue, Midland, Texas 79701. We also maintain various field offices in Texas and New Mexico. At December 31, 2016, we had 1,085 employees, 392 of whom were employed in field operations. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be good. We also utilize the services of contractors to perform various field and other services.

Available Information

We file or furnish annual, quarterly and current reports, proxy statements and other documents with the United States Securities and Exchange Commission (the "SEC") under the Exchange Act. The public may read and copy any materials that we file or furnish with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains a website that contains reports, proxy and information statements, and other information regarding issuers, including us, that file or furnish electronically with the SEC. The public can obtain any documents that we file with the SEC at *www.sec.gov*.

We also make available free of charge through our website, *www.concho.com*, our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

Non-GAAP Financial Measure

Reconciliation of Net Income (Loss) to EBITDAX

EBITDAX (as defined below) is presented herein and reconciled from the GAAP measure of net income (loss) because of its wide acceptance by the investment community as a financial indicator of a company's ability to internally fund exploration and development activities.

We define EBITDAX as net income (loss), plus (1) exploration and abandonments expense, (2) depreciation, depletion and amortization expense, (3) accretion expense, (4) impairments of long-lived assets, (5) non-cash stock-based compensation expense, (6) (gain) loss on derivatives, (7) net cash receipts from (payments on) derivatives, (8) (gain) loss on disposition of assets, net, (9) interest expense, (10) loss on extinguishment of debt, (11) federal and state income tax expense (benefit) from continuing operations and (12) similar items listed above that are presented in discontinued operations. EBITDAX is not a measure of net income (loss) or cash flows as determined by GAAP.

Our EBITDAX measure provides additional information which may be used to better understand our operations, and it is also a material component of one of the financial covenants under our credit facility. EBITDAX is one of several metrics that we use as a supplemental financial measurement in the evaluation of our business and should not be considered as an alternative to, or more meaningful than, net income (loss) as an indicator of operating performance. Certain items excluded from EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic cost of depreciable and depletable assets. EBITDAX, as used by us, may not be comparable to similarly titled measures reported by other companies. We believe that EBITDAX is a widely followed measure of operating performance and is one of many metrics used by our management team and by other users of our consolidated financial statements, including by lenders pursuant to a covenant in our credit facility. For example, EBITDAX can be used to assess our operating performance and return on capital in comparison to other independent exploration and production companies without regard to financial or capital structure, and to assess the financial performance of our assets and our company without regard to capital structure or historical cost basis. Further, under our credit facility, an event of default could arise if we were not able to satisfy and remain in compliance with our specified financial ratio, defined as the maintenance of a quarterly ratio of total debt to consolidated last twelve months EBITDAX of no greater than 4.25 to 1.0. Non-compliance with this ratio could trigger an event of default under our credit facility, which then could trigger an event of default under our indentures. At December 31, 2016, we were in compliance with the covenants under all of our debt instruments.

The following table provides a reconciliation of the GAAP measure of net income (loss) to EBITDAX (non-GAAP) for the periods indicated:

	Years Ended December 31,				
(in thousands)	**2016**	**2015**	**2014**	**2013**	**2012**
Net income (loss)	$ (1,462,446)	$ 65,900	$ 538,175	$ 251,003	$ 431,689
Exploration and abandonments	77,454	58,847	284,821	109,549	39,840
Depreciation, depletion and amortization	1,167,208	1,223,253	979,740	772,608	575,128
Accretion of discount on asset retirement obligations	7,133	7,600	7,072	6,047	4,187
Impairments of long-lived assets	1,524,645	60,529	447,151	65,375	-
Non-cash stock-based compensation	58,927	63,073	47,130	35,078	29,872
(Gain) loss on derivatives	368,684	(699,752)	(890,917)	123,652	(127,443)
Net cash receipts from (payments on) derivatives	625,250	632,916	71,983	(32,341)	23,536
(Gain) loss on disposition of assets, net	(117,561)	53,789	9,308	1,268	372
Interest expense	203,518	215,384	216,661	218,581	182,705
Loss on extinguishment of debt	56,436	-	4,316	28,616	-
Income tax expense (benefit) from continuing operations	(876,090)	31,371	317,785	118,237	251,041
Discontinued operations	-	-	-	(12,081)	64,701
EBITDAX	$ 1,633,158	$ 1,712,910	$ 2,033,225	$ 1,685,592	$ 1,475,628

Item 1A. Risk Factors

You should consider carefully the following risk factors together with all of the other information included in this report and other reports filed with the SEC before investing in our securities. If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected. In that case, the trading price of our securities could decline and you could lose all or part of your investment.

Risks Related to Our Business

Oil, natural gas and natural gas liquid prices are volatile and continued to decline significantly during 2015, with sustained lower prices through 2016. An extended continuation of, or a further decline in, oil, natural gas and natural gas liquid prices could adversely affect our financial position, financial results, cash flow, access to capital and ability to grow.

Our future financial condition, revenues, results of operations, rate of growth and the carrying value of our oil and natural gas properties depend primarily upon the prices we receive for our oil and natural gas production and the prices prevailing from time to time for oil, natural gas and natural gas liquids. Oil, natural gas, and natural gas liquid prices historically have been volatile, and are likely to continue to be volatile in the future, especially given current geopolitical conditions. This price volatility also affects the amount of cash flow we have available for capital expenditures and our ability to borrow money or raise additional capital. The prices and levels of production for oil, natural gas and natural gas liquids are subject to a variety of factors beyond our control, including:

- the level of consumer demand for oil, natural gas and natural gas liquids;
- the domestic and foreign supply of oil, natural gas, and natural gas liquids;
- inventory levels of Cushing, Oklahoma, the benchmark for WTI oil prices;
- liquefied natural gas deliveries to and from the United States;
- commodity processing, gathering and transportation availability and the availability of refining capacity;
- the price and level of imports of foreign oil and natural gas;
- the ability of the members of the Organization of Petroleum Exporting Countries and other oil exporting nations to agree to and maintain oil price and production controls;
- domestic and foreign governmental regulations and taxes;
- the price and availability of alternative fuel sources;
- weather conditions;
- political conditions or hostilities in oil and natural gas producing regions, including the Middle East, Africa and South America;
- technological advances affecting energy consumption and energy supply;
- effect of energy conservation efforts;
- variations between product prices at sales points and applicable index prices; and
- worldwide economic conditions.

Furthermore, oil and natural gas prices continued to be volatile in 2016. For example, the NYMEX oil prices in 2016 ranged from a high of $54.06 to a low of $26.21 per Bbl and the NYMEX natural gas prices in 2016 ranged from a high of $3.93 to a low of $1.64 per MMBtu. Further, the NYMEX oil prices and NYMEX natural gas prices reached lows of $50.82 per Bbl and $2.83 per MMBtu, respectively, during the period from January 1, 2017 to February 17, 2017.

Declines in oil, natural gas and natural gas liquid prices would not only reduce our revenue, but could also reduce the amount of oil and natural gas that we can produce economically. This in turn would lower the amount of oil and natural gas reserves we could recognize and, as a result, could have a material adverse effect on our financial condition and results of operations. If the oil and natural gas industry continues to experience significant price declines, we may, among other things, be unable to maintain or increase our borrowing capacity, repay current or future indebtedness or obtain additional capital on attractive terms, all of which can adversely affect the value of our securities.

Approximately 35.3 percent of our total estimated proved reserves at December 31, 2016 were undeveloped, and those reserves may not ultimately be developed.

At December 31, 2016, approximately 35.3 percent of our total estimated proved reserves were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling. Our reserve data assumes that we can and will make these expenditures and conduct these operations successfully. These assumptions, however, may not prove correct. Our reserve report at December 31, 2016 includes estimates of total future development costs over the next five years associated with our proved undeveloped reserves of approximately $2.1 billion. If we choose not to spend the capital to develop these reserves, or if we are not otherwise able to successfully develop these reserves, we will be required to write-off these reserves. In addition, under the SEC's reserve rules, because proved undeveloped reserves may be booked only if they relate to wells planned to be drilled within five years of the date of booking, we may be required to write-off any proved undeveloped reserves that are not developed within this five-year timeframe. For example, as of December 31, 2016, we wrote-off approximately 57.4 MMBoe of proved undeveloped reserves because they are no longer expected to be developed within five years of their initial recording. Any such write-offs of our reserves could reduce our ability to borrow money and could reduce the value of our securities.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that could cause our costs to increase or production volumes to decrease, which would reduce our cash flows.

Our future financial condition and results of operations will depend on the success of our exploration and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Our cost of drilling, completing, equipping and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical or less economical than forecasted. Further, many factors may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory and contractual requirements;
- reductions in oil, natural gas and natural gas liquid prices;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel or in obtaining water for hydraulic fracturing activities;
- equipment failures or accidents;
- adverse weather conditions;
- political events, public protests, civil disturbances, terrorist acts or cyber attacks;
- environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- limited availability of financing at acceptable terms;
- surface access restrictions;

- loss of title or other title related issues;

- oil, natural gas liquids or natural gas gathering, transportation and processing availability restrictions or limitations; and

- limitations in the market for oil, natural gas and natural gas liquids.

Prolonged decreases in our drilling program may require us to pay certain non-use fees or impact our ability to comply with certain contractual requirements.

Oil prices declined substantially during the second half of 2014 and continued to decline through 2015 with sustained lower prices through 2016. In the event that oil and natural gas prices remain depressed for a sustained period, or continue to further decline, we may experience significant decreases in drilling activity. Due to the nature of our drilling programs and the oil and natural gas industry generally, we are a party to certain agreements that require us to meet various contractual obligations or require us to utilize a certain amount of goods or services, including, but not limited to, water commitments, throughput volume commitments, power commitments and drilling commitments. In the event that oil and natural gas prices remain depressed, and as a result continue to reduce the demand for drilling and production, this could lead to a decrease in our drilling activity and production levels, which could, in turn, require us to pay for unutilized goods or services or impact our ability to meet these contractual obligations.

We may incur losses as a result of title defects in our oil and natural gas properties.

It is our practice to initially conduct only a cursory title review of the oil and natural gas properties on which we do not have proved reserves. To the extent title opinions or other investigations prior to our commencement of drilling operations reflect defects affecting such properties, we are typically responsible for curing any such defects at our expense. Additionally, the discovery of any such defects could delay or prohibit the commencement of drilling operations on the affected properties. These impacts and other potential losses resulting from title defects in our oil and natural gas properties could have a material adverse effect on our business, financial condition and results of operations.

Federal, state and local legislation and regulatory initiatives relating to hydraulic fracturing, as well as governmental reviews of such activities, could result in increased costs and additional operating restrictions or delays and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. We routinely utilize hydraulic fracturing techniques in many of our drilling and completion programs. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and natural gas commissions. However, the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the SDWA's Underground Injection Control Program and issued guidance in February 2014, governing such activities. The EPA has also issued: final regulations under the CAA establishing performance standards, including standards for the capture of VOCs and methane released during hydraulic fracturing; an advanced notice of proposed rulemaking under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing; and final rules in June 2016 to prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. In addition, the BLM finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands. The United States District Court of Wyoming has temporarily stayed implementation of this rule. A final decision has not yet been issued.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. For example, New Mexico and Texas have adopted hydraulic fracturing fluid disclosure requirements, and the RRC has also adopted rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. In addition, local governments have also taken steps to regulate hydraulic fracturing, including imposing restrictions or moratoria on oil and gas activities occurring within their boundaries. If new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under some circumstances, noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. Since the report did not find a direct link between hydraulic fracturing itself and contamination of groundwater resources, this years-long study report does not appear to provide any basis for further regulation of hydraulic fracturing at the federal level.

If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, our fracturing activities could become subject to additional permitting requirements and could also result in permitting delays and potential cost increases. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.

Water is an essential component of both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local land owners and other sources for use in our operations. Over the past few years, extreme drought conditions persisted in West Texas and Southeast New Mexico. Although conditions have improved, we cannot guarantee what conditions may occur in the future. Severe drought conditions can result in local water districts taking steps to restrict the use of water subject to their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil and natural gas, which could have an adverse effect on our financial condition, results of operations and cash flows.

Estimates of proved reserves and future net cash flows are not precise. The actual quantities of our proved reserves and our future net cash flows may prove to be lower than estimated.

Numerous uncertainties exist in estimating quantities of proved reserves and future net cash flows therefrom. Our estimates of proved reserves and related future net cash flows are based on various assumptions, which may ultimately prove to be inaccurate.

Petroleum engineering is a subjective process of estimating accumulations of oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including the following:

- historical production from the area compared with production from other producing areas;
- the assumed effects of regulations by governmental agencies;
- the quality, quantity and interpretation of available relevant data;
- assumptions concerning future commodity prices; and
- assumptions concerning future operating costs; severance, ad valorem and excise taxes; development costs; and workover and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items, or other items not identified below, may differ materially from those assumed in estimating reserves:

- the quantities of oil and natural gas that are ultimately recovered;
- the production and operating costs incurred;

- the amount and timing of future development expenditures; and
- future commodity prices.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same data. Our actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material.

As required by the SEC, the estimated discounted future net cash flows from proved reserves are based on the average previous twelve months first-of-month prices preceding the date of the estimate and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as:

- the amount and timing of actual production;
- levels of future capital spending;
- increases or decreases in the supply of or demand for oil, natural gas liquids and natural gas; and
- changes in governmental regulations or taxation.

Accordingly, estimates included herein of future net cash flows may be materially different from the future net cash flows that are ultimately received. Therefore, the estimates of discounted future net cash flows in this report should not be construed as accurate estimates of the current market value of our proved reserves.

Our business requires substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a decline in our oil and natural gas reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the acquisition, exploration and development of oil and natural gas reserves. At December 31, 2016, we had no outstanding debt under our credit facility (and total debt at December 31, 2016 was $2.7 billion), and we had approximately $2.5 billion of unused commitments under our credit facility. Expenditures for acquisition, exploration and development of oil and natural gas properties are the primary use of our capital resources. We incurred approximately $3.3 billion in acquisition, exploration and development activities (excluding asset retirement obligations) during the year ended December 31, 2016. In February 2017, we announced our updated 2017 capital budget, excluding acquisitions, of approximately $1.8 billion with expected capital spending to range between $1.6 billion and $1.8 billion. Approximately 90 percent of capital will be directed to drilling and completion activity. Our 2017 capital program is expected to continue focusing on extended length lateral drilling. Our 2017 capital budget, based on our current expectations of commodity prices and costs, is expected to be within our cash flows. Our budget could change depending on numerous factors, including commodity prices, leverage metrics and industry conditions. We plan to spend approximately $2.1 billion over the next five years on future development costs associated with proved undeveloped reserves.

We intend to finance our future capital expenditures, other than significant acquisitions, through cash flow from operations and through borrowings under our credit facility; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities. The issuance of additional equity securities could have a dilutive effect on the value of our common stock. Additional borrowings under our credit facility or the issuance of additional debt securities will require that a greater portion of our cash flow from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flow to fund working capital, capital expenditures and acquisitions. In addition, our credit facility imposes certain limitations on our ability to incur additional indebtedness other than indebtedness under our credit facility. If we desire to issue additional debt securities other than as expressly permitted under our credit facility, we will be required to seek the consent of the lenders in accordance with the requirements of the credit facility, which consent may be withheld by the lenders at their discretion. If we incur certain additional indebtedness, our borrowing base under our credit facility may be reduced. Additional financing also may not be available on acceptable terms or at all. In the event additional capital resources are unavailable, we may curtail drilling, development and other activities or be forced to sell some of our assets on an untimely or unfavorable basis.

Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;

- the level of oil and natural gas we are able to produce from existing wells;
- the prices at which our commodities are sold;
- the costs of producing oil and natural gas;
- global credit and securities markets;
- the ability and willingness of lenders and investors to provide capital and the cost of the capital;
- our ability to acquire, locate and produce new reserves; and
- the impact of potential changes in our credit ratings.

If our revenues or the borrowing base under our credit facility decrease as a result of lower commodity prices or sustained depressed commodity prices, operating difficulties, declines in reserves, lending requirements or regulations, or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current or anticipated levels. As a result, we may require additional capital to fund our operations, and we may not be able to obtain debt or equity financing on terms acceptable to us, if at all, to satisfy our capital requirements. If cash generated from operations or borrowings available under our credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to the development of our prospects, which in turn could lead to a decline in our oil and natural gas reserves, and could adversely affect our production, revenues and results of operations.

Declining general economic, business or industry conditions could have a material adverse effect on our results of operations.

In recent years, the global economic downturn, particularly with respect to the U.S. economy, and the global financial and credit market disruptions have reduced the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide resulting in a slowdown in economic activity. This has reduced worldwide demand for energy and resulted in lower commodity prices.

Lower commodity prices will reduce our cash flows and borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our reserves as existing reserves are depleted. Lower commodity prices may also reduce the amount of oil and natural gas that we can produce economically, which could ultimately decrease our net revenue and profitability.

Our ability to use our net operating loss carryforwards or other tax attributes could be limited.

We generated a $477.7 million net operating loss ("NOL") in 2016. Utilization of this NOL depends on many factors, including our ability to generate future taxable income, which cannot be assured. In addition, Section 382 of the Internal Revenue Code of 1986, as amended ("Section 382"), generally imposes an annual limitation on the amount of NOLs that may be used to offset taxable income when a corporation has undergone an "ownership change" (as determined under Section 382). An ownership change generally occurs if one or more stockholders (or groups of stockholders) who are each deemed to own at least five percent of our stock change their ownership by more than 50 percentage points over their lowest ownership percentage within a rolling three-year period. In the event that an ownership change has occurred, or were to occur, utilization of our NOLs would be subject to an annual limitation under Section 382, determined by multiplying the value of our equity at the time of the ownership change by the applicable long-term tax-exempt rate as defined in Section 382, and potentially increased for certain gains recognized within five years after the ownership change if we have a net built-in gain in our assets at the time of the ownership change. Any unused annual limitation may be carried over to later years. We do not believe that an ownership change has occurred as a result of our recent equity offerings or our issuance of shares in connection with various acquisitions. As such, Section 382 was not expected to limit our ability to utilize our NOL carryforward or any other tax attribute as of December 31, 2016. Future ownership changes or future regulatory changes could limit our ability to utilize our NOLs. To the extent we are not able to offset our future income with our NOLs, this could adversely affect our operating results and cash flows once we attain profitability.

We have substantial indebtedness and may incur substantially more debt. Higher levels of indebtedness make us more vulnerable to economic downturns and adverse developments in our business.

We had approximately $2.7 billion of outstanding debt at December 31, 2016. At December 31, 2016, the borrowing base under our credit facility was $2.8 billion and commitments from our bank group were $2.5 billion, of which $2.5 billion was unused commitments.

As a result of our indebtedness, we will need to use a portion of our cash flow to pay interest, which will reduce the amount we will have available to fund our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate. Our indebtedness under our credit facility is at a variable interest rate, and so a rise in interest rates will generate greater interest expense to the extent we do not have applicable interest rate fluctuation hedges. The amount of our debt may also cause us to be more vulnerable to economic downturns and adverse developments in our business.

We may incur substantially more debt in the future. The indentures governing our senior notes contain restrictions on our incurrence of additional indebtedness. These restrictions, however, are subject to a number of qualifications and exceptions, and under certain circumstances, we could incur substantial additional indebtedness in compliance with these restrictions. Moreover, these restrictions do not prevent us from incurring obligations that do not constitute indebtedness under the indentures.

Any increase in our level of indebtedness could have adverse effects on our financial condition and results of operations, including imposing additional cash requirements on us in order to support interest payments, increasing our vulnerability to adverse changes in general economic and industry conditions and limiting our ability to obtain additional financing for working capital, capital expenditures, general corporate and other purposes.

If we are unable to comply with the restrictions and covenants in the agreements governing our indebtedness, there could be a default under the terms of these agreements, which could result in an acceleration of payment of funds that we have borrowed.

Our ability to meet our debt obligations and other expenses will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors, many of which we are unable to control. If our cash flow is not sufficient to service our debt, we may be required to refinance debt, sell assets or sell additional equity on terms that we may not find attractive if it may be done at all. If we are unable to generate sufficient cash flow and are otherwise unable to obtain funds necessary to meet required payments of principal, premium, if any, and interest, if any, on our indebtedness, or if we otherwise fail to comply with the various covenants, including financial and operating covenants, in the agreements governing our indebtedness, we could be in default under the terms of the agreements governing such indebtedness. In the event of such default:

- the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest;
- the lenders under our credit facility could elect to terminate their commitments thereunder, cease making further loans and institute foreclosure proceedings against our assets; and
- we could be forced into bankruptcy or liquidation.

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

Our lenders can limit our borrowing capabilities, which may materially impact our operations.

At December 31, 2016, we had no debt outstanding under our credit facility, and our borrowing base was $2.8 billion and commitments from our bank group were $2.5 billion. The borrowing base under our credit facility is redetermined annually based upon a number of factors, including commodity prices and reserve levels. In addition, between redeterminations we and, if requested by 66 2/3 percent of our lenders, our lenders, may each request one special redetermination. Upon a redetermination, our borrowing base could be substantially reduced, and in the event the amount outstanding under our credit facility at any time exceeds the borrowing base at such time, we may be required to repay a portion of our outstanding borrowings. We expect to utilize cash on hand, cash flow from operations, bank borrowings, debt and equity financings and asset sales to fund our acquisition, exploration and development activities. A reduction in our borrowing base could limit our activities. In addition, we may significantly alter our capitalization in order to make future acquisitions or develop our properties. These changes in capitalization may significantly increase our level of indebtedness. If we incur additional debt for these or other purposes, the related risks that we now face could intensify. A higher level of indebtedness also increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance which is affected by general economic conditions and financial, business and other factors, many of which are beyond our control.

A downgrade in our credit rating could negatively impact our cost of and ability to access capital.

We receive debt credit ratings from S&P Global Ratings ("S&P") and Moody's Investors Service, Inc. ("Moody's"), which are subject to regular reviews. At December 31, 2016, our long-term debt was rated "BB+" by S&P with an outlook that was raised from stable to positive in August 2016. Moody's corporate rating for us is "Ba1" with a stable outlook. S&P and Moody's consider many factors in determining our ratings including: the industry in which we operate, production growth opportunities, liquidity, debt levels and asset and reserve mix. A reduction in our debt ratings could negatively affect our ability to obtain financing or the interest rate, fees and other terms associated with such additional financing.

A downgrade in our credit ratings could negatively impact our costs of capital and our ability to effectively execute aspects of our strategy. Further, a downgrade in our credit ratings could affect our ability to raise debt in the public debt markets, and the cost of any new debt could be much higher than our outstanding debt. These and other impacts of a downgrade in our credit ratings could have a material adverse effect on our business, financial condition and results of operations.

As of the filing of this report, no additional changes in our credit ratings have occurred; however, we cannot be assured that our credit ratings will not be downgraded in the future.

Our operations expose us to significant costs and liabilities with respect to environmental and operational safety matters.

We may incur significant delays, costs and liabilities as a result of environmental, occupational health and safety requirements applicable to our oil and natural gas exploration, development and production, and related saltwater disposal activities. These delays, costs and liabilities could arise under a wide range of federal, state and local laws and regulations relating to protection of the environment, occupational health and safety, including regulations and enforcement policies that have tended to become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations.

Strict as well as joint and several liability for a variety of environmental costs may be imposed on us under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. New laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. No assurance can be given that continued compliance with existing or future environmental laws and regulations will not result in a curtailment of production or processing activities or result in a material increase in the costs of production, development, exploration or processing operations. If we are not able to recover the resulting costs through insurance or increased revenues, our production, revenues and results of operations could be adversely affected.

Our producing properties are concentrated in the Permian Basin of Southeast New Mexico and West Texas, making us vulnerable to risks associated with operating in one major geographic area. In addition, we have a large amount of proved reserves attributable to a small number of producing horizons within this area.

Our producing properties are geographically concentrated in the Permian Basin of Southeast New Mexico and West Texas. At December 31, 2016, substantially all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, severe weather events, water shortages or other drought related conditions or interruption of the processing or transportation of oil, natural gas or natural gas liquids.

In addition to the geographic concentration of our producing properties described above, at December 31, 2016, approximately: (i) 32 percent of our proved reserves were attributable to the Avalon Shale, Bone Spring and Wolfcamp formations located in the Northern Delaware Basin; (ii) 15 percent of our proved reserves were attributable to the Bone Spring and Wolfcamp formations located in the Southern Delaware Basin; (iii) 26 percent of our proved reserves were attributable to the Wolfcamp and Spraberry formations in the Midland Basin; and (iv) 24 percent of our proved reserves were attributable to the Yeso formation, which includes both the Paddock and Blinebry intervals, underlying our oil and natural gas properties located in Southeast New Mexico. This concentration of assets within a small number of producing horizons exposes us to additional risks, such as changes in field-wide rules and regulations that could cause us to permanently or temporarily shut-in all of our wells within a field.

We periodically assess our unproved oil and natural gas properties for impairment and could be required to recognize non-cash charges to earnings of future periods.

At December 31, 2016, we carried unproved property costs of $1.9 billion. GAAP requires periodic assessment of these costs on a project-by-project basis. Our assessment considers future drilling and exploration plans, results of exploration activities, commodity price outlooks, planned future sales, expiration of all or a portion of the projects, contracts and permits relevant to such projects. Based on our assessments, we may determine that we are unable to fully recover the cost invested in each project, and we will recognize non-cash charges to earnings in future periods if such determination is made.

Future price declines could result in a reduction in the carrying value of our proved oil and natural gas properties, which could adversely affect our results of operations.

Declines in commodity prices may result in us having to make substantial downward adjustments to the value of our estimated proved reserves. If this occurs, or if our estimates of production or economic factors change, accounting rules may require us to write-down, as a non-cash charge to earnings, the carrying value of our proved oil and natural gas properties for impairments. We are required to perform impairment tests on proved assets whenever events or changes in circumstances warrant a review of our proved oil and natural gas properties. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our oil and natural gas properties, the carrying value may not be recoverable and therefore require a write-down. The primary factors that may affect management's estimates of future cash flows are (i) commodity futures prices, (ii) increases or decreases in production and capital costs, (iii) future reserve volume adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves, (iv) results of future drilling activities and (v) prevailing market rates of income and expenses from integrated assets. We may incur impairment charges in the future, which could materially adversely affect our results of operations in the period incurred. We estimate that if the oil and natural gas prices used in this analysis would have been approximately 10 percent lower as of December 31, 2016 with no other changes in capital costs, operating costs, price differentials, or reserve volumes, no impairment would be indicated.

Other assumptions such as operating costs, well and reservoir performance, severance and ad valorem taxes, and operating and development plans would likely change given a change in oil and natural gas prices. However, we are unable to estimate the correlation between these assumptions and any estimated commodity price change, and these and other assumptions may worsen or partially mitigate some of the effects of a reduction in commodity prices, including the ultimate impact and amount of any potential impairment charge.

Part of our strategy involves exploratory drilling, including drilling in new or emerging plays. As a result, our drilling results in these areas are uncertain, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

The results of our exploratory drilling in new or emerging plays are more uncertain than drilling results in areas that are developed and have established production. Since new or emerging plays and new formations have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. As a result, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

Our commodity price risk management program may cause us to forego additional future profits or result in our making cash payments to our counterparties.

To reduce our exposure to changes in the prices of commodities, we have entered into and may in the future enter into additional commodity price risk management arrangements for a portion of our oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Commodity price risk management arrangements expose us to the risk of financial loss and may limit our ability to benefit from increases in commodity prices in some circumstances, including the following:

- the counterparty to a commodity price risk management contract may default on its contractual obligations to us;
- there may be a change in the expected differential between the underlying price in a commodity price risk management agreement and actual prices received; or
- market prices may exceed the prices which we are contracted to receive, resulting in our need to make significant cash payments to our counterparties.

Our commodity price risk management activities could have the effect of reducing our net income and the value of our securities. At December 31, 2016, we had a net derivative liability of approximately $174.4 million. An average increase in the commodity price of $5.00 per barrel of oil and $0.50 per MMBtu for natural gas from the commodity price at December 31, 2016 would have resulted in an increase in our net liability of approximately $249.6 million. We may continue to incur significant gains or losses in the future from our commodity price risk management activities to the extent market prices increase or decrease and our derivatives contracts remain in place.

Our identified inventory of drilling locations and recompletion opportunities are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

We have identified and scheduled the drilling of certain locations as an estimation of our future multi-year development activities on our existing acreage. These identified locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including: (i) our ability to timely drill wells on lands subject to complex development terms and circumstances; (ii) the availability of capital, equipment, services and qualified personnel; (iii) weather conditions; (iv) regulatory and third-party approvals; (v) commodity prices; (vi) access to and availability of water sourcing and distribution systems; and (vii) drilling and recompletion costs and results. Additionally, changes in the laws or regulations on which we rely in planning and executing our drilling programs could adversely impact our ability to successfully complete those programs. Because of these and other potential uncertainties, we may never drill the potential locations we have identified or produce oil or natural gas from these or any other potential locations. As such, our actual development activities may materially differ from those presently identified, which could adversely affect our production, revenues and results of operations.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our cash flow, our ability to raise capital and the value of our securities.

Unless we conduct successful development and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and therefore our cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. The value of our securities and our ability to raise capital will be adversely impacted if we are not able to replace our reserves that are depleted by production. We may not be able to develop, exploit, find or acquire sufficient additional reserves to replace our current and future production.

The Standardized Measure of our estimated reserves is not an accurate estimate of the current fair value of our estimated proved oil and natural gas reserves.

Standardized Measure is a reporting convention that provides a common basis for comparing oil and natural gas companies subject to the rules and regulations of the SEC. This measure requires the use of operating and development costs prevailing as of the date of computation. Consequently, it will not reflect the prices ordinarily received or that will be received for oil and natural gas production because of varying market conditions, nor may it reflect the actual costs that will be required to produce or develop the oil and natural gas properties. Accordingly, estimates included herein of future net cash flows may be materially different from the future net cash flows that are ultimately received. In addition, the 10 percent discount factor, which is required by the rules and regulations of the SEC to be used in calculating discounted future net cash flows for reporting purposes, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our company or the oil and natural gas industry in general. Therefore, Standardized Measure included in this report should not be construed as an accurate estimate of the current fair value of our proved reserves.

Our reserve estimates and our computation of future net cash flows are based on SEC pricing of (i) $39.25 per Bbl WTI posted oil price and (ii) $2.48 per MMBtu Henry Hub spot natural gas price, adjusted for location and quality by property. The SEC pricing for reserves as of December 31, 2016 is lower than the NYMEX oil price and NYMEX natural gas price of $53.40 per Bbl and $2.83 per MMBtu, respectively, at February 17, 2017. If average oil prices were $5.00 per barrel lower than the average price we used, our proved reserves at December 31, 2016 would have decreased from 720.0 MMBoe to 705.7 MMBoe. If average natural gas prices were $0.50 per MMBtu lower than the average price we used, our proved reserves at December 31, 2016 would have decreased from 720.0 MMBoe to 709.8 MMBoe. Any adjustments to the estimates of proved reserves or decreases in the price of our commodities may decrease the value of our securities.

We may be unable to make attractive acquisitions or successfully integrate acquired companies or assets, and any inability to do so may disrupt our business and hinder our ability to grow.

One aspect of our business strategy calls for acquisitions of businesses or assets that complement or expand our current business. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive candidates, we may not be able to complete the acquisition of them or do so on commercially acceptable terms.

In addition, our credit facility and the indentures governing our senior notes impose certain limitations on our ability to enter into mergers or combination transactions. Our credit facility and the indentures governing our senior notes also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses or assets. If we desire to engage in an acquisition that is otherwise prohibited by our credit facility or the indentures governing our senior notes, we will be required to seek the consent of our lenders or the holders of the senior notes in accordance with the requirements of the credit facility or the indentures, which consent may be withheld by the lenders under our credit facility or such holders of senior notes at their sole discretion.

If we acquire another business or assets, we could have difficulty integrating its operations, systems, management and other personnel and technology with our own. These difficulties could disrupt our ongoing business, distract our management and employees, increase our expenses and adversely affect our results of operations. In addition, we may incur additional debt or issue additional equity to pay for any future acquisitions, subject to the limitations described above.

Any acquisition we complete is subject to substantial risks that could adversely affect our business, including the risk that our acquisitions may prove to be worth less than what we paid because of uncertainties in evaluating recoverable reserves and could expose us to potentially significant liabilities.

We obtained a significant portion of our current reserve base through acquisitions of producing properties and undeveloped acreage. We expect that acquisitions will continue to contribute to our future growth. In connection with these and potential future acquisitions, we are often only able to perform limited due diligence. The success of any acquisition involves potential risks, including among other things:

- the inability to estimate accurately the costs to develop the reserves, recoverable volumes of reserves, rates of future production and future net cash flows attainable from the reserves;
- the assumption of unknown liabilities, including environmental liabilities, and losses or costs for which we are not indemnified or for which the indemnity we receive is inadequate;
- the effect on our liquidity or financial leverage of using available cash or debt to finance acquisitions;
- the diversion of management’s attention from other business concerns; and
- an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets.

Successful acquisitions of oil and natural gas properties require an assessment of a number of factors, including estimates of recoverable reserves, the timing of recovering reserves, exploration potential, future commodity prices, operating costs and potential environmental, regulatory and other liabilities. Such assessments are inexact, and we cannot make these assessments with a high degree of accuracy. In connection with our assessments, we perform a review of the acquired properties that we believe to be generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise.

There may be threatened, contemplated, asserted or other claims against the acquired assets related to environmental, title, regulatory, tax, contract, litigation or other matters of which we are unaware, which could materially and adversely affect our production, revenues and results of operations. We are sometimes able to obtain contractual indemnification for preclosing liabilities, including environmental liabilities, but we generally acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. In addition, even when we are able to obtain such indemnification from the sellers, these indemnification obligations usually expire over time and expose us to potential unindemnified liabilities, which could materially adversely affect our production, revenues and results of operations.

Shortages of oilfield equipment, services and qualified personnel could delay our drilling program and increase the prices we pay to obtain such equipment, services and personnel.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with commodity prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other oilfield 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. Higher commodity prices generally stimulate demand and result in increased prices for drilling and workover rigs, crews and associated supplies, equipment and services. It is beyond our control and ability to predict whether these conditions will exist in the future and, if so, what their timing and duration will be. These types of shortages or price increases would decrease our profit margin, cash flow and operating results, or restrict our ability to drill the wells and conduct the operations which we currently have planned and budgeted or which we may plan in the future.

Our exploration and development drilling may not result in commercially productive reserves.

Drilling activities are subject to many risks, including the risk that commercially productive reservoirs will not be encountered. New wells that we drill may not be productive, or we may not recover all or any portion of our investment in such wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or natural gas is present or may be produced economically. Drilling for oil and natural gas often involves unprofitable results, not only from dry holes but also from wells that are productive but do not produce sufficient net reserves to return a profit at then realized prices 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;
- fracture stimulation accidents or failures;
- adverse weather conditions;
- compliance with environmental and other governmental or contractual requirements; and
- increases in the cost of, or shortages or delays in the availability of, electricity, water, supplies, materials, drilling or workover rigs, equipment and services.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations. In addition, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities, including well stimulation and completion activities such as hydraulic fracturing, are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater contamination;
- abnormally pressured or structured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- blowouts, cratering, fires, explosions and ruptures of pipelines;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- injury or loss of life;
- damage to and destruction of property and equipment;
- damage to natural resources due to underground migration of hydraulic fracturing fluids;
- pollution and other environmental damage, including spillage or mishandling of recovered hydraulic fracturing fluids;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not covered or not fully covered by insurance could have a material adverse effect on our production, revenues and results of operations.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil and natural gas and secure trained personnel.

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Some of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, those companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel may increase substantially in the future. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital. Our failure to acquire properties, market oil and natural gas and secure trained personnel and adequately compensate personnel could have a material adverse effect on our production, revenues and results of operations.

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

Market conditions or the unavailability of satisfactory oil and natural gas processing or transportation arrangements may hinder our access to oil, natural gas and natural gas liquid markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil, natural gas and natural gas liquids, the proximity of reserves to pipelines and terminal facilities, competition for such facilities and the inability of such facilities to gather, transport or process our production due to shutdowns or curtailments arising from mechanical, operational or weather related matters, including hurricanes and other severe weather conditions. Our ability to market our production depends in substantial part on the availability and capacity of gathering and transportation systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could have a material adverse effect on our business, financial condition and results of operations. We may be required to shut in or otherwise curtail production from wells due to lack of a market or inadequacy or unavailability of oil, natural gas liquid or natural gas pipeline or gathering, transportation or processing capacity. If that were to occur, then we would be unable to realize revenue from those wells until suitable arrangements were made to market our production.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, timing, manner or feasibility of conducting our operations or that may subject us to fines or penalties for any failure to comply.

Our oil and natural gas exploration, development and production, and related saltwater disposal operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state, local and governmental authorities. We may incur substantial costs and experience delays in order to maintain compliance with these existing laws and regulations. If we fail to comply with the existing laws and regulations, we may incur additional costs, including fines and penalties, in order to come back into compliance. In addition, our costs of compliance may increase or our operations may be otherwise adversely affected if existing laws and regulations are revised or reinterpreted or if the government agencies responsible for enforcing certain existing laws and regulations applicable to us change their priorities or policies, or if new laws and regulations become applicable to our operations. These and other costs could have a material adverse effect on our production, revenues and results of operations.

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

In past years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including to certain key U.S. federal income tax provisions currently available to oil and gas companies. Such legislative changes have included, but not been limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities and (iv) an extension of the amortization period for certain geological and geophysical expenditures. The new President and certain members of Congress are calling for U.S. federal tax reform, and Congress could consider, and could include, some or all of these proposals as part of tax reform legislation, to accompany lower federal income tax rates. Moreover, other more general features of tax reform legislation, including changes to cost recovery rules and to the deductibility of interest expense, may be developed that also would change the taxation of oil and gas companies. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could take effect. The passage of any legislation as a result of these proposals or any similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that currently are available with respect to oil and gas development, or increase costs, and any such changes could have an adverse effect on our financial position, results of operations and cash flows.

Climate change legislation or regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the crude oil and natural gas that we produce.

In response to findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment, the EPA has issued regulations to restrict emissions of GHGs under existing provisions of the CAA. These regulations include limits on tailpipe emissions from motor vehicles and preconstruction and operating permit requirements for certain large stationary sources. The EPA has also adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, as well as certain onshore oil and natural gas production facilities, on an annual basis, including GHG emissions resulting from the completion and workover operations of hydraulically fractured oil wells. Recent federal regulatory action with respect to climate change has focused on methane emissions. For example, in June 2016, the EPA finalized new air emission controls for emissions of methane from certain equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities. The final rule package includes first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions, and also imposes leak detection and repair requirements on operators. The BLM finalized similar rules in November 2016 that limit methane emissions from new and existing oil and gas operations on federal lands through limitations on the venting and flaring of gas, as well as enhanced leak detection and repair requirements. The BLM adopted the final rules in January 2017; however, operators generally have one year from the January 2017 effective date to come into compliance with the rule's requirements. These methane emission rules have the potential to increase our compliance costs.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce emissions of GHGs in recent years. In the absence of Congressional action, many states have established GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and natural gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or to comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Reduced demand for the oil and gas that we produce could also have the effect of lowering the value of our reserves. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

The adoption of derivatives legislation by Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, including us, which participate in that market. This legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Act"), became law on July 21, 2010 and requires the Commodities Futures Trading Commission (the "CFTC") and the SEC to promulgate rules and regulations implementing the Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The initial position limits rule was vacated by the United States District Court for the District of Columbia in September 2012. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and the associated rules also will require us, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or take steps to qualify for an exemption to such requirements. The CFTC has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing. Although we expect to qualify for the end-user exception from the mandatory clearing requirements for swaps entered to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. If our swaps do not qualify for the commercial end-user exception, or if the cost of entering into uncleared swaps becomes prohibitive, we may be required to clear such transactions. The ultimate effect of the rules and any additional regulations on our business is uncertain at this time.

In addition, certain banking regulators and the CFTC have adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to qualify for the end-user exception from such margin requirements for swaps entered into to hedge our commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, the posting of collateral could reduce our liquidity and cash available for capital expenditures and our ability to manage commodity price volatility and the volatility in cash flows. The impact of those provisions is uncertain at this time.

The full impact of the Act and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. The Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, or reduce our ability to monetize or restructure our existing derivative contracts. If we reduce our use of derivatives as a result of the Act and regulations implementing the Act, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Act was intended, in part, to reduce the volatility of commodity prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil, natural gas and natural gas liquids. Our revenues could therefore be adversely affected if a consequence of the Act and implementing regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

The loss of our chief executive officer or other key personnel could negatively impact our ability to execute our business strategy.

We depend, and will continue to depend in the foreseeable future, on the services of our chief executive officer, Timothy A. Leach, and other officers and key employees who have extensive experience and expertise in evaluating and analyzing producing oil and natural gas properties and drilling prospects, maximizing production from oil and natural gas properties, marketing oil and natural gas production, and developing and executing acquisition, financing and hedging strategies. Our ability to hire and retain our officers and key employees is important to our continued success and growth. The unexpected loss of the services of one or more of these individuals could negatively impact our ability to execute our business strategy.

Because we do not operate and therefore control the development of certain of the properties in which we own interests, we may not be able to produce economic quantities of oil and natural gas in a timely manner.

At December 31, 2016, approximately 8.3 percent of our proved reserves were attributable to properties for which we were not the operator. As a result, the success and timing of drilling and development activities on properties operated by others depend upon a number of factors, including:

- the nature and timing of drilling and operational activities;
- the timing and amount of capital expenditures;
- the operators' expertise and financial resources;
- the approval of other participants in such properties; and
- the selection and application of suitable technology.

If drilling and development activities are not conducted on these properties or are not conducted on a timely basis, we may be unable to increase our production or offset normal production declines or we will be required to write-off the reserves attributable thereto, which may adversely affect our production, revenues and results of operations. Any such write-offs of our reserves could reduce our ability to borrow money and could reduce the value of our securities.

Uncertainties associated with enhanced recovery methods may result in us not realizing an acceptable return on our investments in such projects.

We inject water into formations on some of our properties to increase the production of oil and natural gas. We may in the future expand these efforts to more of our properties or employ other enhanced recovery methods in our operations. The additional production and reserves, if any, attributable to the use of enhanced recovery methods are inherently difficult to predict. If our enhanced recovery methods do not allow for the extraction of oil and natural gas in a manner or to the extent that we anticipate, we may not realize an acceptable return on our investments in such projects.

Part of our strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Our operations involve utilizing some of the latest drilling and completion techniques. Risks that we face while drilling horizontal wells include, but are not limited to, the following:

- landing the wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running casing the entire length of the wellbore; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

Risks that we face while completing wells include, but are not limited to, the following:

- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

A terrorist or cyber-attack or armed conflict could harm our business by decreasing our revenues and increasing our costs.

Terrorist activities, anti-terrorist efforts, cyber-attacks and other armed conflict involving the United States may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur or escalate, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on demand for our production and causing a reduction in our revenue. Oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if significant infrastructure or facilities used for the production, transportation, processing or marketing of oil and natural gas production are destroyed or damaged. Additionally, as an oil and natural gas producer, we constantly face various cybersecurity threats, including threats to gain unauthorized access to sensitive information or to render data or systems unusable, and there can be no assurance that our implementation of various procedures and controls to monitor and mitigate security threats will be sufficient to prevent security breaches from occurring. Costs for insurance, recovery, remediation and other security measures may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

Cybersecurity breaches and information technology failures could harm our business by increasing our costs and negatively impacting our operations.

We rely extensively on information technology systems, including Internet sites, computer software, data hosting facilities and other hardware and platforms, some of which are hosted by third parties, to assist in conducting our business. Our information technology systems, as well as those of third parties we use in our operations, may be vulnerable to a variety of evolving cybersecurity risks, such as those involving unauthorized access, malicious software, data privacy breaches by employees or others with authorized access, cyber or phishing-attacks, ransomware and other security issues.

Although we have implemented information technology controls and systems that are designed to protect information and mitigate the risk of data loss and other cybersecurity risks, such measures cannot entirely eliminate cybersecurity threats, and the enhanced controls we have installed may be breached. If our information technology systems cease to function properly or our cybersecurity is breached, we could suffer disruptions to our normal operations which may include drilling, completion, production and corporate functions. A cyber attack involving our information systems and related infrastructure, or that of our business associates, could negatively impact our operations in a variety of ways, including but not limited to, the following:

- Unauthorized access to seismic data, reserves information, strategic information, or other sensitive or proprietary information could have a negative impact on our ability to compete for oil and gas resources;

- Data corruption, communication interruption, or other operational disruption during drilling activities could result in failure to reach the intended target or a drilling incident;

- Data corruption or operational disruptions of production-related infrastructure could result in a loss of production, or accidental discharge;

- A cyber attack on a vendor or service provider could result in supply chain disruptions which could delay or halt our major development projects;

- A cyber attack on third party gathering, pipeline, or rail transportation systems could delay or prevent us from transporting and marketing our production, resulting in a loss of revenues;

- A cyber attack involving commodities exchanges or financial institutions could slow or halt commodities trading, thus preventing us from marketing our production or engaging in hedging activities, resulting in a loss of revenues;

- A cyber attack which halts activities at a power generation facility or refinery using natural gas as feed stock could have a significant impact on the natural gas market, resulting in reduced demand for our production, lower natural gas prices, and reduced revenues;

- A cyber attack on a communications network or power grid could cause operational disruption resulting in loss of revenues;

- A cyber attack on our automated and surveillance systems could cause a loss in production and potential environmental hazards;

- A deliberate corruption of our financial or operating data could result in events of non-compliance which could then lead to regulatory fines or penalties; and

- A cyber attack resulting in the loss or disclosure of, or damage to, our or any of our customer's or supplier's data or confidential information could harm our business by damaging our reputation, subjecting us to potential financial or legal liability, and requiring us to incur significant costs, including costs to repair or restore our systems and data or to take other remedial steps.

All of the above could negatively impact our operational and financial results. Additionally, certain cyber incidents, such as surveillance, may remain undetected for an extended period. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

Risks Related to Our Common Stock

Our certificate of incorporation, our bylaws and Delaware law contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Our certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our certificate of incorporation, our bylaws and Delaware law could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- the organization of our board of directors as a classified board, which allows no more than approximately one-third of our directors to be elected each year;
- stockholders cannot remove directors from our board of directors except for cause and then only by the holders of not less than 66 2/3 percent of the voting power of all outstanding voting stock;
- the prohibition of stockholder action by written consent; and
- limitations on the ability of our stockholders to call special meetings and establish advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders.

Because we have no plans to pay dividends on our common stock, investors must look solely to stock appreciation for a return on their investment in us.

We do not anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain all future earnings to fund the development and growth of our business. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant. Covenants contained in our credit facility and the indentures governing our senior notes restrict the payment of dividends. Investors must rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment. Investors seeking cash dividends should not purchase our common stock.

The availability of shares for sale in the future could reduce the market price of our common stock.

In the future, we may issue securities to raise cash for acquisitions. We may also acquire interests in other companies by using a combination of cash and our common stock or just our common stock. We may also issue securities convertible into, or exchangeable for, or that represent the right to receive, our common stock. Any of these events may dilute your ownership interest in our company, reduce our earnings per share and have an adverse impact on the price of our common stock.

In addition, sales of a substantial amount of our common stock in the public market, or the perception that these sales may occur, could reduce the market price of our common stock. This could also impair our ability to raise additional capital through the sale of our securities.

The market price and trading volume of our common stock may be volatile, which could result in losses for our stockholders.

The market price of our common stock may be volatile and could be subject to wide fluctuations. In addition, the trading volume of our common stock may fluctuate and cause price variations to occur. The market price of our common stock may fluctuate or decline significantly in the future. If the market price of our common stock declines, you may be unable to sell your shares of common stock at or above your purchase price. Some of the factors that could negatively affect the price of our common stock, or result in fluctuations in the price or trading volume of our common stock, include:

- fluctuations in the price of oil or natural gas;
- variations in our quarterly operating results or failure to meet analysts' earnings expectations;

- publication of negative research reports about us or the oil and natural gas industry or adverse publicity about the oil and natural gas industry;
- adverse market reaction to any indebtedness we may incur or securities we may issue in the future or actions by our stockholders;
- sales of a large number of our common stock or the perception that such sales could occur;
- changes in market valuations of similar companies;
- the effects of government regulation, permitting and other legal requirements, including new legislation or regulation of hydraulic fracturing and the export of oil and natural gas;
- litigation and governmental investigations; and
- general economic and business conditions, either internationally or domestically.

Item 1B. Unresolved Staff Comments

There are no unresolved staff comments.

Item 2. Properties

Our Oil and Natural Gas Reserves

The estimates of our proved reserves at December 31, 2016, all of which were located in the United States, were based on evaluations prepared by the independent petroleum engineering firms of Cawley, Gillespie & Associates, Inc. ("CGA") and Netherland, Sewell & Associates, Inc. ("NSAI") (collectively, our "external engineers"). Reserves were estimated in accordance with guidelines established by the SEC and the Financial Accounting Standards Board (the "FASB").

Internal controls. Our proved reserves are estimated at the property level and compiled for reporting purposes by our corporate reservoir engineering staff, all of whom are independent of our operating teams. We maintain our internal evaluations of our reserves in a secure reserve engineering database. The corporate reservoir engineering staff interact with our internal staff of petroleum engineers, geoscience professionals and land professionals in each of our operating areas and with accounting and marketing employees to obtain the necessary data for the reserves estimation process. Reserves are reviewed and approved internally by members of our senior management and the reserves committee.

Our internal professional staff works closely with our external engineers to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. All of the reserve information maintained in our secure reserve engineering database is provided to the external engineers. In addition, other pertinent data is provided such as seismic information, geologic maps, well logs, production tests, material balance calculations, well performance data, operating procedures and relevant economic criteria. We make available all information requested, including our pertinent personnel, to the external engineers as part of their preparation of our reserves.

Qualifications of responsible technical persons

J. Steve Guthrie has been our Senior Vice President of Business Operations and Engineering since November 2013. Mr. Guthrie previously served as the Vice President of Texas from October 2010 to November 2013. Mr. Guthrie also served as Texas Asset Manager from July 2008 to October 2010 and as Corporate Engineering Manager from August 2004 to July 2008. Prior to joining the Company in 2004, Mr. Guthrie was employed by Moriah Resources as Business Development Manager, by Henry Petroleum in various engineering and operations capacities and by Exxon in several engineering and operations positions. Mr. Guthrie is a graduate of Texas Tech University with a Bachelor of Science degree in Petroleum Engineering.

Rick Morton joined the Company in 2011 as Corporate Engineering Manager. Prior to joining the Company, Mr. Morton served as Division Acquisition Coordinator for EOG Resources, Inc. Mr. Morton was also previously employed by Southwest Royalties, Inc. as Vice President and Exploitation Manager, and by Merit Energy Company in various engineering positions. Mr. Morton began his career in 1983 with Arco Oil and Gas Company as an Operations/Analytical Engineer before moving to a Production Supervisor position. He is a graduate of Texas A&M University with a Bachelor of Science degree in Petroleum Engineering.

CGA. Approximately 58 percent of the proved reserves estimates shown herein at December 31, 2016 have been independently prepared by CGA, a leader of petroleum property analysis for industry and financial institutions. CGA was founded in 1960 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-693. Within CGA, the technical person primarily responsible for preparing the estimates set forth in the CGA letter dated January 19, 2017, filed as an exhibit to this Annual Report on Form 10-K, was Mr. Zane Meekins. Mr. Meekins has been a practicing consulting petroleum engineer at CGA since 1989. Mr. Meekins is a Registered Professional Engineer in the State of Texas (License No. 71055) and has over 28 years of practical experience in petroleum engineering, with over 26 years of experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1987 with a Bachelor of Science degree in Petroleum Engineering. Mr. Meekins meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserve definitions and guidelines.

NSAI. Approximately 42 percent of the proved reserve estimates shown herein at December 31, 2016 have been independently prepared by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical person primarily responsible for preparing the estimates set forth in the NSAI letter dated January 24, 2017, filed as an exhibit to this Annual Report on Form 10-K, was Mr. Michael Begland. Mr. Begland, a Licensed Professional Engineer in the State of Texas (License No. 104898), has been practicing consulting petroleum engineering at NSAI since 1993 and has over eight years of prior industry experience. He graduated from Ohio State University in 1983 with a Bachelor of Science Degree in Chemical Engineering. Mr. Begland meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserve definitions and guidelines.

Our oil and natural gas reserves. The following table sets forth our estimated proved oil and natural gas reserves at December 31, 2016.

	Oil (MBbl)	Natural Gas (MMcf)	Total (MBoe)
Core Operating Areas:			
Northern Delaware Basin	119,899	686,654	234,341
Southern Delaware Basin	79,560	170,505	107,978
Midland Basin	121,360	420,169	191,388
New Mexico Shelf	107,208	473,607	186,143
Other	8	657	117
Total	428,035	1,751,592	719,967

The following table sets forth our estimated proved reserves by category at December 31, 2016:

	Oil (MBbl)	Natural Gas (MMcf)	Total (MBoe)	Percent of Total
Proved developed producing	253,384	1,153,115	445,570	61.9%
Proved developed non-producing	13,819	37,215	20,021	2.8%
Proved undeveloped	160,832	561,262	254,376	35.3%
Total proved	428,035	1,751,592	719,967	100.0%
Total proved developed	267,203	1,190,330	465,591	64.7%

Changes to proved reserves. The following table sets forth the changes in our proved reserve volumes by area during the year ended December 31, 2016 (in MBoe):

	Production	Extensions and Discoveries	Purchases of Minerals-in-Place	Sales of Minerals-in-Place	Revisions of Previous Estimates
Core Operating Areas:					
Northern Delaware Basin	(26,853)	44,561	29	(4,968)	(31,542)
Southern Delaware Basin	(7,277)	36,775	14,775	-	818
Midland Basin	(9,324)	36,522	43,522	(3,252)	14,064
New Mexico Shelf	(11,617)	6,913	747	(39)	(7,205)
Other	(16)	-	-	-	(127)
Total	(55,087)	124,771	59,073	(8,259)	(23,992)

Extensions and discoveries. Extensions and discoveries of approximately 124.8 MMBoe are primarily the result of our continued success from our extension and infill horizontal drilling programs in our core operating areas. Proved developed reserves increased approximately 61.1 MMBoe due to our exploratory drilling activity in 2016. Based upon this activity, approximately 63.7 MMBoe of new proved undeveloped locations were added, of which the majority are one offset location from an existing producing well.

Purchases and sales of minerals-in-place. Our purchases of minerals-in-place are composed of approximately 42.1 MMBoe from the October 2016 Reliance Acquisition, 14.8 MMBoe from the March 2016 Southern Delaware Basin acquisition and 2.2 MMBoe from various other acquisitions throughout the year. Our sales of minerals-in-place are composed of approximately 8.3 MMBoe from various divestitures throughout the year.

Revisions of previous estimates. Revisions of previous estimates are composed of (i) 57.4 MMBoe of negative revisions due to proved undeveloped reserves reclassified to unproved reserves because they are no longer expected to be developed within five years of their initial recording as required by SEC rules due to a shift in our capital program to focus more on extended length laterals as opposed to certain shorter lateral locations and (ii) 29.9 MMBoe of negative price revisions, partially offset by 63.3 MMBoe of net positive revisions related to lower lease operating expense estimates. Our proved reserves at December 31, 2016 were determined using the SEC prices of $39.25 per Bbl of oil for WTI and $2.48 per MMBtu of natural gas for Henry Hub spot, compared to corresponding prices of $46.79 per Bbl of oil and $2.59 per MMBtu of natural gas at December 31, 2015.

Proved undeveloped reserves. At December 31, 2016, we had approximately 254.4 MMBoe of proved undeveloped reserves as compared to 265.1 MMBoe at December 31, 2015.

The following table summarizes the changes in our proved undeveloped reserves during 2016 (in MBoe):

At December 31, 2015	265,143
Extensions and discoveries	63,664
Purchases of minerals-in-place	18,903
Sales of minerals-in-place	(1,598)
Revisions of previous estimates	(61,183)
Conversion to proved developed reserves	(30,553)
At December 31, 2016	254,376

Extensions and discoveries of approximately 63.7 MMBoe are primarily the result of new proved undeveloped locations that were added, of which the vast majority are one offset location from an existing producing well.

Net negative revisions of previous estimates of approximately 61.2 MMBoe are primarily attributable to (i) 57.4 MMBoe of negative revisions due to proved undeveloped reserves reclassified to unproved reserves because they are no longer expected to be developed within five years of their initial recording, (ii) 3.1 MMBoe of negative price revisions and (iii) 0.7 MMBoe of net negative miscellaneous revisions. The 57.4 MMBoe of proved undeveloped reserves in item (i) above are outside the five-year development window primarily due to results we have obtained during 2016 related to increased testing and implementation of new technologies that allows for drilling extended length laterals. The results are generally highly successful and provide sufficient data that substantiates drilling extended length laterals is generally a more efficient process than shorter lateral drilling to recover reserves. The results also generally confirm that the drilling of longer laterals is feasible on a large scale and substantially decreases the risks associated with a drilling program more focused on extended length laterals. Consequently, we shifted our capital program to focus on drilling more extended length laterals.

The following table sets forth proved undeveloped reserves converted to proved developed reserves during the respective year and the investment required to convert proved undeveloped reserves to proved developed reserves:

Years Ended December 31,	**Proved Undeveloped Reserves Converted to Proved Developed Reserves**			**Investment in Conversion of Proved Undeveloped Reserves to Proved Developed Reserves**
	Oil (MBbls)	**Natural Gas (MMcf)**	**Total (MBoe)**	**(in thousands)**
2012	19,132	60,388	29,196	$ 411,576
2013	17,050	52,237	25,756	441,998
2014	20,970	75,266	33,514	561,198
2015	19,465	65,181	30,329	464,697
2016	19,082	68,824	30,553	278,098
Total	95,699	321,896	149,348	$ 2,157,567

The following table sets forth the estimated timing and cash flows of developing our proved undeveloped reserves at December 31, 2016 (dollars in thousands):

Years Ended December 31, (a)	Future Production (MBoe)		Future Cash Inflows (b)		Future Production Costs		Future Development Costs		Future Net Cash Flows
2017	8,249	$	269,527	$	(42,103)	$	(619,297)	$	(391,873)
2018	19,393		607,503		(108,409)		(535,500)		(36,406)
2019	21,934		669,038		(131,474)		(446,207)		91,357
2020	22,453		675,761		(143,390)		(341,073)		191,298
2021	20,822		624,978		(142,942)		(154,420)		327,616
Thereafter	161,526		4,728,116		(1,524,129)		-		3,203,987
Total	254,377	$	7,574,923	$	(2,092,447)	$	(2,096,497)	$	3,385,979

(a) Beginning in 2017 and thereafter, the production and cash flows represent the drilling results from the respective year plus the incremental effects from the results of proved undeveloped drilling from previous years.

(b) Computation is based on SEC pricing of (i) $39.25 per Bbl WTI posted oil price and (ii) $2.48 per MMBtu Henry Hub spot natural gas price, adjusted for location and quality by property.

Historically, our drilling programs were substantially funded from our cash flow and borrowings from our credit facility. Based on our current expectations over the next 5 years of our cash flows and drilling programs, which includes drilling of proved undeveloped and unproven locations, we believe that we can continue to substantially fund our drilling activities from our cash flow and with borrowings from our credit facility, if needed.

Developed and Undeveloped Acreage

The following table presents our total gross and net developed and undeveloped acreage by area at December 31, 2016:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Core Operating Areas:						
Northern Delaware Basin	315,423	214,560	37,961	32,261	353,384	246,821
Southern Delaware Basin	109,263	77,668	47,985	21,982	157,248	99,650
Midland Basin	252,177	156,436	4,285	1,263	256,462	157,699
New Mexico Shelf	116,047	76,005	10,348	6,043	126,395	82,048
Other	1,338	789	-	-	1,338	789
Total	794,248	525,458	100,579	61,549	894,827	587,007

The following table sets forth the future expiration amounts of our gross and net undeveloped acreage at December 31, 2016 by area:

	2017		2018		2019		Thereafter	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Core Operating Areas:								
Northern Delaware Basin	5,128	4,198	11,045	9,271	3,567	3,490	9,195	8,177
Southern Delaware Basin (a)	19,895	10,304	21,204	8,401	5,277	2,339	152	266
Midland Basin (a)	2,941	1,030	771	102	-	12	-	-
New Mexico Shelf (a)	5,929	3,857	1,690	571	1,656	532	1,000	1,004
Total	33,893	19,389	34,710	18,345	10,500	6,373	10,347	9,447

(a) Net acres are greater than gross acres in our Midland Basin core area in 2019 and our Southern Delaware Basin and New Mexico Shelf core areas in years thereafter as certain leases contain undivided interests and have multiple net acreage expiration dates within the same tract of land. Expirations of net acres are shown in the year they occur, while the expirations of gross acres are shown in the final year of net acre expiration.

Drilling Activities

For summary tables that set forth information with respect to wells drilled and completed for the years ended December 31, 2016, 2015 and 2014, see "Item 1. Business —Drilling Activities."

Our Production, Prices and Expenses

For a summary table that sets forth information concerning our production and operating data from operations for the years ended December 31, 2016, 2015 and 2014, see "Item 1. Business —Our Production, Prices and Expenses."

Productive Wells

For a summary table that sets forth the number of productive oil and natural gas wells on our properties at December 31, 2016, 2015 and 2014, see "Item 1. Business —Productive Wells."

Title to Our Properties

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a more thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect defects affecting those properties, we are typically responsible for curing any such defects at our expense. We generally will not commence drilling operations on a property until we have cured known material title defects on such property. We have reviewed the title to substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry. Prior to completing an acquisition of producing oil and natural gas properties, we perform title reviews on the most significant properties and, depending on the materiality of properties, we may obtain a title opinion or review or update previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens to secure borrowings under our credit facility, liens for current taxes and other burdens which we believe do not materially interfere with the use or affect our carrying value of the properties.

Item 3. Legal Proceedings

We are a party to proceedings and claims incidental to our business. While many of these other matters involve inherent uncertainty, we believe that the liability, if any, ultimately incurred with respect to such other proceedings and claims will not have a material adverse effect on our consolidated financial position as a whole or on our liquidity, capital resources or future results of operations. We will continue to evaluate proceedings and claims involving us on a regular basis and will establish and adjust any reserves as appropriate to reflect our assessment of the then current status of the matters.

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

Market Information

Our common stock trades on the NYSE under the symbol "CXO." The following table shows, for the periods indicated, the high and low sales prices for our common stock, as reported on the NYSE.

	Price Per Share	
	High	Low
2015:		
First Quarter	$ 122.14	$ 91.26
Second Quarter	$ 134.13	$ 110.44
Third Quarter	$ 115.13	$ 92.41
Fourth Quarter	$ 120.41	$ 85.87
2016:		
First Quarter	$ 107.00	$ 69.94
Second Quarter	$ 130.03	$ 95.87
Third Quarter	$ 137.83	$ 114.33
Fourth Quarter	$ 147.55	$ 123.88

On February 17, 2017, the last sales price of our common stock as reported on the NYSE was $140.06 per share.

As of February 17, 2017, there were 1,109 holders of record of our common stock.

Dividend Policy

We have not paid, and do not intend to pay in the foreseeable future, cash dividends on our common stock. Covenants contained in our credit facility and the indentures governing our senior notes limit the payment of dividends on our common stock. We currently intend to retain all future earnings to fund the development and growth of our business. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant. See Note 9 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Repurchases of Equity Securities

Period	Total number of shares withheld (a)	Average price per share	Total number of shares purchased as part of publicly announced plans	Maximum number of shares that may yet be purchased under the plan
October 1, 2016 - October 31, 2016	137	$ 138.74	-	
November 1, 2016 - November 30, 2016	103	$ 130.65	-	
December 1, 2016 - December 31, 2016	384	$ 137.97	-	

(a) Represents shares that were withheld by us to satisfy tax withholding obligations of certain of our officers and key employees that arose upon the lapse of restrictions on restricted stock.

Item 6. Selected Financial Data

This section presents our selected historical consolidated financial data. The selected historical consolidated financial data presented below is not intended to replace our historical consolidated financial statements. You should read the following data along with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements and related notes, each of which is included in this report.

Selected Historical Financial Information

Our results of operations for the periods presented below may not be comparable either from period to period or going forward for the following reasons:

- in May 2014, we issued in a secondary public offering 7.5 million shares of our common stock at $129.00 per share, and we received net proceeds of approximately $932.0 million;

- in March 2015, we issued 6.9 million shares of our common stock in a public offering at $107.49 per share, and we received net proceeds of approximately $741.5 million;

- in October 2015, we issued approximately 8.9 million shares of our common stock in a public offering at $92.50 per share, and we received net proceeds of approximately $794.2 million;

- in December 2015, we completed an acreage exchange with Clayton Williams Energy, Inc. that consolidated acres into a concentrated, operated position in the Southern Delaware Basin. We recognized a loss on disposition of assets of approximately $50.0 million related to the acreage exchange;

- in February 2016, we sold certain assets in the Northern Delaware Basin for proceeds of approximately $292.0 million and recognized a pre-tax gain of approximately $110.1 million;

- in March 2016, we completed an acquisition of 80 percent of a third-party seller's interest in certain oil and natural gas properties and related assets in the Southern Delaware Basin. As consideration for the acquisition, we issued to the seller approximately 2.2 million shares of common stock with an approximate value of $230.8 million, $146.2 million in cash and $40.0 million to carry a portion of the seller's future development costs in these properties;

- in August 2016, we issued approximately 10.4 million shares of our common stock in a public offering at $130.90 per share and received net proceeds of approximately $1.3 billion. We used a portion of the net proceeds to finance part of the cash portion of the purchase price for the Reliance Acquisition and to fund part of the early redemption of our 7.0% unsecured senior notes due 2021 (the "7.0% Notes"), and the remainder for general corporate purposes;

- in September 2016, we redeemed the $600 million outstanding principal amount of our 7.0% Notes at a price equal to 103.5 percent of par. The redemption price included the make-whole premium for the early redemption, as determined in accordance with the indenture governing the 7.0% Notes. We also paid accrued and unpaid interest on the 7.0% Notes through September 19, 2016, the redemption date. We recorded a loss on extinguishment of debt related to the redemption of the 7.0% Notes of approximately $27.7 million. This amount includes $21.0 million associated with the make-whole premium paid for the early redemption of the notes and approximately $6.7 million of unamortized deferred loan costs;

- in October 2016, we completed the Reliance Acquisition. As consideration for the acquisition, we paid approximately $1.2 billion in cash and issued to the seller approximately 3.9 million shares of common stock with an approximate value of $0.5 billion; and

- in December 2016, we issued $600 million in aggregate principal amount of 4.375% senior notes due 2025 (the "4.375% Notes") at par, for which we received net proceeds of approximately $592.1 million. We used the net proceeds from the offering to fund the satisfaction and discharge of our obligations under the indenture of the $600 million outstanding principal amount of our 6.5% unsecured senior notes due 2022 (the "6.5% Notes") at a price equal to 103.25 percent of par.

Our financial data below is derived from (i) our audited consolidated financial statements included in this report and (ii) other audited consolidated financial statements of ours not included in this report.

	Years Ended December 31,				
(in thousands, except per share amounts)	**2016 (a)**	**2015**	**2014**	**2013**	**2012 (b)**
Statement of operations data:					
Total operating revenues	$ 1,634,988	$ 1,803,573	$ 2,660,147	$ 2,319,919	$ 1,819,814
Total operating costs and expenses	(3,704,432)	(1,476,359)	(1,579,710)	(1,703,750)	(969,623)
Income (loss) from operations	$ (2,069,444)	$ 327,214	$ 1,080,437	$ 616,169	$ 850,191
Income (loss) from continuing operations, net of tax	$ (1,462,446)	$ 65,900	$ 538,175	$ 238,922	$ 408,230
Income from discontinued operations, net of tax	-	-	-	12,081	23,459
Net income (loss) attributable to common shareholders	$ (1,462,446)	$ 65,900	$ 538,175	$ 251,003	$ 431,689
Basic earnings per share:					
Income (loss) from continuing operations	$ (10.85)	$ 0.54	$ 4.89	$ 2.28	$ 3.96
Income from discontinued operations, net of tax	-	-	-	0.11	0.22
Net income (loss) attributable to common shareholders	$ (10.85)	$ 0.54	$ 4.89	$ 2.39	$ 4.18
Diluted earnings per share:					
Income (loss) from continuing operations	$ (10.85)	$ 0.54	$ 4.88	$ 2.28	$ 3.93
Income from discontinued operations, net of tax	-	-	-	0.11	0.22
Net income (loss) attributable to common shareholders	$ (10.85)	$ 0.54	$ 4.88	$ 2.39	$ 4.15
Other financial data:					
Net cash provided by operations	$ 1,384,448	$ 1,530,421	$ 1,745,770	$ 1,329,679	$ 1,261,014
Net cash used in investing activities	$ 2,224,656	$ 2,602,641	$ 2,617,979	$ 1,864,453	$ 2,263,980
Net cash provided by financing activities	$ 664,919	$ 1,300,749	$ 872,209	$ 531,915	$ 1,005,504
EBITDAX (c)	$ 1,633,158	$ 1,712,910	$ 2,033,225	$ 1,685,592	$ 1,475,628

	December 31,				
(in thousands)	**2016 (a)**	**2015**	**2014**	**2013**	**2012 (b)**
Balance sheet data:					
Cash and cash equivalents	$ 53,261	$ 228,550	$ 21	$ 21	$ 2,880
Property and equipment, net	11,302,433	10,976,947	10,206,014	8,946,048	7,993,424
Total assets	12,119,326	12,641,876	11,751,780	9,507,931	8,540,234
Long-term debt, including current maturities	2,740,580	3,332,188	3,469,137	3,577,257	3,051,900
Stockholders' equity	7,622,693	6,942,551	5,280,788	3,757,949	3,466,196

(a) The Reliance Acquisition closed in October 2016. See Note 4 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data." Additionally, $1.5 billion of impairment expense is included in income (loss) from operations for the year ended December 31, 2016.

(b) The acquisition of producing and non-producing assets from Three Rivers Operating Company LLC and certain affiliated entities closed in July 2012.

(c) EBITDAX is defined as net income (loss), plus (1) exploration and abandonments expense, (2) depreciation, depletion and amortization expense, (3) accretion expense, (4) impairments of long-lived assets, (5) non-cash stock-based compensation expense, (6) (gain) loss on derivatives, (7) net cash receipts from (payments on) derivatives, (8) (gain) loss on disposition of assets, net, (9) interest expense, (10) loss on extinguishment of debt, (11) federal and state income tax expense (benefit) from continuing operations and (12) similar items listed above that are presented in discontinued operations. See "Item 1. Business —Non-GAAP Financial Measures and Reconciliations."

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

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. This section should be read in conjunction with our historical consolidated financial statements and notes, as well as the selected historical consolidated financial data included elsewhere in this report.

Certain statements in our discussion below are forward-looking statements. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause actual results to differ materially from those implied or expressed by the forward-looking statements. Please see "Cautionary Statement Regarding Forward-Looking Statements."

Overview

We are an independent oil and natural gas company engaged in the acquisition, development, exploration and production of oil and natural gas properties. Our core operations are primarily focused in the Permian Basin of southeast New Mexico and west Texas. Concho's legacy in the Permian Basin provides us a deep understanding of operating and geological trends. We are actively applying new technologies, such as extended length lateral drilling and enhanced completion techniques, throughout our four core operating areas: the Northern Delaware Basin, the Southern Delaware Basin, the Midland Basin and the New Mexico Shelf. Oil comprised 59.5 percent of our 720.0 MMBoe of estimated proved reserves at December 31, 2016 and 61.4 percent of our 55.1 MMBoe of production for 2016. We seek to operate the wells in which we own an interest, and we operated wells that accounted for 91.9 percent of our proved developed producing reserves and 79.0 percent of our 7,858 gross wells at December 31, 2016. By controlling operations, we are able to more effectively manage the cost and timing of exploration and development of our properties, including the drilling and stimulation methods used.

Financial and Operating Performance

Our financial and operating performance for 2016 included the following highlights:

- Net loss was $1.5 billion ($(10.85) per diluted share) as compared to net income of $65.9 million ($0.54 per diluted share) in 2015. The decrease was primarily due to:
  - $1.5 billion in impairments of long-lived assets during 2016, primarily attributable to properties in our New Mexico Shelf area, as compared to $60.5 million in non-cash impairment charges in 2015;
  - $1.1 billion change in (gain) loss on derivatives due to a $368.7 million loss on derivatives during 2016, as compared to a $699.8 million gain on derivatives during 2015;
  - $168.6 million decrease in oil and natural gas revenues as a result of a 14 percent decrease in commodity price realizations per Boe (excluding the effects of derivative activities), partially offset by a 5 percent increase in production;
  - $56.4 million loss on extinguishment of debt related to the early redemption of our 7.0% unsecured senior notes due 2021 (the “7.0% Notes”) in September 2016 and early extinguishment of our 6.5% Notes in December 2016; and
  - $18.6 million increase in exploration and abandonment expense primarily due to leasehold abandonments in 2016 as compared to 2015;

  partially offset by:
  - $907.5 million change in our income tax (expense) benefit due to the loss before income taxes during 2016, as compared to income before income taxes during 2015;
  - $171.4 million change in (gain) loss on disposition of assets, net primarily due to our February 2016 asset divestiture;
  - $90.1 million decrease in oil and natural gas production expense, primarily due to implementation of operational cost efficiencies, an overall decrease in the cost of goods and services and lower production taxes as a result of reduced revenues; and
  - $56.0 million decrease in depreciation, depletion and amortization expense, primarily due to slightly lower depletion rate per Boe period over period.
- Average daily sales volumes increased by 5 percent from 143,256 Boe per day during 2015 to 150,511 Boe per day during 2016. The increase is primarily attributable to our successful drilling and completion efforts during 2015 and 2016 and the Reliance Acquisition, which was completed in October 2016.
- Net cash provided by operating activities decreased by approximately $146.0 million to $1,384.4 million for 2016, as compared to $1,530.4 million in 2015, primarily due to a decrease in oil and natural gas revenues and negative variances in working capital changes, partially offset by decreased production expenses, changes related to cash income taxes and decreased cash interest expense.
- Cash decreased by approximately $175.3 million during 2016 primarily as a result of cash consideration paid for the Reliance Acquisition, cash consideration paid related to our asset acquisition that closed in March 2016, cash paid to redeem the 7.0% Notes, cash paid to extinguish the 6.5% Notes and capital expenditures for properties, partially offset by the proceeds from our August 2016 equity offering, proceeds from the issuance of our 4.375% Notes, our divestiture that closed in February 2016 and operating cash flows.

Commodity Prices

Our results of operations are heavily influenced by commodity prices. Commodity prices may fluctuate widely in response to (i) relatively minor changes in the supply of and demand for oil, natural gas and natural gas liquids, (ii) market uncertainty and (iii) a variety of additional factors that are beyond our control. Factors that may impact future commodity prices, including the price of oil, natural gas and natural gas liquids, include, but are not limited to:

- continuing economic uncertainty worldwide;
- political and economic developments in oil and natural gas producing regions, including Africa, South America and the Middle East;
- the extent to which members of the Organization of Petroleum Exporting Countries and other oil exporting nations are able to influence global oil supply levels;
- technological advances affecting energy consumption and energy supply;
- domestic and foreign governmental regulations, including limits on the United States' ability to export crude oil, and taxation;
- the level of global inventories;
- the proximity, capacity, cost and availability of pipelines and other transportation facilities, as well as the availability of commodity processing and gathering and refining capacity;
- risks related to the concentration of our operations in the Permian Basin of Southeast New Mexico and West Texas and the level of commodity inventory in the Permian Basin;
- the quality of the oil we produce;
- the overall global demand for oil, natural gas and natural gas liquids;
- the domestic and foreign supply of oil, natural gas and natural gas liquids;
- political and economic events that directly or indirectly impact the relative strength or weakness of the United States dollar, on which oil prices are benchmarked globally, against foreign currencies;
- the effect of energy conservation efforts;
- the price and availability of alternative fuels; and
- overall North American oil, natural gas and natural gas liquids supply and demand fundamentals, including:
  - the United States economy,
  - weather conditions, and
  - liquefied natural gas deliveries to and exports from the United States.

Although we cannot predict the occurrence of events that may affect future commodity prices or the degree to which these prices will be affected, the prices for any commodity that we produce will generally approximate current market prices in the geographic region of the production. From time to time, we expect that we may economically hedge a portion of our commodity price risk to mitigate the impact of price volatility on our business. See Notes 8 and 17 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding our commodity derivative positions at December 31, 2016 and additional derivative contracts entered into subsequent to December 31, 2016, respectively.

Oil and natural gas prices have been subject to significant fluctuations during the past several years. The average oil and natural gas prices were lower during 2016 compared to 2015. The following table sets forth the average NYMEX oil and natural gas prices for the years ended December 31, 2016, 2015 and 2014, as well as the high and low NYMEX prices for the same periods:

	Years Ended December 31,		
	2016	**2015**	**2014**
Average NYMEX prices:			
Oil (Bbl)	$ 43.42	$ 48.84	$ 92.94
Natural gas (MMBtu)	$ 2.56	$ 2.63	$ 4.27
High and Low NYMEX prices:			
Oil (Bbl):			
High	$ 54.06	$ 61.43	$ 107.26
Low	$ 26.21	$ 34.73	$ 53.27
Natural gas (MMBtu):			
High	$ 3.93	$ 3.23	$ 6.15
Low	$ 1.64	$ 1.76	$ 2.89

Further, the NYMEX oil price and NYMEX natural gas price reached highs and lows of $53.99 and $50.82 per Bbl and $3.72 and $2.83 per MMBtu, respectively, during the period from January 1, 2017 to February 17, 2017. At February 17, 2017, the NYMEX oil price and NYMEX natural gas price were $53.40 per Bbl and $2.83 per MMBtu, respectively.

Over the past three years, approximately half of our total natural gas revenues have been derived from the value of the natural gas liquids contained in our natural gas, with the remaining portion coming from the value of the dry natural gas residue. The average Mont Belvieu price for a blended barrel of natural gas liquids was $18.08 per Bbl and $17.80 per Bbl during the years ended December 31, 2016 and 2015, respectively.

Recent Events

2017 capital budget. In February 2017, we announced our updated 2017 capital budget, excluding acquisitions, of approximately $1.8 billion with expected capital spending to range between $1.6 billion and $1.8 billion. Approximately 90 percent of capital will be directed to drilling and completion activity. Our 2017 capital program is expected to continue focusing on extended length lateral drilling. Our 2017 capital budget, based on our current expectations of commodity prices and costs, is expected to be within our cash flows. Our budget could change depending on numerous factors, including commodity prices, leverage metrics and industry conditions.

ACC divestiture. In January 2017, we and our joint venture partner entered into separate agreements to sell 100 percent of our respective ownership interests in ACC for a combined total of $1.215 billion. After adjustments for debt and working capital, we received net cash proceeds from the sale of approximately $802.8 million. Our net investment in ACC was approximately $128.7 million at December 31, 2016. The transaction closed in February 2017.

Northern Delaware Basin acquisition. In November 2016, we announced an acquisition of approximately 16,400 net acres in the Northern Delaware Basin for approximately $430.0 million. As consideration for the acquisition, we agreed to issue to the seller approximately 2.2 million shares of our common stock and $150.0 million in cash. In January 2017, we closed on a portion of the acquisition and expect to close on the remainder during the first half of 2017.

Senior notes. In December 2016, we issued $600 million in aggregate principal amount of 4.375% senior notes due 2025 at par, for which we received net proceeds of approximately $592.1 million. We used the net proceeds from the offering to fund the satisfaction and discharge of our obligations under the indenture of the $600 million outstanding principal amount of our 6.5% Notes at a price equal to 103.25 percent of par. The early extinguishment price included the make-whole premium as determined in accordance with the indenture governing the 6.5% Notes. In December 2016, we also paid interest of approximately $19.6 million on the 6.5% Notes through January 16, 2017.

We recorded a loss on extinguishment of debt related to the 6.5% Notes of approximately $28.7 million for the year ended December 31, 2016. This amount includes $19.5 million associated with the make-whole premium paid for the early extinguishment of the notes, approximately $7.3 million of unamortized deferred loan costs and approximately $1.9 million of additional interest on the 6.5% Notes through January 16, 2017, which was paid in December 2016.

Reliance Acquisition. In October 2016, we completed the Reliance Acquisition. As consideration for the acquisition, we paid approximately $1.2 billion in cash and issued to the seller approximately 3.9 million shares of common stock with an approximate value of $0.5 billion.

Derivative Financial Instruments

Derivative financial instrument exposure. At December 31, 2016, the fair value of our financial derivatives was a net liability of $174.4 million. All of our counterparties to these financial derivatives are parties to our credit facility and have their outstanding debt commitments and derivative exposures collateralized pursuant to our credit facility. At December 31, 2016, under the terms of our financial derivative instruments and their collateralization under our credit facility, we do not have exposure to potential "margin calls" on our financial derivative instruments. We currently have no reason to believe that our counterparties to these commodity derivative contracts are not financially viable. Under the terms of our credit facility, certain events could occur that would cause the obligations under our credit facility to no longer be secured by our oil and natural gas properties. In this circumstance, we have certain agreements in place with our derivative counterparties that would regulate collateral related to derivative transactions. See Note 12 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information. Our credit facility does not allow us to offset amounts we may owe a lender against amounts we may be owed related to our financial instruments with such party.

New commodity derivative contracts. After December 31, 2016, we entered into the following additional oil price swaps to hedge additional amounts of our estimated future production:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Swaps: (a)					
2017:					
Volume (Bbl)	403,000	1,360,000	1,044,000	868,000	3,675,000
Price per Bbl	$ 55.32	$ 55.20	$ 55.36	$ 55.56	$ 55.34
2018:					
Volume (Bbl)	736,000	652,000	580,000	523,000	2,491,000
Price per Bbl	$ 55.47	$ 55.48	$ 55.54	$ 55.61	$ 55.52
2019:					
Volume (Bbl)	2,355,000	2,253,000	2,163,000	2,083,000	8,854,000
Price per Bbl	$ 55.15	$ 55.11	$ 55.14	$ 55.16	$ 55.14

(a) The index prices for the oil price swaps are based on the NYMEX – WTI monthly average futures price.

Results of Operations

The following table sets forth summary information concerning our production and operating data for the years ended December 31, 2016, 2015 and 2014. The actual historical data in this table excludes results from the Reliance Acquisition for periods prior to October 2016. Because of normal production declines, increased or decreased drilling activities, fluctuations in commodity prices and the effects of acquisitions or divestitures, the historical information presented below should not be interpreted as being indicative of future results.

	Years Ended December 31,		
	2016	2015	2014
Production and operating data:			
Net production volumes:			
Oil (MBbl)	33,840	34,457	26,319
Natural gas (MMcf)	127,481	106,987	87,336
Total (MBoe)	55,087	52,288	40,875
Average daily production volumes:			
Oil (Bbl)	92,459	94,403	72,107
Natural gas (Mcf)	348,309	293,115	239,277
Total (Boe)	150,511	143,256	111,987
Average prices per unit:			
Oil, without derivatives (Bbl)	$ 39.90	$ 44.69	$ 83.17
Oil, with derivatives (Bbl) (a)	$ 57.90	$ 62.03	$ 86.07
Natural gas, without derivatives (Mcf)	$ 2.23	$ 2.46	$ 5.39
Natural gas, with derivatives (Mcf) (a)	$ 2.36	$ 2.80	$ 5.34
Total, without derivatives (Boe)	$ 29.68	$ 34.49	$ 65.08
Total, with derivatives (Boe) (a)	$ 41.03	$ 46.60	$ 66.84
Operating costs and expenses per Boe:			
Lease operating expenses and workover costs	$ 5.81	$ 7.46	$ 8.05
Oil and natural gas taxes	$ 2.38	$ 2.90	$ 5.12
Depreciation, depletion and amortization	$ 21.19	$ 23.40	$ 23.97
General and administrative	$ 4.09	$ 4.42	$ 4.99

(a) Includes the effect of net cash receipts from (payments on) derivatives:

	Years Ended December 31,		
(in thousands)	2016	2015	2014
Net cash receipts from (payments on) derivatives:			
Oil derivatives	$ 608,847	$ 597,297	$ 76,335
Natural gas derivatives	16,403	35,619	(4,352)
Total	$ 625,250	$ 632,916	$ 71,983

The presentation of average prices with derivatives is a result of including the net cash receipts from (payments on) commodity derivatives that are presented in our statements of cash flows. This presentation of average prices with derivatives is a means by which to reflect the actual cash performance of our commodity derivatives for the respective periods and presents oil and natural gas prices with derivatives in a manner consistent with the presentation generally used by the investment community.

The following table presents selected production data for the fields which represent greater than 15 percent of our total proved reserves at December 31, 2016, 2015 and 2014:

	Year Ended December 31,		
	2016	2015	2014
Production:			
South Basin Wolfcamp Bone Spring:			
Oil (MBbl)	10,461	9,742	6,024
Natural gas (MMcf)	55,793	36,895	25,447
Total (MBoe)	19,760	15,891	10,265
Yeso:			
Oil (MBbl)	7,047	6,986	6,929
Natural gas (MMcf)	27,322	26,833	27,409
Total (MBoe)	11,601	11,458	11,497
Wolfberry West:			
Oil (MBbl)	5,703	(a)	(a)
Natural gas (MMcf)	20,942	(a)	(a)
Total (MBoe)	9,193	(a)	(a)

(a) Represented less than 15% of the Company's total proved reserves for the year indicated.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

Oil and natural gas revenues. Revenue from oil and natural gas operations was $1,635.0 million for the year ended December 31, 2016, a decrease of $168.6 million (9 percent) from $1,803.6 million for 2015. This decrease was primarily due to the decrease in realized oil and natural gas prices partially offset by an increase in natural gas production. Specific factors affecting oil and natural gas revenues include the following:

- total oil production was 33,840 MBbl for the year ended December 31, 2016, a decrease of 617 MBbl (1.8 percent) from 34,457 MBbl for 2015;

- average realized oil price (excluding the effects of derivative activities) was $39.90 per Bbl during the year ended December 31, 2016, a decrease of 10.7 percent from $44.69 per Bbl during 2015. For the year ended December 31, 2016, our crude oil price differential relative to NYMEX was $(3.52) per Bbl, or a realization of approximately 91.9 percent, as compared to a crude oil price differential relative to NYMEX of $(4.15) per Bbl, or a realization of approximately 91.5 percent, for 2015. We incur fixed deductions from the posted Midland oil price based on the location of our oil within the Permian Basin. Additionally, the basis differential between the location of Midland, Texas and Cushing, Oklahoma (NYMEX pricing location) for our oil directly impacts our realized oil price. For the years ended December 31, 2016 and 2015, the average market basis differential between WTI-Midland and WTI-Cushing was a price reduction of $0.15 per Bbl and $0.41 per Bbl, respectively;

- total natural gas production was 127,481 MMcf for the year ended December 31, 2016, an increase of 20,494 MMcf (19.2 percent) from 106,987 MMcf for 2015; and

- average realized natural gas price (excluding the effects of derivative activities) was $2.23 per Mcf during the year ended December 31, 2016, a decrease of 9.3 percent from $2.46 per Mcf during 2015. For the years ended December 31, 2016 and 2015, we realized approximately 87.1 percent and 93.5 percent, respectively, of the average NYMEX natural gas prices for the respective periods. Factors contributing to the decrease in our realized gas price (excluding the effects of derivatives) as a percentage of NYMEX during the year ended December 31, 2016 as compared to 2015 were (i) a decrease in the posted regional natural gas prices on which we are paid while the NYMEX natural gas price decreased at a lesser rate and (ii) increased deductions and fees from the regional natural gas price, comparatively. Over the past three years, approximately half of our total natural gas revenues have been derived from the value of the natural gas liquids contained in our natural gas, with the remaining portion coming from the value of the dry natural gas residue. The average Mont Belvieu price for a blended barrel of natural gas liquids was $18.08 per Bbl and $17.80 per Bbl during the years ended December 31, 2016 and 2015, respectively.

Production expenses. The following table provides the components of our total oil and natural gas production costs for the years ended December 31, 2016 and 2015:

	Years Ended December 31,			
	2016		2015	
(in thousands, except per unit amounts)	Amount	Per Boe	Amount	Per Boe
Lease operating expenses	$ 300,797	$ 5.46	$ 362,114	$ 6.93
Workover costs	19,057	0.35	27,590	0.53
Taxes:				
Ad valorem	14,017	0.25	22,921	0.44
Production	117,433	2.13	128,734	2.46
Total oil and natural gas production expenses	$ 451,304	$ 8.19	$ 541,359	$ 10.36

Among the cost components of production expenses, we have some control over lease operating expenses and workover costs on properties we operate, but production and ad valorem taxes are related to commodity prices.

Lease operating expenses were $300.8 million ($5.46 per Boe) for the year ended December 31, 2016, which was a decrease of $61.3 million (17 percent) from $362.1 million ($6.93 per Boe) for the year ended December 31, 2015. The decrease in lease operating expenses was primarily due to (i) implementation of operational cost efficiencies and (ii) an overall decrease in the cost of goods and services. The decrease in lease operating expenses per Boe was primarily due to the reduction in lease operating expenses noted above coupled with a slight increase in production period over period.

Workover expenses were approximately $19.1 million and $27.6 million for the years ended December 31, 2016 and 2015, respectively. The decrease was primarily related to less overall activity during 2016 as compared to 2015.

Production taxes per unit of production were $2.13 per Boe during the year ended December 31, 2016, a decrease of 13 percent from $2.46 per Boe during 2015. The decrease was directly related to the decrease in oil and natural gas prices. Over the same period, our average realized prices per Boe (excluding the effects of derivatives) decreased 14 percent.

Exploration and abandonments expense. The following table provides a breakdown of our exploration and abandonments expense for the years ended December 31, 2016 and 2015:

	Years Ended December 31,	
(in thousands)	2016	2015
Geological and geophysical	$ 8,441	$ 9,694
Exploratory dry hole costs	6,791	9,205
Leasehold abandonments	59,830	34,532
Other	2,392	5,416
Total exploration and abandonments	$ 77,454	$ 58,847

Our geological and geophysical expense for the periods presented above primarily consists of the costs of acquiring and processing geophysical data and core analysis.

Our exploratory dry hole costs during the year ended December 31, 2016 were primarily related to an uneconomic well in our Northern Delaware Basin core area that was attempting to establish commercial production through testing of multiple zones. Our exploratory dry hole costs during the year ended December 31, 2015 were primarily related to (i) an uneconomic well in our Southern Delaware Basin core area that was attempting to establish production in an unconventional zone for the area and (ii) expensing an unsuccessful well, which we did not operate, that was located in our New Mexico Shelf core area.

During the year ended December 31, 2016, we recognized leasehold abandonment expense of approximately $59.8 million primarily related to (i) drilling locations in our Northern Delaware Basin and New Mexico Shelf core areas which, based on multiple factors, are no longer likely to be drilled, (ii) acreage in our Northern Delaware Basin and New Mexico Shelf core areas where we have no future development plans and (iii) expiring acreage primarily located in our Northern Delaware Basin and Southern Delaware Basin core areas.

During the year ended December 31, 2015, we recognized leasehold abandonment expense of approximately $34.5 million primarily related to expired and abandoned acreage in our Northern Delaware Basin core area where we currently have no intent to drill.

Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the years ended December 31, 2016 and 2015:

	Years Ended December 31,			
	2016		2015	
(in thousands, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Depletion of proved oil and natural gas properties	$ 1,145,165	$ 20.79	$ 1,203,469	$ 23.02
Depreciation of other property and equipment	20,582	0.37	18,323	0.35
Amortization of intangible assets - operating rights	1,461	0.03	1,461	0.03
Total depletion, depreciation and amortization	$ 1,167,208	$ 21.19	$ 1,223,253	$ 23.40
Oil price used to estimate proved oil reserves at period end	$ 39.25		$ 46.79	
Natural gas price used to estimate proved natural gas reserves at period end	$ 2.48		$ 2.59	

Depletion of proved oil and natural gas properties was $1,145.2 million ($20.79 per Boe) for the year ended December 31, 2016, a decrease of $58.3 million (5 percent) from $1,203.5 million ($23.02 per Boe) for 2015. The decrease in depletion expense was primarily due to a lower depletion rate per Boe period over period partially offset by an increase in production. The decrease in depletion expense per Boe period over period was primarily due to (i) a non-cash impairment charge of approximately $1.5 billion recorded in the first quarter of 2016 and (ii) an overall increase in proved reserves period over period primarily caused by our successful exploratory drilling program, the Reliance Acquisition and reductions in future estimated lease operating expenses, partially offset by decreased proved reserves caused by (i) reclassification of proved undeveloped reserves to unproved reserves because they are no longer expected to be developed within five years of their initial recording and (ii) lower commodity prices.

The increase in depreciation expense was primarily associated with additional other property and equipment related to buildings and other items.

Impairments of long-lived assets. We periodically review our long-lived assets to be held and used, including proved oil and natural gas properties and their integrated assets, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable, for instance when there are declines in commodity prices or well performance. We review our oil and natural gas properties by depletion base. An impairment loss is indicated if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. If the estimated undiscounted future net cash flows are less than the carrying amount of our assets, we recognize an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset.

We calculate the expected undiscounted future net cash flows of our long-lived assets and their integrated assets using management's assumptions and expectations of (i) commodity prices, which are based on the NYMEX strip, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) production volumes, (vi) estimated proved reserves and risk-adjusted probable and possible reserves, and (vii) prevailing market rates of income and expenses from integrated assets. At December 31, 2016, our estimates of commodity prices for purposes of determining undiscounted future cash flows, which are based on the NYMEX strip, ranged from a 2017 price of $56.19 per barrel of oil to a 2024 price of $57.41 per barrel of oil. Similarly, natural gas prices ranged from a 2017 price of $3.61 per Mcf of natural gas decreasing to a 2020 price of $2.88 per Mcf of natural gas partially recovering to a 2024 price of $3.38 per Mcf of natural gas. Commodity prices for this purpose were held flat after 2024.

We calculate the estimated fair values of our long-lived assets and their integrated assets using a discounted future cash flow model. Fair value assumptions associated with the calculation of discounted future net cash flows include (i) market estimates of commodity prices, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) production volumes, (vi) estimated proved reserves and risk-adjusted probable and possible reserves, (vii) prevailing market rates of income and expenses from integrated assets and (viii) discount rate. The expected future net cash flows were discounted using an annual rate of 10 percent to determine fair value.

During the three months ended March 31, 2016, NYMEX strip prices declined as compared to December 31, 2015, and as a result the carrying amount of our Yeso field in our New Mexico Shelf core area exceeded the expected undiscounted future net cash flows resulting in a non-cash charge against earnings of approximately $1.5 billion. The Yeso field, as compared to our other fields not previously impaired, had significant proved reserves upon acquisition, which required a higher valuation than a field more exploratory in nature that has a higher risk factor adjustment in the fair value estimate. Our estimates of commodity prices for purposes of determining the estimated fair value at March 31, 2016 ranged from a 2016 price of $41.26 per barrel of oil and $2.26 per Mcf of natural gas to a 2022 price of $66.33 per barrel of oil and $3.56 per Mcf of natural gas. Commodity prices for this purpose were held flat after 2022.

We recognized a non-cash charge against earnings of approximately $60.5 million for the year ended December 31, 2015 as a result of the carrying amount of certain of our long-lived assets and their integrated assets being less than their expected undiscounted future net cash flows, which was primarily attributable to properties in our eastern Midland Basin area.

It is reasonably possible that the estimate of undiscounted future net cash flows of our long-lived assets may change in the future resulting in the need to impair carrying values. The primary factors that may affect estimates of future net cash flows are (i) commodity futures prices, (ii) increases or decreases in production and capital costs, (iii) future reserve volume adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves, (iv) results of future drilling activities and (v) prevailing market rates of income and expenses from integrated assets. If the oil and natural gas prices used in this analysis would have been approximately 10 percent lower as of December 31, 2016 with no other changes in capital costs, operating costs, price differentials, or reserve volumes, no impairment would be indicated.

General and administrative expenses. The following table provides components of our general and administrative expenses for the years ended December 31, 2016 and 2015:

	Years Ended December 31,			
	2016		2015	
(in thousands, except per unit amounts)	Amount	Per Boe	Amount	Per Boe
General and administrative expenses	$ 183,500	$ 3.33	$ 186,880	$ 3.58
Less: Operating fee reimbursements	(16,862)	(0.31)	(19,219)	(0.37)
Non-cash stock-based compensation	58,927	1.07	63,073	1.21
Total general and administrative expenses	$ 225,565	$ 4.09	$ 230,734	$ 4.42

General and administrative expenses were approximately $225.6 million ($4.09 per Boe) for the year ended December 31, 2016, a decrease of $5.1 million (2 percent) from $230.7 million ($4.42 per Boe) for 2015. The decrease in non-cash stock-based compensation was primarily due to an increase in forfeiture estimates. The decrease in total general and administrative expenses per Boe was primarily due to the reduction in non-cash stock-based compensation costs noted above coupled with a slight increase in production period over period.

We receive fees for the operation of jointly-owned oil and natural gas properties during the drilling and production phases and record such reimbursements as reductions of general and administrative expenses in the consolidated statements of operations. We earned reimbursements of $16.9 million and $19.2 million during the years ended December 31, 2016 and 2015, respectively. The decrease in reimbursements was primarily due to decreased drilling and completion activity during 2016 and a higher average working interest in our wells drilled in 2016 as compared to 2015, partially offset by increased reimbursements attributable to more wells operated in 2016 as compared to 2015.

Gain (loss) on derivatives. The following table sets forth the gain (loss) on derivatives for the years ended December 31, 2016 and 2015:

	Years Ended December 31,	
(in thousands)	**2016**	**2015**
Gain (loss) on derivatives:		
Oil derivatives	$ (337,175)	$ 675,303
Natural gas derivatives	(31,509)	24,449
Total	$ (368,684)	$ 699,752

The following table represents our net cash receipts from derivatives for the years ended December 31, 2016 and 2015:

	Years Ended December 31,	
(in thousands)	**2016**	**2015**
Net cash receipts from derivatives:		
Oil derivatives	$ 608,847	$ 597,297
Natural gas derivatives	16,403	35,619
Total	$ 625,250	$ 632,916

Our earnings are affected by the changes in value of our derivatives portfolio between periods and the related cash settlements of those derivatives, which could be significant. To the extent the future commodity price outlook declines between measurement periods, we will have mark-to-market gains, while to the extent future commodity price outlook increases between measurement periods, we will have mark-to-market losses. See Note 7 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding significant judgments made in classifying financial instruments in the fair value hierarchy.

Gain (loss) on disposition of assets, net. During the years ended December 31, 2016 and 2015, we recognized a gain on disposition of assets of approximately $117.6 million and a loss on disposition of assets of approximately $53.8 million, respectively. In February 2016, we sold certain assets in our Northern Delaware Basin core area for proceeds of approximately $292.0 million and recognized a pre-tax gain of approximately $110.1 million. In December 2015, we completed an acreage exchange with Clayton Williams Energy, Inc. that consolidated acres into a concentrated, operated position in our Southern Delaware Basin core area. We recognized a loss on disposition of assets of approximately $50.0 million related to the acreage exchange.

Interest expense. The following table sets forth interest expense, weighted average interest rates and weighted average debt balances for the years ended December 31, 2016 and 2015:

	Years Ended December 31,	
(dollars in thousands)	**2016**	**2015**
Interest expense, as reported	$ 203,518	$ 215,384
Capitalized interest	252	4,913
Interest expense, excluding impact of capitalized interest	$ 203,770	$ 220,297
Weighted average interest rate - credit facility	-	2.4%
Weighted average interest rate - senior notes	5.9%	5.9%
Total weighted average interest rate	5.9%	5.8%
Weighted average credit facility balance	$ -	$ 195,225
Weighted average senior notes balance	3,181,667	3,350,000
Total weighted average debt balance	$ 3,181,667	$ 3,545,225

The decrease in the weighted average debt balance for the year ended December 31, 2016 as compared to 2015 was due to the repayment of our credit facility using a portion of the proceeds from our October 2015 equity offering and, to a lesser extent, the early redemption of the $600 million outstanding principal amount of our 7.0% Notes. The decrease in interest expense was due to the overall decrease in the weighted average debt balance partially offset by a reduction in capitalized interest period over period.

Loss on extinguishment of debt. We recorded a loss on extinguishment of debt of $56.4 million for the year ended December 31, 2016. This amount includes (i) $19.5 million associated with the make-whole premium paid for the early extinguishment of the 6.5% Notes in December 2016, approximately $7.3 million of related unamortized deferred loan costs and approximately $1.9 million of additional interest on the 6.5% Notes through January 16, 2017, which was paid in December 2016; and (ii) $21.0 million associated with the make-whole premium paid for the early redemption of the 7.0% Notes in September 2016 and approximately $6.7 million of related unamortized deferred loan costs.

Income tax provisions. We recorded an income tax benefit of $876.1 million and income tax expense of $31.4 million for the years ended December 31, 2016 and 2015, respectively. The shift in our income tax provision is primarily due to a significant pre-tax book loss in 2016 as compared to pre-tax book income in 2015. The effective income tax rates for the years ended December 31, 2016 and 2015 were 37.5 percent and 32.3 percent, respectively.

We evaluate changes to our industry, production, market conditions and changes in our forecasted drilling plan by tax jurisdiction. Our material state tax jurisdictions include Texas and New Mexico. In October 2016, we purchased Texas-based assets in the Reliance Acquisition for approximately $1.7 billion, which caused a shift in our projected future apportionment from New Mexico to Texas, which has a lower statutory state tax rate than New Mexico. As such, we recognized an overall state deferred tax benefit of $20.9 million and $9.0 million for 2016 and 2015, respectively.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

Oil and natural gas revenues. Revenue from oil and natural gas operations was $1,803.6 million for the year ended December 31, 2015, a decrease of $856.5 million (32 percent) from $2,660.1 million for the year ended December 31, 2014. This decrease was primarily due to a decrease in realized oil and natural gas prices, offset partially by increased production due to our successful drilling efforts during 2014 and 2015. Specific factors affecting oil and natural gas revenues include the following:

- total oil production was 34,457 MBbl for the year ended December 31, 2015, an increase of 8,138 MBbl (31 percent) from 26,319 MBbl for the year ended December 31, 2014;

- average realized oil price (excluding the effects of derivative activities) was $44.69 per Bbl during the year ended December 31, 2015, a decrease of 46.3 percent from $83.17 per Bbl during the year ended December 31, 2014. For the year ended December 31, 2015, our crude oil price differential relative to NYMEX was $(4.15) per Bbl, or a realization of approximately 91.5 percent, as compared to a crude oil price differential relative to NYMEX of $(9.77) per Bbl, or a realization of approximately 89.5 percent, for 2014. The basis differential between the location of Midland, Texas and Cushing, Oklahoma (NYMEX pricing location) for our oil has a direct effect on our realized oil price. For the years ended December 31, 2015 and 2014, the market basis differential between WTI-Midland and WTI-Cushing (sweet barrel) was a price reduction of $0.41 per Bbl and $6.91 per Bbl, respectively;

- total natural gas production was 106,987 MMcf for the year ended December 31, 2015, an increase of 19,651 MMcf (23 percent) from 87,336 MMcf for the year ended December 31, 2014; and

- average realized natural gas price (excluding the effects of derivative activities) was $2.46 per Mcf during the year ended December 31, 2015, a decrease of 54.4 percent from $5.39 per Mcf during the year ended December 31, 2014. For the years ended December 31, 2015 and 2014, we realized approximately 93.5 percent and 126.2 percent, respectively, of the average NYMEX natural gas prices for the respective periods. Our total natural gas revenues are derived from the value of the natural gas liquids, with the remaining portion coming from the value of the dry natural gas residue. In the past, our liquids-rich natural gas stream and the related value of the natural gas liquids being included in our natural gas revenues resulted in our realized natural gas price (excluding the effects of derivatives) being greater than the related NYMEX natural gas price. However, during the year ended December 31, 2015, our realized natural gas price (excluding the effects of derivatives) fell below the related NYMEX natural gas price primarily due to the average Mont Belvieu price for a blended barrel of natural gas liquids decreasing to $17.80 per Bbl, as compared to $34.58 per Bbl during the year ended December 31, 2014.

During the fourth quarter of 2015, winter weather events across southeast New Mexico had an impact on our production and drilling operations. We experienced power outages, heavy icing and facility freeze-ups across our New Mexico Shelf and Northern Delaware Basin core areas. We estimate that these weather events negatively impacted production for the quarter ended December 31, 2015 by approximately 4.6 MBoepd. Our operations were back to pre-weather levels during mid-January 2016.

Additionally, a third-party natural gas processing plant located in the Northern Delaware Basin became inoperable following an explosion in early December 2015. We estimate that this event negatively impacted production for the quarter ended December 31, 2015 by approximately 1.5 MBoepd. We do not expect the plant to be back to full capacity until sometime during the second quarter of 2016.

Heavy rainfall and flooding during the latter part of September 2014 disrupted our operations, primarily in southeast New Mexico, causing shut-in production, road closures and drilling and completion delays. We estimate this weather-related downtime negatively impacted production for the quarter ended December 31, 2014 by approximately 1.6 MBoepd. We estimate that during the quarter ended December 31, 2014 approximately $1.7 million of repairs was due to this event.

Production expenses. The following table provides the components of our total oil and natural gas production costs for the years ended December 31, 2015 and 2014:

	Years Ended December 31,			
	2015		2014	
(in thousands, except per unit amounts)	Amount	Per Boe	Amount	Per Boe
Lease operating expenses	$ 362,114	$ 6.93	$ 310,284	$ 7.59
Workover costs	27,590	0.53	18,967	0.46
Taxes:				
Ad valorem	22,921	0.44	20,775	0.51
Production	128,734	2.46	188,348	4.61
Total oil and natural gas production expenses	$ 541,359	$ 10.36	$ 538,374	$ 13.17

Among the cost components of production expenses, we have some control over lease operating expenses and workover costs on properties we operate, but production and ad valorem taxes are related to commodity prices.

Lease operating expenses were $362.1 million ($6.93 per Boe) for the year ended December 31, 2015, which was an increase of $51.8 million (17 percent) from $310.3 million ($7.59 per Boe) for the year ended December 31, 2014. The increase in lease operating expenses was primarily due to increased production associated with our wells successfully drilled and completed in 2014 and 2015. The decrease in lease operating expenses per Boe was primarily due to increased production efficiencies resulting in higher volume wells successfully drilled and completed during the years ended December 31, 2015 and 2014.

Workover expenses were approximately $27.6 million and $19.0 million for the years ended December 31, 2015 and 2014, respectively. The increase was primarily related to a higher volume of workovers performed on electrical submersible pumps in the Northern Delaware Basin area where they were utilized more in 2015 as compared to 2014.

Production taxes per unit of production were $2.46 per Boe during the year ended December 31, 2015, a decrease of 47 percent from $4.61 per Boe during the year ended December 31, 2014. The decrease was directly related to the decrease in oil and natural gas prices. Over the same period, our average realized prices per Boe (excluding the effects of derivatives) decreased 47 percent.

Exploration and abandonments expense. The following table provides a breakdown of our exploration and abandonments expense for the years ended December 31, 2015 and 2014:

	Years Ended December 31,	
(in thousands)	2015	2014
Geological and geophysical	$ 9,694	$ 19,268
Exploratory dry hole costs	9,205	44,180
Leasehold abandonments	34,532	217,326
Other	5,416	4,047
Total exploration and abandonments	$ 58,847	$ 284,821

Our geological and geophysical expense for the periods presented above primarily consists of the costs of acquiring and processing geophysical data and core analysis. During the year ended December 31, 2014, we acquired geological and geophysical data related to our Northern Delaware Basin acreage.

Our exploratory dry hole costs during the year ended December 31, 2015 were primarily related to (i) an uneconomic well in our Northern Delaware Basin area that was attempting to establish production in an unconventional zone for the area and (ii) expensing an unsuccessful well, which we did not operate, that was located in our New Mexico Shelf area.

During the year ended December 31, 2015, we recognized leasehold abandonment expense of approximately $34.5 million primarily related to expired and abandoned acreage in our Northern Delaware Basin area where we currently have no intent to drill.

During the fourth quarter of 2014, we completed our assessment of our activity in the outer limits of our Southern Delaware Basin acreage position. Based on our analysis and marginal results of our exploratory wells on this acreage, we have no further plans to invest in this position. Accordingly, we recognized approximately $32.7 million in exploratory dry hole costs and approximately $96.4 million in leasehold abandonments in 2014. In addition to the $32.7 million in exploratory dry holes, we recognized approximately $6.3 million in dry hole costs related to two unsuccessful wells in our New Mexico Shelf area that encountered mechanical issues during drilling and one Northern Delaware Basin well targeting the Brushy Canyon horizon that was testing the outer limits of our acreage.

During the year ended December 31, 2014, we recognized leasehold abandonment expense of approximately $217.3 million primarily related to (i) the Northern Delaware Basin abandonment discussed above and (ii) an $86.0 million charge related to properties in our Midland Basin core area that, based on our historical results and our estimate of reduced future commodity price, we have no future intent to drill based on expected low rates of return. The remaining abandonment charges during 2014 are associated with expiring acreage and acreage determined to be outside of our economically productive reservoirs.

Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the years ended December 31, 2015 and 2014:

	Years Ended December 31,			
	2015		2014	
(in thousands, except per unit amounts)	Amount	Per Boe	Amount	Per Boe
Depletion of proved oil and natural gas properties	$ 1,203,469	$ 23.02	$ 960,931	$ 23.51
Depreciation of other property and equipment	18,323	0.35	17,348	0.42
Amortization of intangible asset - operating rights	1,461	0.03	1,461	0.04
Total depletion, depreciation and amortization	$ 1,223,253	$ 23.40	$ 979,740	$ 23.97
Oil price used to estimate proved oil reserves at period end	$ 46.79		$ 91.48	
Natural gas price used to estimate proved natural gas reserves at period end	$ 2.59		$ 4.35	

Depletion of proved oil and natural gas properties was $1,203.5 million ($23.02 per Boe) for the year ended December 31, 2015, an increase of $242.6 million (25 percent) from $960.9 million ($23.51 per Boe) for the year ended December 31, 2014. The increase in depletion expense was primarily due to increased production associated with new wells that were successfully drilled and completed in 2014 and 2015. The decrease in depletion expense per Boe period over period was primarily due to a reduction in the net book value of our oil and natural gas properties due to non-cash impairment charges of approximately $431.7 million recorded in the fourth quarter of 2014 and increased reserves supported by (i) one or more reliable technologies and (ii) our successful exploratory drilling program, partially offset by decreased proved reserves primarily as a result of lower commodity prices.

The increase in depreciation expense was primarily associated with additional other property and equipment related to buildings and other items.

Impairments of long-lived assets. We periodically review our long-lived assets to be held and used, including proved oil and natural gas properties and their integrated assets, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable, for instance when there are declines in commodity prices or well performance. We review our oil and natural gas properties by depletion base or by individual well for those wells not constituting part of a depletion base. An impairment loss is indicated if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. If the estimated undiscounted future net cash flows are less than the carrying amount of our assets, we recognize an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset.

We calculate the expected undiscounted future net cash flows of our long-lived assets and their integrated assets using management's assumptions and expectations of (i) commodity prices, which are based on the NYMEX strip, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) production volumes, (vi) proved reserves and risk-adjusted probable and possible reserves, and (vii) other sources of income and expenses from integrated assets.

We calculate the estimated fair values of our long-lived assets and their integrated assets using a discounted future cash flow model. Fair value assumptions associated with the calculation of discounted future net cash flows include (i) market estimates of commodity prices, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) production volumes, (vi) estimated proved reserves and risk-adjusted probable and possible reserves, (vii) prevailing market rates of income and expenses from integrated assets and (viii) discount rate. We discount the future net cash flows using a market-based weighted average cost of capital rate determined appropriate at the time.

As a result of the carrying amount of certain of our long-lived assets and their integrated assets being less than their expected undiscounted future net cash flows, we recognized a non-cash charge against earnings for the amount by which the carrying amount exceeded the estimated fair value of the assets. For the year ended December 31, 2015, this amount was approximately $60.5 million and was primarily attributable to properties in our eastern Midland Basin area.

As a result of the carrying amount of certain of our long-lived assets being less than their expected undiscounted future net cash flows, we recognized a non-cash charge against earnings of $447.2 million during the year ended December 31, 2014, which was primarily attributable to (i) non-core properties in our Northern Delaware Basin area, (ii) properties producing from the Grayburg San Andres reservoir in our New Mexico Shelf area and (iii) properties producing from the Canyon and Wolfcamp reservoirs primarily in Irion and Glasscock counties in our Midland Basin core area.

General and administrative expenses. The following table provides components of our general and administrative expenses for the years ended December 31, 2015 and 2014:

	Years Ended December 31,			
	2015		2014	
(in thousands, except per unit amounts)	Amount	Per Boe	Amount	Per Boe
General and administrative expenses	$ 186,880	$ 3.58	$ 175,934	$ 4.30
Less: Operating fee reimbursements	(19,219)	(0.37)	(18,903)	(0.46)
Non-cash stock-based compensation	63,073	1.21	47,130	1.15
Total general and administrative expenses	$ 230,734	$ 4.42	$ 204,161	$ 4.99

General and administrative expenses were approximately $230.7 million ($4.42 per Boe) for the year ended December 31, 2015, an increase of $26.5 million (13 percent) from $204.2 million ($4.99 per Boe) for the year ended December 31, 2014. The increase in general and administrative expenses was primarily due to an increase in the number of employees and related personnel expenses. The increase in non-cash stock-based compensation was primarily due to performance units granted during January 2015. Due to lower commodity prices and a reduction in activity, we began to slow our hiring rate during 2015. The decrease in total general and administrative expenses per Boe was primarily due to increased production from our wells successfully drilled and completed in 2014 and 2015, partially offset by an increase in the number of employees and related personnel expenses in order to manage our activities.

We receive fees for the operation of jointly-owned oil and natural gas properties during the drilling and production phases and record such reimbursements as reductions of general and administrative expenses in the consolidated statements of operations. We earned reimbursements of $19.2 million and $18.9 million during the years ended December 31, 2015 and 2014, respectively.

Gain (loss) on derivatives. The following table sets forth the gain on derivatives for the years ended December 31, 2015 and 2014:

(in thousands)	Years Ended December 31, 2015	Years Ended December 31, 2014
Gain on derivatives:		
Oil derivatives	$ 675,303	$ 869,421
Natural gas derivatives	24,449	21,496
Total	$ 699,752	$ 890,917

The following table represents our net cash receipts from (payments on) derivatives for the years ended December 31, 2015 and 2014:

(in thousands)	Years Ended December 31, 2015	Years Ended December 31, 2014
Net cash receipts from (payments on) derivatives:		
Oil derivatives	$ 597,297	$ 76,335
Natural gas derivatives	35,619	(4,352)
Total	$ 632,916	$ 71,983

Our earnings are affected by the changes in value of our derivatives portfolio between periods and the related cash settlements of those derivatives, which could be significant. To the extent the future commodity price outlook declines between measurement periods, we will have mark-to-market gains, while to the extent future commodity price outlook increases between measurement periods, we will have mark-to-market losses. See Note 7 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding significant judgments made in classifying financial instruments in the fair value hierarchy.

Gain (loss) on disposition of assets, net. In December 2015, we completed an acreage exchange with Clayton Williams Energy, Inc. that consolidated acres into a concentrated, operated position in our Southern Delaware Basin core area. We recognized a loss on disposition of assets of approximately $50.0 million related to the acreage exchange.

Interest expense. The following table sets forth interest expense, weighted average interest rates and weighted average debt balances for the years ended December 31, 2015 and 2014:

(dollars in thousands)	Years Ended December 31, 2015	Years Ended December 31, 2014
Interest expense	$ 215,384	$ 216,661
Capitalized interest	4,913	2,282
Interest expense, excluding impact of capitalized interest	$ 220,297	$ 218,943
Weighted average interest rate - credit facility	2.4%	2.4%
Weighted average interest rate - senior notes	5.9%	5.9%
Total weighted average interest rate	5.8%	5.8%
Weighted average credit facility balance	$ 195,225	$ 144,966
Weighted average senior notes balance	3,350,000	3,350,000
Total weighted average debt balance	$ 3,545,225	$ 3,494,966

The increase in the weighted average debt balance during the year ended December 31, 2015 as compared to the corresponding period in 2014 was due to 2015 capital expenditures in excess of our cash flows, primarily related to our drilling program and acquisitions, offset in part by cash received from our March 2015 and October 2015 equity offerings.

Loss on extinguishment of debt. In May 2014, we amended and restated our credit facility. We recorded a loss on extinguishment of debt of $4.3 million for the year ended December 31, 2014, representing the proportional amount of unamortized deferred loan costs associated with banks with lesser commitments in the amended credit facility syndicate.

Income tax provisions. We recorded income tax expense of $31.4 million and $317.8 million for the years ended December 31, 2015 and 2014, respectively. The effective income tax rate for the years ended December 31, 2015 and 2014 were 32.3 percent and 37.1 percent, respectively.

We evaluate changes to our industry, production, market conditions and changes in our forecasted drilling plan by tax jurisdiction. As such, we recognized an overall deferred tax benefit of $9.0 million and $7.9 million for 2015 and 2014, respectively. This deferred tax benefit recorded in 2015, was the primary driver for our lower effective tax rate as compared to 2014.

Capital Commitments, Capital Resources and Liquidity

Capital commitments. Our primary needs for cash are development, exploration and acquisition of oil and natural gas assets, payment of contractual obligations and working capital obligations. Funding for these cash needs may be provided by any combination of internally-generated cash flow, financing under our credit facility, proceeds from the disposition of assets or alternative financing sources, as discussed in "— Capital resources" below.

Oil and natural gas properties. Our costs incurred on oil and natural gas properties, excluding acquisitions and asset retirement obligations, during the years ended December 31, 2016, 2015 and 2014 totaled $1.1 billion, $1.8 billion and $2.5 billion, respectively. The decrease is primarily related to our intent to adjust our capital spending to be within our cash flow, excluding unbudgeted acquisitions. The primary reason for the differences in the costs incurred and cash flow expenditures was our issuance of approximately 2.2 million shares of common stock related to our March 2016 acquisition, our issuance of approximately 3.9 million shares of common stock related to our Reliance Acquisition and timing of payments. The 2016 expenditures were primarily funded in part from (i) cash flows from operations, (ii) proceeds from our February 2016 divestiture, (iii) our issuance of approximately 2.2 million shares of common stock related to our March 2016 acquisition, (iv) proceeds from our August 2016 equity offering and (v) our issuance of approximately 3.9 million shares of common stock related to our Reliance Acquisition.

2017 capital budget. In February 2017, we announced our updated 2017 capital budget, excluding acquisitions, of approximately $1.8 billion with expected capital spending to range between $1.6 billion and $1.8 billion. Approximately 90 percent of capital will be directed to drilling and completion activity. Our 2017 capital program is expected to continue focusing on extended length lateral drilling. Our 2017 capital budget, based on our current expectations of commodity prices and costs, is expected to be within our cash flows. However, if we were to outspend our cash flows, we believe we could use our (i) cash on hand, (ii) credit facility and (iii) other financing sources to fund any cash flow deficits. The actual amount and timing of our expenditures may differ materially from our estimates as a result of, among other things, actual drilling results, the timing of expenditures by third parties on projects that we do not operate, the costs of drilling rigs and other services and equipment, regulatory, technological and competitive developments, commodity prices, leverage metrics and industry conditions. In addition, under certain circumstances, we may consider increasing, decreasing or reallocating our capital spending plans.

Other than the customary purchase of leasehold acreage, our capital budgets are exclusive of acquisitions. We do not have a specific acquisition budget, since the timing and size of acquisitions are difficult to forecast. We evaluate opportunities to purchase or sell oil and natural gas properties in the marketplace and could participate as a buyer or seller of properties at various times. We seek to acquire oil and natural gas properties that provide opportunities for the addition of reserves and production through a combination of development, high-potential exploration and control of operations that will allow us to apply our operating expertise.

Acquisitions. The following table reflects our expenditures for acquisitions of proved and unproved properties for the years ended December 31, 2016, 2015 and 2014:

	Years Ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Property acquisition costs:			
Proved	$ 981,855	$ 57,190	$ 99,362
Unproved	1,154,423	206,214	292,363
Total property acquisition costs (a)	$ 2,136,278	$ 263,404	$ 391,725

(a) Included in the property acquisition costs above are budgeted unproved leasehold acreage acquisitions of $30.4 million, $69.1 million and $89.1 million for the years ended December 31, 2016, 2015 and 2014, respectively. For the year ended December 31, 2016, our unbudgeted acquisitions are primarily comprised of approximately $2.1 billion of property acquisition costs related to our March and October 2016 acquisitions.

Contractual obligations. We had the following contractual obligations at December 31, 2016:

(in thousands)	Payments Due by Period Total	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years
Long-term debt (a)	$ 2,750,000	$ -	$ -	$ -	$ 2,750,000
Cash interest expense on debt (b)	965,396	176,219	289,000	289,000	211,177
Derivative liabilities (c)	177,949	82,079	95,870	-	-
Asset retirement obligations (d)	130,390	10,035	9,167	11,857	99,331
Employment agreements with officers (e)	7,395	7,395	-	-	-
Purchase obligations (f)	318,479	56,649	118,522	45,439	97,869
Operating lease obligations (g)	33,408	8,988	14,364	9,054	1,002
Total contractual obligations	$ 4,383,017	$ 341,365	$ 526,923	$ 355,350	$ 3,159,379

(a) See Note 9 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for information regarding future interest payment obligations on our long-term debt. The amounts included in the table above represent principal maturities only.

(b) Cash interest expense on our senior notes is estimated assuming no principal repayment until their maturity dates. Also included in the “Less than 1 year” column is accrued interest at December 31, 2016 of approximately $31.7 million.

(c) Derivative obligations represent commodity derivatives that were valued at December 31, 2016. The ultimate settlement amounts of our derivative obligations are unknown because they are subject to continuing market risk. See “Item 7A. Quantitative and Qualitative Disclosures About Market Risk” and Note 8 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding our derivative obligations.

(d) Amounts represent costs related to expected oil and natural gas property abandonments related to proved reserves by period, net of any future accretion.

(e) Represents amounts of cash compensation we are obligated to pay to our officers under employment agreements assuming such employees continue to serve the entire term of their employment agreement and their cash compensation is not adjusted.

(f) Relates to purchase agreements we have entered into including daywork drilling contracts, water commitment agreements, throughput volume delivery commitments, power commitments, fixed asset commitments and maintenance commitments.

(g) We lease vehicles, equipment and office facilities under non-cancellable operating leases.

Off-balance sheet arrangements. Currently, we do not have any material off-balance sheet arrangements.

Capital resources. Our primary sources of liquidity have been cash flows generated from (i) operating activities, (ii) borrowings under our credit facility and (iii) proceeds from bond and equity offerings. In February 2017, we announced our updated 2017 capital budget, excluding acquisitions, of approximately $1.8 billion with expected capital spending to range between $1.6 billion and $1.8 billion. Approximately 90 percent of capital will be directed to drilling and completion activity. Our 2017 capital program is expected to continue focusing on extended length lateral drilling. Our 2017 capital budget, based on our current expectations of commodity prices and costs, is expected to be within our cash flows. However, if we were to outspend our cash flows, we believe we could use our (i) cash on hand, (ii) credit facility and (iii) other financing sources to fund any cash flow deficits. The actual amount and timing of our expenditures may differ materially from our estimates as a result of, among other things, actual drilling results, the timing of expenditures by third parties on projects that we do not operate, the costs of drilling rigs and other services and equipment, regulatory, technological and competitive developments, commodity prices, leverage metrics and industry conditions. In addition, under certain circumstances, we may consider increasing, decreasing or reallocating our capital spending plans.

The following table summarizes our net increase (decrease) in cash and cash equivalents for the years ended December 31, 2016, 2015 and 2014:

	Years Ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Net cash provided by operating activities	$ 1,384,448	$ 1,530,421	$ 1,745,770
Net cash used in investing activities	(2,224,656)	(2,602,641)	(2,617,979)
Net cash provided by financing activities	664,919	1,300,749	872,209
Net increase (decrease) in cash and cash equivalents	$ (175,289)	$ 228,529	$ -

Cash flow from operating activities. The decrease in operating cash flows during the year ended December 31, 2016 as compared to 2015 was primarily due to (i) a decrease in oil and natural gas revenues of approximately $168.6 million and (ii) approximately $95.2 million of negative variances in operating assets and liabilities, partially offset by (i) approximately $90.1 million decrease in cash production expense, (ii) an increase in operating cash flow of approximately $13.4 million due to a cash tax benefit of approximately $11.7 million for the year ended December 31, 2016 compared to cash tax expense of approximately $1.7 million during 2015 and (iii) a decrease in cash interest expense of approximately $11.8 million.

The decrease in operating cash flows during the year ended December 31, 2015 as compared to 2014 was primarily due to (i) a decrease in oil and natural gas revenues of approximately $856.6 million and (ii) a cash increase in general and administrative expense of approximately $10.6 million, offset in part by (i) approximately $632.9 million of receipts from derivatives during 2015 compared to receipts of approximately $72.0 million during 2014, (ii) approximately $78.6 million of positive variances in operating assets and liabilities and (iii) a decrease in cash tax expense of approximately $19.9 million.

Our net cash provided by operating activities included a reduction of approximately $60.1 million, a benefit of approximately $35.1 million and a reduction of approximately $43.5 million for the years ended December 31, 2016, 2015 and 2014, respectively, associated with changes in operating assets and liabilities. Changes in operating assets and liabilities adjust for the timing of receipts and payments of actual cash.

Cash flow used in investing activities. During the years ended December 31, 2016, 2015 and 2014, we invested approximately $2.4 billion, $2.4 billion and $2.6 billion, respectively, for capital expenditures on oil and natural gas properties and acquisitions. The primary reason for the differences in the costs incurred and cash flow expenditures is the timing of payments. The 2016 expenditures were funded in part from (i) proceeds from our February 2016 divestiture, (ii) our issuance of approximately 2.2 million shares of common stock related to our March 2016 acquisition, (iii) proceeds from our August 2016 equity offering and (iv) our issuance of approximately 3.9 million shares of common stock related to our Reliance Acquisition. The 2015 and 2014 expenditures were funded in part from borrowings under our credit facility and our equity offerings in 2014 and 2015.

Cash flows used in investing activities decreased during the year ended December 31, 2016 as compared to 2015, primarily due to (i) proceeds from the disposition of assets of approximately $332.0 million during 2016, (ii) a decrease of approximately $46.5 million in amounts invested in oil and natural gas properties from 2015 to 2016, (iii) contributions to our equity method investments of approximately $55.8 million during 2016 compared to contributions of approximately $91.3 million during 2015 and (iv) approximately $60.7 million invested in other property and equipment during 2016 compared to approximately $67.7 million in 2015, partially offset by a 2016 cash outflow for funds held in escrow of $43.0 million related to our January 2017 asset acquisition.

Cash flows used in investing activities decreased during the year ended December 31, 2015 as compared to 2014, primarily due to a decrease of approximately $111.2 million in amounts invested in oil and natural gas properties from 2014 to 2015, partially offset by (i) contributions to our equity method investments of approximately $91.3 million during 2015 compared to contributions of approximately $30.1 million during 2014 and (ii) approximately $67.7 million invested in other property and equipment during 2015 compared to approximately $34.3 million in 2014.

Cash flow from financing activities. Below is a description of our financing activities. During 2016, 2015 and 2014 we completed the following significant capital markets activities:

- In December 2016, we issued $600 million in aggregate principal amount of 4.375% senior notes due 2025 at par, for which we received net proceeds of approximately $592.1 million. We used the net proceeds from the offering to fund the satisfaction and discharge of our obligations under the indenture of the $600 million outstanding principal amount of our 6.5% Notes at a price equal to 103.25 percent of par. The early extinguishment price included the make-whole premium of $19.5 million.

- In September 2016, we redeemed the $600 million outstanding principal amount of our 7.0% Notes at a price equal to 103.5 percent of par. The redemption price included the make-whole premium for the early redemption of $21.0 million.

- In August 2016, we issued approximately 10.4 million shares of our common stock in a public offering at $130.90 per share and received net proceeds of approximately $1.3 billion. We used a portion of the net proceeds to finance part of the cash portion of the purchase price for the Reliance Acquisition and to fund part of the early redemption of the 7.0% Notes, and the remainder for general corporate purposes.

- In October 2015, we issued approximately 8.9 million shares of our common stock in a public offering at $92.50 per share and received net proceeds of approximately $794.2 million. We used a portion of the net proceeds from this offering to repay all outstanding borrowings under our credit facility and used the remainder for general corporate purposes and for funding of our 2016 acquisitions.

- In March 2015, we issued 6.9 million shares of our common stock in a public offering at $107.49 per share and received net proceeds of approximately $741.5 million. We used a portion of the net proceeds from this offering to repay all outstanding borrowings under our credit facility and the remainder for general corporate purposes.

- In May 2014, we issued approximately 7.5 million shares of our common stock in a public offering at $129.00 per share and received net proceeds of approximately $932.0 million. We used a portion of the net proceeds from this offering to repay all outstanding borrowings under our credit facility and used the remainder for general corporate purposes, including funding our drilling program and capital commitments associated with the midstream joint venture.

At December 31, 2016, we had unused commitments on our credit facility of $2.5 billion. The maturity date of the credit facility is May 9, 2019.

Advances on our credit facility bear interest, at our option, based on (i) the prime rate of JPMorgan Chase Bank ("JPM Prime Rate") (3.75 percent at December 31, 2016) or (ii) a Eurodollar rate (substantially equal to the LIBOR). The credit facility's interest rates of Eurodollar rate advances and JPM Prime Rate advances varied, with interest margins ranging from 125 to 225 basis points and 25 to 125 basis points, respectively, per annum depending on the debt balance outstanding on our credit facility. Under our current credit facility, we pay commitment fees on the unused portion of the available commitment ranging from 30 to 37.5 basis points per annum, depending on utilization of the borrowing base.

In conducting our business, we may utilize various financing sources, including the issuance of (i) fixed and floating rate debt, (ii) convertible securities, (iii) preferred stock, (iv) common stock and (v) other securities. Over the last three years, we have demonstrated our use of capital markets by issuing senior unsecured debt and common stock. There are no assurances that we can access capital markets in the future to obtain additional funding, if needed, and at what cost and terms. We may also sell assets and issue securities in exchange for oil and natural gas assets or interests in oil and natural gas companies. Additional securities may be of a class senior to common stock with respect to such matters as dividends and liquidation rights and may also have other rights and preferences as determined from time-to-time by our board of directors. Utilization of some of these financing sources may require approval from the lenders under our credit facility.

Liquidity. Our principal sources of liquidity are cash on hand and available borrowing capacity under our credit facility. At December 31, 2016, we had approximately $53.3 million of cash on hand. Subsequent to December 31, 2016, our cash position will be increased by our disposition of ACC for approximately $802.8 million and reduced by our Northern Delaware Basin acquisition for approximately $107.0 million, resulting in a net increase of $695.8 million.

At December 31, 2016, our commitments from our bank group were $2.5 billion. We expect we will maintain our $2.5 billion in commitments until our next scheduled redetermination in May 2017. At December 31, 2016, our borrowing base was $2.8 billion. There is no assurance that our borrowing base will not be reduced, which could affect our liquidity. Upon a subsequent redetermination, our borrowing base could be substantially reduced.

We may from time to time seek to retire or purchase our outstanding debt through cash purchases and/or exchanges for other debt or equity securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Debt ratings. We receive debt credit ratings from S&P Global Ratings ("S&P") and Moody's Investors Service, Inc. ("Moody's"), which are subject to regular reviews. S&P's corporate rating for us is "BB+" with a positive outlook. Moody's corporate rating for us is "Ba1" with a stable outlook. S&P and Moody's consider many factors in determining our ratings including: the industry in which we operate, production growth opportunities, liquidity, debt levels and asset and reserve mix. A reduction in our debt ratings could negatively affect our ability to obtain additional financing or the interest rate, fees and other terms associated with such additional financing.

A downgrade in our credit ratings could negatively impact our costs of capital and our ability to effectively execute aspects of our strategy. Further, a downgrade in our credit ratings could affect our ability to raise debt in the public debt markets, and the cost of any new debt could be much higher than our outstanding debt. These and other impacts of a downgrade in our credit ratings could have a material adverse effect on our business, financial condition and results of operations.

As of the filing of this Annual Report, no changes in our credit ratings have occurred since December 31, 2016; however, we cannot be assured that our credit ratings will not be downgraded in the future.

Book capitalization and current ratio. Our net book capitalization at December 31, 2016 was $10.2 billion, consisting of $0.1 billion of cash and cash equivalents, debt of $2.7 billion and stockholders' equity of $7.6 billion. Our net book capitalization at December 31, 2015 was $10.0 billion, consisting of $0.2 billion of cash and cash equivalents, debt of $3.3 billion and stockholders' equity of $6.9 billion. Our ratio of net debt to net book capitalization was 26 percent and 31 percent at December 31, 2016 and 2015, respectively. Our ratio of current assets to current liabilities was 0.73 to 1.0 at December 31, 2016 as compared to 2.20 to 1.0 at December 31, 2015.

Inflation and changes in prices. Our revenues, the value of our assets, and our ability to obtain bank financing or additional capital on attractive terms have been and will continue to be affected by changes in commodity prices and the costs to produce our reserves. Commodity prices are subject to significant fluctuations that we are unable to control or predict. During the year ended December 31, 2016, we received an average of $39.90 per barrel of oil and $2.23 per Mcf of natural gas before consideration of commodity derivative contracts compared to $44.69 and $83.17 per barrel of oil and $2.46 and $5.39 per Mcf of natural gas in the years ended December 31, 2015 and 2014, respectively. Although certain of our costs are affected by general inflation, inflation does not normally have a significant effect on our business.

Critical Accounting Policies and Practices

Our historical consolidated financial statements and related notes to consolidated financial statements contain information that is pertinent to our management's discussion and analysis of financial condition and results of operations. Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires that our management make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. However, the accounting principles used by us generally do not change our reported cash flows or liquidity. Interpretation of the existing rules must be done and judgments made on how the specifics of a given rule apply to us.

In management's opinion, the more significant reporting areas impacted by management's judgments and estimates are the choice of accounting method for oil and natural gas activities, oil and natural gas reserve estimation, asset retirement obligations, impairment of long-lived assets, valuation of stock-based compensation, valuation of business combinations, valuation of financial derivative instruments and income taxes. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists and historical experience in similar matters. Actual results could differ from the estimates as additional information becomes known.

Successful Efforts Method of Accounting

We utilize the successful efforts method of accounting for our oil and natural gas exploration and development activities. Under this method, exploration expenses, including geological and geophysical costs, lease rentals and exploratory dry holes, are charged against income as incurred. Costs of successful wells and related production equipment, undeveloped leases and developmental dry holes are capitalized. Exploratory drilling costs are initially capitalized, but are charged to expense if and when the well is determined not to have found proved reserves. Generally, a gain or loss is recognized when producing fields are sold. This accounting method may yield significantly different results than the full cost method of accounting.

The application of the successful efforts method of accounting requires management's judgment to determine the proper designation of wells as either developmental or exploratory, which will ultimately determine the proper accounting treatment of costs of dry holes. Once a well is drilled, the determination that proved reserves have been discovered may take considerable time, and requires both judgment and application of industry experience. The evaluation of oil and natural gas leasehold acquisition costs included in unproved properties requires management's judgment to estimate the fair value of such properties. Drilling activities in an area by other companies may also effectively condemn our leasehold positions.

Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Individually significant non-producing properties or projects are periodically assessed for impairment of value by considering future drilling plans, the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects.

Depletion of capitalized drilling and development costs of oil and natural gas properties is computed using the unit-of-production method on total estimated proved developed oil and natural gas reserves. Depletion of producing leaseholds is based on the unit-of-production method using our total estimated proved reserves. In arriving at rates under the unit-of-production method, the quantities of recoverable oil and natural gas are established based on estimates made by our geologists and engineers and independent engineers. Service properties, equipment and other assets are depreciated using the straight-line method over estimated useful lives of two to 39 years. Upon sale or retirement of depreciable or depletable property, the cost and related accumulated depreciation and depletion are eliminated from the accounts and the resulting gain or loss is recognized.

Oil and Natural Gas Reserves and Standardized Measure of Discounted Net Future Cash Flows

This report presents estimates of our proved reserves as of December 31, 2016, which have been prepared and presented in accordance with SEC guidelines. The pricing that was used for estimates of our reserves as of December 31, 2016 was based on an unweighted average twelve month WTI posted price of $39.25 per Bbl for oil and a Henry Hub spot natural gas price of $2.48 per MMBtu for natural gas.

Our independent engineers and technical staff prepare the estimates of our oil and natural gas reserves and associated future net cash flows. Even though our independent engineers and technical staff are knowledgeable and follow authoritative guidelines for estimating reserves, they must make a number of subjective assumptions based on professional judgments in developing the reserve estimates. Reserve estimates are updated at least annually and consider recent production levels and other technical information about each field. Periodic revisions to the estimated reserves and future net cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, oil and natural gas prices, cost changes, technological advances, new geological or geophysical data, or other economic factors. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly alter future depletion and result in impairment of long-lived assets that may be material.

It should not be assumed that the Standardized Measure included in this report as of December 31, 2016 is the current market value of our estimated proved reserves. In accordance with SEC requirements, we based the 2016 Standardized Measure on a 12-month average of commodity prices on the first day of the month and prevailing costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs utilized in the estimate. See “Item 1A. Risk Factors” and “Item 2. Properties” for additional information regarding estimates of proved reserves.

Our estimates of proved reserves materially impact depletion expense. If the estimates of proved reserves decline, the rate at which we record depletion expense will increase, reducing future earnings. Such a decline may result from lower commodity prices, which may make it uneconomical to drill for and produce higher cost fields. In addition, a decline in proved reserve estimates may impact the outcome of our assessment of our proved properties for impairment.

Asset Retirement Obligations

There are legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and the normal operation of a long-lived asset. The primary impact of this relates to oil and natural gas wells on which we have a legal obligation to plug and abandon. We record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and, generally, a corresponding increase in the carrying amount of the related long-lived asset. The determination of the fair value of the liability requires us to make numerous judgments and estimates, including judgments and estimates related to future costs to plug and abandon wells, future inflation rates and estimated lives of the related assets. When the judgments used to estimate the initial fair value of the asset retirement obligation change, an adjustment is recorded to both the obligation and the carrying amount of the related long-lived asset.

Impairment of Long-Lived Assets

All of our long-lived assets are monitored for potential impairment when circumstances indicate that the carrying value of an asset may be greater than management’s estimates of its future net cash flows, including cash flows from proved reserves, risk-adjusted probable and possible reserves, and integrated assets. If the carrying value of the long-lived assets exceeds the sum of estimated undiscounted future net cash flows, an impairment loss is recognized for the difference between the estimated fair value and the carrying value of the assets. The evaluations involve a significant amount of judgment since the results are based on estimated future events, such as future sales prices for oil and natural gas, future costs to produce these products, estimates of future oil and natural gas reserves to be recovered and the timing thereof, the economic and regulatory climates, cash flows from integrated assets and other factors. The need to test an asset for impairment may result from significant declines in sales prices or downward revisions in estimated quantities of oil and natural gas reserves. Any assets held for sale are reviewed for impairment when we approve the plan to sell. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges will be recorded. At December 31, 2016, the Company’s estimates of commodity prices for purposes of determining undiscounted future cash flows, which are based on the NYMEX strip, ranged from a 2017 price of $56.19 per barrel of oil to a 2024 price of $57.41 per barrel of oil. Similarly, gas prices ranged from a 2017 price of $3.61 per Mcf of natural gas decreasing to a 2020 price of $2.88 per Mcf partially recovering to a 2024 price of $3.38 per Mcf of natural gas. Commodity prices for this purpose were held flat after 2024.

Valuation of Stock-Based Compensation

In accordance with GAAP, we calculate the fair value of stock-based compensation using various valuation methods. The valuation methods require the use of estimates to derive the inputs necessary to determine fair value. We utilize (a) the Black-Scholes option pricing model to measure the fair value of stock options, (b) the average of the high and low stock price on the date of grant for the fair value of restricted stock awards and (c) the Monte Carlo simulation method for the fair value of performance unit awards. The significant assumptions used in these models include expected volatility, expected term, risk-free interest rate, forfeiture rate, and the probability of meeting performance targets. Each of these valuation methods were chosen as management believes they give the best estimate of fair value for the respective stock-based awards. See Note 6 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding our stock-based compensation.

Valuation of Business Combinations

In connection with a purchase business combination, the acquiring company must record assets acquired and liabilities assumed based on fair values as of the acquisition date. Deferred taxes must be recorded for any differences between the assigned values and tax bases of assets and liabilities. Any excess of purchase price over amounts assigned to assets and liabilities is recorded as goodwill. The amount of goodwill recorded in any particular business combination can vary significantly depending upon the value attributed to assets acquired and liabilities assumed.

In estimating the fair values of assets acquired and liabilities assumed, we make various assumptions. The most significant assumptions related to the estimated fair values assigned to proved and unproved oil and natural gas properties and integrated assets. To estimate the fair values of these properties, we utilize estimates of oil and natural gas reserves. We make future price assumptions to apply to the estimated reserves quantities acquired and estimate future operating and development costs to arrive at estimates of future net cash flows. For estimated proved reserves, the future net cash flows were discounted using a market-based weighted average cost of capital rates determined appropriate at the time of the acquisition. The market-based weighted average cost of capital rates are subject to additional project-specific risking factors. To estimate the fair value of unproved, we apply risk-weighting factors of the future net cash flows of unproved reserves, or we may evaluate acreage values through recent market transactions in the area.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. A higher fair value assigned to a property results in a higher depletion expense, which results in lower net earnings. Fair values are based on estimates of future commodity prices, reserves quantities, operating expenses and development costs. This increases the likelihood of impairment if future commodity prices or reserves quantities are lower than those originally used to determine fair value or if future operating expenses or development costs are higher than those originally used to determine fair value. Impairment would have no effect on cash flows but would result in a decrease in net income for the period in which the impairment is recorded.

Valuation of Nonmonetary Exchanges

In connection with a nonmonetary exchange, we must record assets received based on the fair value of assets surrendered. Any resulting difference between the fair value of the assets surrendered and their carrying value is recorded as a gain or loss in the consolidated statement of operations.

In estimating the fair values of assets surrendered, we make various assumptions. The most significant assumptions are related to the estimated fair values assigned to proved and unproved oil and natural gas properties, similar to our valuation of the fair value of oil and natural gas assets acquired a business combination.

Estimated fair values assigned to assets exchanged can have a significant effect on results of operations. A lower fair value assigned to a property disposed may result in a higher loss, which affects net earnings. Fair values are based on estimates of future commodity prices, reserves quantities, operating expenses and development costs. This increases the likelihood of impairment if future commodity prices or reserves quantities are lower than those originally used to determine fair value or if future operating expenses or development costs are higher than those originally used to determine fair value. Impairment would have no effect on cash flows but would result in a decrease in net income for the period in which the impairment is recorded.

Valuation of Financial Derivative Instruments

In order to reduce commodity price uncertainty and increase cash flow predictability relating to the marketing of our oil and natural gas, we enter into commodity price hedging arrangements with respect to a portion of our expected production. In addition, we have used derivative instruments in connection with acquisitions and certain price-sensitive projects. Management exercises significant judgment in determining the types of instruments to be used, production volumes to be hedged, prices at which to hedge and the counterparties' creditworthiness. All derivative instruments are reflected at fair value in our consolidated balance sheets.

Our open commodity derivative instruments were in a net liability position with a fair value of $174.4 million at December 31, 2016. In order to determine the fair value at the end of each reporting period, we compute discounted cash flows for the duration of each commodity derivative instrument using the terms of the related contract. Inputs consist of published forward commodity price curves as of the date of the estimate. We compare these prices to the price parameters contained in our hedge contracts to determine estimated future cash inflows or outflows. We then discount the cash inflows or outflows using a combination of published LIBOR rates and Eurodollar futures rates. The fair values of our commodity derivative assets and liabilities include a measure of credit risk based on average published yields by credit rating. In addition, for collars, we estimate the option value of the contract floors and ceilings using an option pricing model which takes into account market volatility, market prices and contract parameters.

Changes in the fair values of our commodity derivative instruments have a significant impact on our net income because we follow mark-to-market accounting and recognize all gains and losses on such instruments in earnings in the period in which they occur. For the year ended December 31, 2016, we reported a $368.7 million loss on commodity derivative instruments.

We compare our estimates of the fair values of our commodity derivative instruments with those provided by our counterparties. There have been no significant differences.

Income Taxes

Our provision for income taxes includes both federal and state taxes in jurisdictions in which we operate. We estimate our overall tax rate using a combination of the federal tax rate and a blend of enacted state tax rates. Acquisitions or dispositions of assets and changes in drilling plan by tax jurisdiction could change the apportionment of our state taxes, which would impact our overall tax rate.

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, which are based on numerous judgments and assumptions inherent in the determination of future taxable income, at the end of each period as well as the effects of tax rate changes and tax credits. Adjustments related to these estimates are recorded in our tax provision in the period in which we finalize our income tax returns. Material changes to our tax accruals may occur in the future based on audits, changes in legislation or resolution of pending matters.

Recent Accounting Pronouncements

In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)," which outlines a new, single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized. The new model will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services.

In August 2015, the FASB issued ASU No. 2015-14, "Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date," which deferred the effective date of ASU 2014-09 by one year. That new standard is now effective for annual reporting periods beginning after December 15, 2017. We expect to use the modified retrospective method to adopt the standard, meaning the cumulative effect of initially applying the standard will be recognized in the most current period presented in the financial statements. We are substantially complete with our internal evaluation of the adoption of this standard and do not expect this new guidance will have a material impact on our consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02, "Leases (Topic 842)," which supersedes current lease guidance. The new lease standard requires all leases with a term greater than one year to be recognized on the balance sheet while maintaining substantially similar classifications for finance and operating leases. Lease expense recognition on the income statement will be effectively unchanged. This guidance is effective for reporting periods beginning after December 15, 2018 and early adoption is permitted. We do not plan to early adopt the standard. We enter into lease agreements to support our operations. These agreements are for leases on assets such as office space, vehicles, field services and well equipment and drilling rigs. We are currently in the process of reviewing all contracts that could be applicable to this new guidance. We believe this new guidance will have a moderate impact to our consolidated balance sheet due to the recognition of lease-related assets and liabilities that were not previously recognized.

In March 2016, the FASB issued ASU No. 2016-09, "Compensation–Stock Compensations (Topic 718): Improvements to Employee Share-based Payment Accounting," which changes the accounting and presentation for share-based payment arrangements in the following areas: (i) recognition in the statement of operations of excess tax benefits and deficiencies; (ii) cash flow presentation of excess tax benefits and deficiencies; (iii) minimum statutory withholding thresholds and the classification on the cash flow statement of the withheld amounts; and (iv) an accounting policy election to recognize forfeitures as they occur. This guidance is effective for reporting periods beginning after December 15, 2016 and early adoption is permitted.

We will adopt ASU No. 2016-09 during the first quarter of 2017. The adoption will not have a material impact on prior period consolidated financial statements. We will elect to account for forfeitures of share-based payments as they occur. As of December 31, 2016, we had not recorded compensation expense of approximately $8.2 million for our forfeiture estimate. We will prospectively classify excess tax benefits and deficiencies as operating activities on the consolidated statement of cash flows and will prospectively record as a discrete item in our income tax provision in the consolidated income statement. We will also recognize all excess tax benefits not previously realized, which totaled approximately $4.7 million as of December 31, 2016. Upon adoption, we will record a cumulative-effect adjustment, which will decrease retained earnings by approximately $0.5 million, increase additional paid-in capital by approximately $8.2 million, and decrease net deferred income taxes by approximately $7.7 million.

In June 2016, the FASB issued ASU No. 2016-13, "Financial Instruments–Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments," which replaces the current "incurred loss" methodology for recognizing credit losses with an "expected loss" methodology. This new methodology requires that a financial asset measured at amortized cost be presented at the net amount expected to be collected. This standard is intended to provide more timely decision-useful information about the expected credit losses on financial instruments. This guidance is effective for fiscal years beginning after December 15, 2019, and early adoption is allowed as early as fiscal years beginning after December 15, 2018. We do not believe this new guidance will have a material impact on our consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to a variety of market risks, including credit risk, commodity price risk and interest rate risk. We address these risks through a program of risk management which includes the use of derivative instruments. The following quantitative and qualitative information is provided about financial instruments to which we are a party at December 31, 2016, and from which we may incur future gains or losses from changes in market interest rates or commodity prices and losses from extension of credit. We do not enter into derivative or other financial instruments for speculative or trading purposes.

Hypothetical changes in interest rates and commodity prices chosen for the following estimated sensitivity analysis are considered to be reasonably possible near-term changes generally based on consideration of past fluctuations for each risk category. However, since it is not possible to accurately predict future changes in interest rates and commodity prices, these hypothetical changes may not necessarily be an indicator of probable future fluctuations.

Credit risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our oil and natural gas production, which we market to energy marketing companies and refineries, and to a lesser extent, our derivative counterparties. We monitor our exposure to these counterparties primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty's creditworthiness. Although we have not generally required our counterparties to provide collateral to support their obligations to us, we may, if circumstances dictate, require collateral in the future. In this manner, we could reduce credit risk. Under the terms of our credit facility, certain events could occur that would cause the obligations under our credit facility to no longer be secured by our oil and natural gas properties. In this circumstance, we have certain agreements in place with our derivative counterparties that would regulate collateral related to derivative transactions.

We have entered into International Swap Dealers Association Master Agreements ("ISDA Agreements") with each of our derivative counterparties. The terms of the ISDA Agreements provide us and the counterparties with rights of set-off upon the occurrence of defined acts of default by either us or a counterparty to a derivative, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party. See Note 8 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding our derivative activities.

Commodity price risk. We are exposed to market risk as the prices of our commodities are subject to fluctuations resulting from changes in supply and demand. To reduce our exposure to changes in the prices of our commodities, we have entered into, and may in the future enter into, additional commodity price risk management arrangements for a portion of our oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Our commodity price risk management arrangements are recorded at fair value and thus changes to the future commodity prices will have an impact on net income. The following table sets forth the hypothetical impact on the fair value of the commodity price risk management arrangements from an average increase and decrease in the commodity price of $5.00 per Bbl of oil and $0.50 per MMBtu of natural gas from the commodity prices at December 31, 2016:

(in thousands)	Increase of $5.00 per Bbl and $0.50 per MMBtu	Decrease of $5.00 per Bbl and $0.50 per MMBtu
Gain (loss):		
Oil derivatives	$ (216,120)	$ 216,120
Natural gas derivatives	(33,441)	33,441
Total	$ (249,561)	$ 249,561

Our commodity price risk management arrangements expose us to risk of non-performance by the counterparty to the agreements. Our exposure to the risk of non-performance is diversified over large, investment grade financial institutions. In addition, we have master netting agreements with the counterparties that allow for offsetting payables against receivables from separate contracts with the same counterparty. At December 31, 2016, the counterparties to our commodity price risk management arrangements include sixteen financial institutions, all of which are secured lenders to our credit facility. Risk of non-performance is considered when determining the fair value of our commodity price risk management arrangements. The fair value adjustment for non-performance risk was immaterial at December 31, 2016. If at any point a counterparty's financial position deteriorates, such deterioration could have a significant impact on the collectability of that counterparty's related commodity price risk management arrangement asset.

At December 31, 2016, we had (i) oil price swaps that settle on a monthly basis covering future oil production from January 1, 2017 through December 31, 2018 and (ii) oil basis swaps covering our Midland to Cushing basis differential from January 1, 2017 to December 31, 2018. See Note 8 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information on the commodity derivative instruments. The average NYMEX oil price for the year ended December 31, 2016, was $43.42 per Bbl. At February 17, 2017, the NYMEX oil price was $53.40 per Bbl.

At December 31, 2016, we had natural gas price swaps that settle on a monthly basis covering future natural gas production from January 1, 2017 to December 31, 2018. See Note 8 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information on our commodity derivative instruments. The average NYMEX natural gas price for the year ended December 31, 2016, was $2.56 per MMBtu. At February 17, 2017, the NYMEX natural gas price was $2.83 per MMBtu.

A decrease in the average forward NYMEX oil and natural gas prices below those at December 31, 2016 would decrease the fair value liability of our commodity derivative contracts from their recorded balance at December 31, 2016. Changes in the recorded fair value of our commodity derivative contracts are marked to market through earnings as gains or losses. The potential decrease in our fair value liability would be recorded in earnings as a gain. However, an increase in the average forward NYMEX oil and natural gas prices above those at December 31, 2016 would increase the fair value liability of our commodity derivative contracts from their recorded balance at December 31, 2016. The potential increase in our fair value liability would be recorded in earnings as a loss. We are currently unable to estimate the effects on the earnings of future periods resulting from changes in the market value of our commodity derivative contracts.

We recorded a loss on derivatives of $368.7 million for the year ended December 31, 2016, compared to a gain of $699.8 million for the year ended December 31, 2015. The largest factor in the change from 2015 to 2016 primarily related to the decline in commodity future price curves at the respective measurement and settlement periods.

The fair value of our derivative instruments is determined based on our valuation models. We did not change our valuation method during the year ended December 31, 2016. During the year ended December 31, 2016, we were party to commodity derivative instruments. See Note 8 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding our derivative instruments. The following table reconciles the changes that occurred in the fair values of our derivative instruments during the year ended December 31, 2016:

(in thousands)	**Commodity Derivative Instruments Net Assets (Liabilities) (a)**
Fair value of contracts outstanding at December 31, 2015	$ 819,536
Changes in fair values (b)	(368,684)
Contract maturities	(625,250)
Fair value of contracts outstanding at December 31, 2016	$ (174,398)

(a) Represents the fair values of open derivative contracts subject to market risk.
(b) At inception, new derivative contracts entered into by us have no intrinsic value.

Interest rate risk. Our exposure to changes in interest rates relates primarily to debt obligations. We manage our interest rate exposure by limiting our variable-rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. To reduce our exposure to changes in interest rates we may, in the future, enter into interest rate risk management arrangements for a portion of our outstanding debt. The agreements that we have entered into generally have the effect of providing us with a fixed interest rate for a portion of our variable rate debt. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

We are exposed to changes in interest rates as a result of our credit facility, and the terms of our credit facility require us to pay higher interest rate margins as we utilize a larger percentage of our borrowing base.

We had no indebtedness outstanding under our credit facility at December 31, 2016.

Item 8. Financial Statements and Supplementary Data

Our consolidated financial statements and supplementary data are included in this report beginning on page F-1.

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

We had no changes in, and no disagreements with, our accountants on accounting and financial disclosure.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective at December 31, 2016 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting. There have been no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter 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

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed under the supervision of the Company's Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with generally accepted accounting principles.

As of December 31, 2016, management assessed the effectiveness of the Company's internal control over financial reporting based on the criteria for effective internal control over financial reporting established in the 2013 "Internal Control - Integrated Framework," issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our assessment and those criteria, management determined that the Company maintained effective internal control over financial reporting at December 31, 2016.

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.

Grant Thornton LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this annual report on Form 10-K, has issued their report on the effectiveness of the Company's internal control over financial reporting at December 31, 2016. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting at December 31, 2016, is included in this Item under the heading "Report of Independent Registered Public Accounting Firm."

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Concho Resources Inc.

We have audited the internal control over financial reporting of Concho Resources Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2016, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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.

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 the 2013 *Internal Control—Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Company as of and for the year ended December 31, 2016, and our report dated February 22, 2017 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 22, 2017

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Item 10 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2016.

Item 11. Executive Compensation

Item 11 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2016.

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

Equity compensation plans. At December 31, 2016, a total of 10,500,000 shares of common stock were authorized for issuance under our equity compensation plan. In the table below, we describe certain information about these shares and the equity compensation plan which provides for their authorization and issuance. Included in column (1) are (a) unvested performance units at the maximum potential payout percentage and (b) performance units relating to the performance period that ended on December 31, 2016 at the actual payout percentage of 182.5 percent. You can find descriptions of our stock incentive plan under Note 6 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

Plan category	(1) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(2) Weighted average exercise price of outstanding options	(3) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (1))
Equity compensation plan approved by the security holders (a)	1,263,341	$ 15.33 (c)	2,383,534
Equity compensation plan not approved by the security holders (b)	-	$ -	-
Total	1,263,341		2,383,534

(a) 2015 Stock Incentive Plan. See Note 6 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

(b) None.

(c) Performance unit awards do not have an exercise price and, therefore, have been excluded from the weighted average exercise price calculation in column (2).

The remaining information required by Item 12 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2016.

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

Item 13 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2016.

Item 14. Principal Accounting Fees and Services

Item 14 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2016.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) Listing of Financial Statements

Financial Statements

The following consolidated financial statements are included in "Item 8. Financial Statements and Supplementary Data":

Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheets at December 31, 2016 and 2015

Consolidated Statements of Operations for the Years Ended December 31, 2016, 2015 and 2014

Consolidated Statements of Stockholders' Equity for the Years Ended December 31, 2016, 2015 and 2014

Consolidated Statements of Cash Flows for the Years Ended December 31, 2016, 2015 and 2014

Notes to Consolidated Financial Statements

Unaudited Supplementary Data

(b) Exhibits

The exhibits to this report required to be filed pursuant to Item 15(b) are listed below and in the "Index to Exhibits" attached hereto.

(c) Financial Statement Schedules

No financial statement schedules are required to be filed as part of this report or they are inapplicable.

Exhibits

Exhibit Number	Description
3.1	Restated Certificate of Incorporation of Concho Resources Inc. (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K on August 8, 2007, and incorporated herein by reference).
3.2	Second Amended and Restated Bylaws of Concho Resources Inc., as amended November 7, 2012 (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K on November 8, 2012, and incorporated herein by reference).
4.1	Specimen Common Stock Certificate (filed as Exhibit 4.1 to the Company's Annual Report on Form 10-K on February 22, 2013, and incorporated herein by reference).
4.2	Indenture, dated September 18, 2009, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on September 22, 2009, and incorporated herein by reference).

Exhibit Number		Description
4.3		Second Supplemental Indenture, dated November 3, 2010, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.4 to the Post-Effective Amendment to the Company's Registration Statement on Form S-3 on December 7, 2010, and incorporated herein by reference).
4.4		Fifth Supplemental Indenture, dated December 12, 2011, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.7 to the Company's Annual Report on Form 10-K on February 24, 2012, and incorporated herein by reference).
4.5		Sixth Supplemental Indenture, dated March 12, 2012, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on March 12, 2012, and incorporated herein by reference).
4.6		Seventh Supplemental Indenture, dated August 17, 2012, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on August 17, 2012, and incorporated herein by reference).
4.7		Tenth Supplemental Indenture, dated December 28, 2016, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on December 28, 2016, and incorporated herein by reference).
4.8		Form of 5.5% Senior Notes due 2022 (included in Exhibit 4.1 to the Company's Current Report on Form 8-K filed on March 12, 2012, and incorporated herein by reference).
4.9		Form of 5.5% Senior Notes due 2023 (included in Exhibit 4.1 to the Company's Current Report on Form 8-K filed on August 17, 2012, and incorporated herein by reference).
4.10		Form of 4.375% Senior Notes due 2025 (included in Exhibit 4.1 to the Company's Current Report on Form 8-K filed on December 28, 2016, and incorporated herein by reference).
10.1	**	Form of Performance Unit Award Agreement (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on January 4, 2013, and incorporated herein by reference).
10.2	**	Concho Resources Inc. 2015 Stock Incentive Plan (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on June 5, 2015, and incorporated herein by reference).
10.3	**	Form of Nonstatutory Stock Option Agreement (filed as Exhibit 10.16 to the Company's Annual Report on Form 10-K on March 28, 2008, and incorporated herein by reference).
10.4	**	Form of Restricted Stock Agreement (for officers) (filed as Exhibit 10.11 to the Company's Annual Report on Form 10-K on February 22, 2013, and incorporated herein by reference).
10.5	**	Form of Restricted Stock Agreement (for non-employee directors) (filed as Exhibit 10.18 to the Company's Annual Report on Form 10-K on March 28, 2008, and incorporated herein by reference).
10.6	**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Timothy A. Leach (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).

Exhibit Number		Description
10.7	**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and E. Joseph Wright (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).
10.8	**	Employment Agreement dated November 5, 2009, between Concho Resources Inc. and C. William Giraud (filed as Exhibit 10.18 to the Company's Annual Report on Form 10-K on February 26, 2010, and incorporated herein by reference).
10.9	**	Employment Agreement dated March 19, 2014, between Concho Resources Inc. and Jack F. Harper (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on March 24, 2014, and incorporated herein by reference).
10.10	**	Employment Agreement dated May 17, 2016, between Concho Resources Inc. and Darin G. Holderness (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on May 19, 2016, and incorporated herein by reference).
10.11	**	Form of First Amendment to Employment Agreement between Concho Resources Inc. and each of Messrs. Leach, Giraud and Wright (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q on May 6, 2011, and incorporated herein by reference).
10.12	**	Form of Indemnification Agreement between Concho Resources Inc. and each of the officers and directors thereof (filed as Exhibit 10.23 to the Company's Registration Statement on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.13	**	Indemnification Agreement, dated February 27, 2008, by and between Concho Resources, Inc. and William H. Easter III (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on March 4, 2008, and incorporated herein by reference).
10.14	**	Indemnification Agreement, dated May 21, 2008, by and between Concho Resources, Inc. and Matthew G. Hyde (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on May 28, 2008, and incorporated herein by reference).
10.15	**	Indemnification Agreement, dated August 25, 2008, by and between Concho Resources, Inc. and Darin G. Holderness (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on August 29, 2008, and incorporated herein by reference).
10.16	**	Indemnification Agreement, dated November 5, 2009, by and between Concho Resources, Inc. and Mark B. Puckett (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on November 12, 2009, and incorporated herein by reference).
10.17	**	Indemnification Agreement, dated November 5, 2009, by and between Concho Resources, Inc. and C. William Giraud (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on November 12, 2009, and incorporated herein by reference).
10.18	**	Form of Director and Officer Indemnification Agreement between Concho Resources Inc. and each of Messrs. Surma and Harper (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on March 24, 2014, and incorporated herein by reference).
10.19	**	Indemnification Agreement, dated January 10, 2012, between Concho Resources Inc. and Gary A. Merriman (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on January 12, 2012, and incorporated herein by reference).

Exhibit Number		Description
10.20		Second Amended and Restated Credit Agreement, dated as of May 9, 2014, among Concho Resources Inc., the lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q on May 12, 2014, and incorporated herein by reference).
10.21		First Amendment to Second Amended and Restated Credit Agreement, dated as of April 8, 2015, among Concho Resources Inc., the lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on April 9, 2015, and incorporated herein by reference).
10.22		Registration Rights Agreement, dated February 27, 2006, among Concho Resources Inc. and the other signatories thereto (filed as Exhibit 10.12 to the Company's Registration Statement on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.23		Purchase and Sale Agreement, dated August 15, 2016, by and among COG Operating LLC, as purchaser, Concho Resources Inc., as purchaser parent, and Reliance Energy Inc., Reliance Exploration, Ltd., Reliance Energy-WA, LLC, Reliance Energy-GF, LLC and the other persons named as sellers therein, as sellers (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K on August 16, 2016, and incorporated herein by reference).
12.1	(a)	Ratio of Earnings to Fixed Charges and Ratio of Earnings to Fixed Charges and Preferred Stock Dividends.
21.1	(a)	Subsidiaries of Concho Resources Inc.
23.1	(a)	Consent of Grant Thornton LLP.
23.2	(a)	Consent of Netherland, Sewell & Associates, Inc.
23.3	(a)	Consent of Cawley, Gillespie & Associates, Inc.
31.1	(a)	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	(a)	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	(b)	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	(b)	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	(a)	Netherland, Sewell & Associates, Inc. Reserve Report.
99.2	(a)	Cawley, Gillespie & Associates, Inc. Reserve Report.
101.INS	(a)	XBRL Instance Document.
101.SCH	(a)	XBRL Schema Document.
101.CAL	(a)	XBRL Calculation Linkbase Document.
101.DEF	(a)	XBRL Definition Linkbase Document.
101.LAB	(a)	XBRL Labels Linkbase Document.
101.PRE	(a)	XBRL Presentation Linkbase Document.

Exhibit Number	Description

(a) Filed herewith.
(b) Furnished herewith.
** Management contract or compensatory plan or agreement

GLOSSARY OF TERMS

The following terms are used throughout this report:

Bbl	One stock tank barrel, of 42 United States gallons liquid volume, used herein in reference to oil, condensate or natural gas liquids.
Boe	One barrel of oil equivalent, a standard convention used to express oil and natural gas volumes on a comparable oil equivalent basis. Natural gas equivalents are determined under the relative energy content method by using the ratio of 6.0 Mcf of natural gas to 1.0 Bbl of oil or condensate.
Basin	A large natural depression on the earth's surface in which sediments accumulate.
Development wells	Wells drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.
Dry hole	A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed production expenses, taxes and the royalty burden.
Exploratory wells	Wells drilled to find and produce oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir, or to extend a known reservoir.
Field	An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.
GAAP	Generally accepted accounting principles in the United States of America.
Gross wells	The number of wells in which a working interest is owned.
Horizontal drilling	A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a high angle to vertical (which can be greater than 90 degrees) in order to stay within a specified interval.
Infill drilling	Drilling into the same pool as known producing wells so that oil or natural gas does not have to travel as far through the formation.
LIBOR	London Interbank Offered Rate, which is a market rate of interest.
MBbl	One thousand barrels of oil, condensate or natural gas liquids.
MBoe	One thousand Boe.
Mcf	One thousand cubic feet of natural gas.
MMBoe	One million Boe.
MMBtu	One million British thermal units.
MMcf	One million cubic feet of natural gas.

NYMEX The New York Mercantile Exchange.

NYSE The New York Stock Exchange.

Net acres The percentage of total acres an owner owns out of a particular number of acres within a specified tract. For example, an owner who has a 50 percent interest in 100 acres owns 50 net acres.

Net wells The total of fractional working interests owned in gross wells.

Productive wells Wells that produce commercial quantities of hydrocarbons, exclusive of their capacity to produce at a reasonable rate of return.

Proved developed reserves Proved developed reserves are proved reserves that can be expected to be recovered:

(i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) through installed extraction equipment and infrastructure operational at the time of the reserve estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Proved Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Proved Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

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

(i) The area of the reservoir considered as proved includes:

(A) the area identified by drilling and limited by fluid contacts, if any, and

(B) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons ("LKH") as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

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

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) the project has been approved for development by all necessary parties and entities, including governmental entities.

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

Proved undeveloped reserves Proved undeveloped oil and natural gas reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

Recompletion The addition of production from another interval or formation in an existing wellbore.

Reservoir A formation beneath the surface of the earth from which hydrocarbons may be present. Its make-up is sufficiently homogenous to differentiate it from other formations.

Spacing The distance between wells producing from the same reservoir. Spacing is expressed in terms of acres, e.g., 40-acre spacing, and is established by regulatory agencies.

Standardized Measure The present value (discounted at an annual rate of 10 percent) of estimated future net revenues to be generated from the production of proved reserves net of estimated income taxes associated with such net revenues, as determined in accordance with FASB guidelines, without giving effect to non-property related expenses such as indirect general and administrative expenses, and debt service or to depreciation, depletion and amortization. Standardized measure does not give effect to derivative transactions.

Undeveloped acreage	Acreage owned or leased on which wells can be drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.
Wellbore	The hole drilled by the bit that is equipped for oil or natural gas production on a completed well. Also called a well or borehole.
Working interest	The right granted to the lessee of a property to explore for and to produce and own oil, natural gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.
Workover	Operations on a producing well to restore or increase production.
WTI	West Texas Intermediate - light, sweet blend of oil produced from fields in western Texas.

SIGNATURES

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

CONCHO RESOURCES INC.

Date: February 22, 2017

By /s/ Timothy A. Leach

Timothy A. Leach
Director, Chairman of the Board of Directors, Chief Executive Officer and President (Principal Executive Officer)

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

Signature	Title	Date
/s/ TIMOTHY A. LEACH Timothy A. Leach	Director, Chairman of the Board of Directors, Chief Executive Officer and President (Principal Executive Officer)	February 22, 2017
/s/ JACK F. HARPER Jack F. Harper	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 22, 2017
/s/ BRENDA R. SCHROER Brenda R. Schroer	Vice President, Chief Accounting Officer and Treasurer (Principal Accounting Officer)	February 22, 2017
/s/ STEVEN L. BEAL Steven L. Beal	Director	February 22, 2017
/s/ TUCKER S. BRIDWELL Tucker S. Bridwell	Director	February 22, 2017
/s/ WILLIAM H. EASTER III William H. Easter III	Director	February 22, 2017
/s/ GARY A. MERRIMAN Gary A. Merriman	Director	February 22, 2017
/s/ RAY M. POAGE Ray M. Poage	Director	February 22, 2017
/s/ MARK B. PUCKETT Mark B. Puckett	Director	February 22, 2017
/s/ JOHN P. SURMA John P. Surma	Director	February 22, 2017

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Financial Statements of Concho Resources Inc.:

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Concho Resources Inc.

We have audited the accompanying consolidated balance sheets of Concho Resources Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Concho Resources Inc. and subsidiaries as of 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.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2016, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 22, 2017 expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 22, 2017

Concho Resources Inc.
Consolidated Balance Sheets

(in thousands, except share and per share amounts)	December 31, 2016	December 31, 2015
Assets		
Current assets:		
Cash and cash equivalents	$ 53,261	$ 228,550
Accounts receivable, net of allowance for doubtful accounts:		
Oil and natural gas	220,152	203,972
Joint operations and other	238,217	190,608
Derivative instruments	3,551	652,498
Prepaid costs and other	31,313	38,922
Total current assets	546,494	1,314,550
Property and equipment:		
Oil and natural gas properties, successful efforts method	18,476,279	15,846,307
Accumulated depletion and depreciation	(7,389,844)	(5,047,810)
Total oil and natural gas properties, net	11,086,435	10,798,497
Other property and equipment, net	215,998	178,450
Total property and equipment, net	11,302,433	10,976,947
Funds held in escrow	43,000	-
Deferred loan costs, net	10,909	15,585
Intangible asset - operating rights, net	24,232	25,693
Inventory	16,303	19,118
Noncurrent derivative instruments	-	167,038
Other assets	175,955	122,945
Total assets	$ 12,119,326	$ 12,641,876
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable - trade	$ 28,450	$ 13,200
Revenue payable	131,592	169,787
Accrued and prepaid drilling costs	359,495	228,523
Derivative instruments	82,079	-
Other current liabilities	151,570	184,910
Total current liabilities	753,186	596,420
Long-term debt	2,740,580	3,332,188
Deferred income taxes	766,032	1,630,373
Noncurrent derivative instruments	95,870	-
Asset retirement obligations and other long-term liabilities	140,965	140,344
Commitments and contingencies (Note 10)		
Stockholders' equity:		
Common stock, $0.001 par value; 300,000,000 authorized; 146,488,685 and 129,444,042 shares issued at December 31, 2016 and 2015, respectively	146	129
Additional paid-in capital	6,782,914	4,628,390
Retained earnings	883,195	2,345,641
Treasury stock, at cost; 429,708 and 306,061 shares at December 31, 2016 and 2015, respectively	(43,562)	(31,609)
Total stockholders' equity	7,622,693	6,942,551
Total liabilities and stockholders' equity	$ 12,119,326	$ 12,641,876

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

Concho Resources Inc.
Consolidated Statements of Operations

(in thousands, except per share amounts)	Years Ended December 31, 2016	2015	2014
Operating revenues:			
Oil sales	$ 1,350,367	$ 1,539,917	$ 2,189,072
Natural gas sales	284,621	263,656	471,075
Total operating revenues	1,634,988	1,803,573	2,660,147
Operating costs and expenses:			
Oil and natural gas production	451,304	541,359	538,374
Exploration and abandonments	77,454	58,847	284,821
Depreciation, depletion and amortization	1,167,208	1,223,253	979,740
Accretion of discount on asset retirement obligations	7,133	7,600	7,072
Impairments of long-lived assets	1,524,645	60,529	447,151
General and administrative (including non-cash stock-based compensation of $58,927, $63,073 and $47,130 for the years ended December 31, 2016, 2015 and 2014, respectively)	225,565	230,734	204,161
(Gain) loss on derivatives	368,684	(699,752)	(890,917)
(Gain) loss on disposition of assets, net	(117,561)	53,789	9,308
Total operating costs and expenses	3,704,432	1,476,359	1,579,710
Income (loss) from operations	(2,069,444)	327,214	1,080,437
Other income (expense):			
Interest expense	(203,518)	(215,384)	(216,661)
Loss on extinguishment of debt	(56,436)	-	(4,316)
Other, net	(9,138)	(14,559)	(3,500)
Total other expense	(269,092)	(229,943)	(224,477)
Income (loss) before income taxes	(2,338,536)	97,271	855,960
Income tax (expense) benefit	876,090	(31,371)	(317,785)
Net income (loss)	$ (1,462,446)	$ 65,900	$ 538,175
Earnings per share:			
Basic net income (loss)	$ (10.85)	$ 0.54	$ 4.89
Diluted net income (loss)	$ (10.85)	$ 0.54	$ 4.88

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

Concho Resources Inc.
Consolidated Statements of Stockholders' Equity

(in thousands)	Common Stock Issued		Additional Paid-in Capital	Retained Earnings	Treasury Stock		Total Stockholders' Equity
	Shares	Amount			Shares	Amount	
BALANCE AT JANUARY 1, 2014	105,223	$ 105	$ 2,027,162	$ 1,741,566	127	$ (10,884)	$ 3,757,949
Net income	-	-	-	538,175	-	-	538,175
Issuance of common stock	7,475	7	931,982	-	-	-	931,989
Stock options exercised	208	1	4,658	-	-	-	4,659
Grants of restricted stock	448	-	-	-	-	-	-
Cancellation of restricted stock	(89)	-	-	-	-	-	-
Stock-based compensation	-	-	47,130	-	-	-	47,130
Excess tax benefits related to stock-based compensation	-	-	16,480	-	-	-	16,480
Purchase of treasury stock	-	-	-	-	133	(15,594)	(15,594)
BALANCE AT DECEMBER 31, 2014	113,265	113	3,027,412	2,279,741	260	(26,478)	5,280,788
Net income	-	-	-	65,900	-	-	65,900
Issuance of common stock	15,755	16	1,535,696	-	-	-	1,535,712
Stock options exercised	5	-	59	-	-	-	59
Grants of restricted stock	452	-	-	-	-	-	-
Cancellation of restricted stock	(33)	-	-	-	-	-	-
Stock-based compensation	-	-	63,073	-	-	-	63,073
Excess tax benefits related to stock-based compensation	-	-	2,150	-	-	-	2,150
Purchase of treasury stock	-	-	-	-	46	(5,131)	(5,131)
BALANCE AT DECEMBER 31, 2015	129,444	129	4,628,390	2,345,641	306	(31,609)	6,942,551
Net loss	-	-	-	(1,462,446)	-	-	(1,462,446)
Issuance of common stock	10,350	10	1,327,434	-	-	-	1,327,444
Common stock issued in business combinations	6,134	6	768,362	-	-	-	768,368
Stock options exercised	23	1	470	-	-	-	471
Grants of restricted stock	451	-	-	-	-	-	-
Performance unit share conversion	180	-	-	-	-	-	-
Cancellation of restricted stock	(93)	-	-	-	-	-	-
Stock-based compensation	-	-	58,927	-	-	-	58,927
Tax deficiency related to stock-based compensation	-	-	(669)	-	-	-	(669)
Purchase of treasury stock	-	-	-	-	124	(11,953)	(11,953)
BALANCE AT DECEMBER 31, 2016	146,489	$ 146	$ 6,782,914	$ 883,195	430	$ (43,562)	$ 7,622,693

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

Concho Resources Inc.
Consolidated Statements of Cash Flows

(in thousands)	Years Ended December 31, 2016	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (1,462,446)	$ 65,900	$ 538,175
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	1,167,208	1,223,253	979,740
Accretion of discount on asset retirement obligations	7,133	7,600	7,072
Impairments of long-lived assets	1,524,645	60,529	447,151
Exploration and abandonments, including dry holes	66,621	43,737	265,064
Non-cash stock-based compensation expense	58,927	63,073	47,130
Deferred income taxes	(864,341)	29,622	296,167
(Gain) loss on disposition of assets, net	(117,561)	53,789	9,308
(Gain) loss on derivatives	368,684	(699,752)	(890,917)
Net settlements received from derivatives	625,250	632,916	71,983
Loss on extinguishment of debt	56,436	-	4,316
Other non-cash items	13,942	14,639	14,063
Changes in operating assets and liabilities, net of acquisitions and dispositions:			
Accounts receivable	21,958	117,716	(104,988)
Prepaid costs and other	6,063	(3,726)	(23,628)
Inventory	1,891	(5,154)	2,441
Accounts payable	15,246	(17,689)	1,566
Revenue payable	(37,588)	(68,311)	60,481
Other current liabilities	(67,620)	12,279	20,646
Net cash provided by operating activities	1,384,448	1,530,421	1,745,770
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures on oil and natural gas properties	(2,397,217)	(2,443,704)	(2,554,914)
Additions to property, equipment and other assets	(60,655)	(67,699)	(34,320)
Proceeds from the disposition of assets	331,966	104	1,305
Funds held in escrow	(43,000)	-	-
Contributions to equity method investments	(55,750)	(91,342)	(30,050)
Net cash used in investing activities	(2,224,656)	(2,602,641)	(2,617,979)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from issuance of debt	600,000	1,490,900	2,081,000
Payments of debt	(1,200,000)	(1,630,400)	(2,191,500)
Debt extinguishment costs	(42,450)	-	-
Exercise of stock options	471	59	4,659
Excess tax benefit (deficiency) from stock-based compensation	(669)	2,150	16,480
Net proceeds from issuance of common stock	1,327,444	1,535,712	931,989
Payments for loan costs	(7,924)	-	(10,648)
Purchase of treasury stock	(11,953)	(5,131)	(15,594)
Increase (decrease) in bank overdrafts	-	(92,541)	55,823
Net cash provided by financing activities	664,919	1,300,749	872,209
Net increase (decrease) in cash and cash equivalents	(175,289)	228,529	-
Cash and cash equivalents at beginning of period	228,550	21	21
Cash and cash equivalents at end of period	$ 53,261	$ 228,550	$ 21
SUPPLEMENTAL CASH FLOWS:			
Cash paid for interest	$ 232,173	$ 211,443	$ 211,342
Cash paid for income taxes	$ -	$ 3,950	$ 27,844
NON-CASH INVESTING AND FINANCING ACTIVITIES:			
Issuance of common stock for business combinations	$ 768,368	$ -	$ -

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

Concho Resources Inc.
Notes to Consolidated Financial Statements
December 31, 2016, 2015 and 2014

Note 1. ***Organization and nature of operations***

Concho Resources Inc. (the "Company") is a Delaware corporation formed on February 22, 2006. The Company's principal business is the acquisition, development, exploration and production of oil and natural gas properties primarily located in the Permian Basin of Southeast New Mexico and West Texas.

Note 2. ***Summary of significant accounting policies***

Principles of consolidation. The consolidated financial statements of the Company include the accounts of the Company and its 100 percent owned subsidiaries. The Company consolidates the financial statements of these entities. All material intercompany balances and transactions have been eliminated.

Reclassifications. Certain prior period amounts have been reclassified to conform to the 2016 presentation. These reclassifications had no impact on net income (loss), total stockholders' equity or total cash flows.

Use of estimates in the preparation of financial statements. Preparation of financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from these estimates. Depletion of oil and natural gas properties is determined using estimates of proved oil and natural gas reserves. There are numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. Similarly, evaluations for impairment of proved and unproved oil and natural gas properties are subject to numerous uncertainties including, among others, estimates of future recoverable reserves, commodity price outlooks and prevailing market rates of other sources of income and costs. Other significant estimates include, but are not limited to, asset retirement obligations, fair value of stock-based compensation, fair value of business combinations, fair value of nonmonetary exchanges, fair value of derivative financial instruments and income taxes.

Cash equivalents. The Company considers all cash on hand, depository accounts held by banks, money market accounts and investments with an original maturity of three months or less to be cash equivalents. The Company's cash and cash equivalents are held in financial institutions in amounts that exceed the insurance limits of the Federal Deposit Insurance Corporation. However, management believes that the Company's counterparty risks are minimal based on the reputation and history of the institutions selected.

Accounts receivable. The Company sells oil and natural gas to various customers and participates with other parties in the drilling, completion and operation of oil and natural gas wells. Joint interest and oil and natural gas sales receivables related to these operations are generally unsecured. The Company determines joint interest operations accounts receivable allowances based on management's assessment of the creditworthiness of the joint interest owners and the Company's ability to realize the receivables through netting of anticipated future production revenues. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been exhausted. The Company had an allowance for doubtful accounts of approximately $1.2 million for each of the years ended December 31, 2016 and 2015.

Oil and natural gas properties. The Company utilizes the successful efforts method of accounting for its oil and natural gas properties. Under this method all costs associated with productive wells and nonproductive development wells are capitalized, while nonproductive exploration costs are expensed. Capitalized acquisition costs relating to proved properties are depleted using the unit-of-production method based on proved reserves. The depletion of capitalized drilling and development costs and integrated assets is based on the unit-of-production method using proved developed reserves. During the years ended December 31, 2016, 2015 and 2014, the Company recognized depletion expense from operations of $1,145.2 million, $1,203.5 million and $960.9 million, respectively.

The Company generally does not carry the costs of drilling an exploratory well as an asset in its consolidated balance sheets following the completion of drilling unless both of the following conditions are met:

(i) the well has found a sufficient quantity of reserves to justify its completion as a producing well; and

(ii) the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

Due to the capital intensive nature and the geographical location of certain projects, it may take the Company longer than one year to evaluate the future potential of the exploration well and economics associated with making a determination on its commercial viability. In these instances, the project's feasibility is not contingent upon price improvements or advances in technology, but rather the Company's ongoing efforts and expenditures related to accurately predicting the hydrocarbon recoverability based on well information, gaining access to other companies' production, transportation or processing facilities and/or getting partner approval to drill additional appraisal wells. These activities are ongoing and being pursued constantly. Consequently, the Company's assessment of suspended exploratory well costs is continuous until a decision can be made that the well has found proved reserves or is noncommercial and is charged to exploration and abandonments expense. See Note 3 for additional information regarding the Company's suspended exploratory well costs.

Proceeds from the sales of individual properties and the capitalized costs of individual properties sold or abandoned are credited and charged, respectively, to accumulated depletion. Generally, no gain or loss is recognized until the entire depletion base is sold. However, gain or loss is recognized from the sale of less than an entire depletion base if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the depletion base. Ordinary maintenance and repair costs are expensed as incurred.

Costs of significant nonproducing properties, wells in the process of being drilled and completed and development projects are excluded from depletion until the related project is completed and proved developed reserves are established or, if unsuccessful, impairment is determined. The Company capitalizes interest, if debt is outstanding, on expenditures for significant development projects until such projects are ready for their intended use. The Company did not have capitalized interest related to significant oil and natural gas development projects for the year ended December 31, 2016. During the years ended December 31, 2015 and 2014, the Company had capitalized interest of $0.7 million and $1.4 million, respectively.

The Company reviews its long-lived assets to be held and used, including proved oil and natural gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss is indicated if the sum of the expected future cash flows is less than the carrying amount of the assets. In this circumstance, the Company recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset. The Company reviews its oil and natural gas properties by depletion base or by individual well for those wells not constituting part of a depletion base. For each property determined to be impaired, an impairment loss equal to the difference between the carrying value of the properties and the estimated fair value (discounted future cash flows) of the properties and integrated assets would be recognized at that time. Estimating future cash flows involves the use of judgments, including estimation of the proved and risk-adjusted unproved oil and natural gas reserve quantities, timing of development and production, expected future commodity prices, capital expenditures and production costs and cash flows from integrated assets. The Company recognized impairment expense of $1,524.6 million, $60.5 million and $447.2 million during the years ended December 31, 2016, 2015 and 2014, respectively, related to its proved oil and natural gas properties. See Note 7 for additional information regarding the Company's impairment expense.

Unproved oil and natural gas properties are periodically assessed for impairment by considering future drilling and exploration plans, results of exploration activities, commodity price outlooks, planned future sales and expiration of all or a portion of the projects. During the years ended December 31, 2016, 2015 and 2014, the Company recognized expense of $59.8 million, $34.5 million and $217.3 million, respectively, related to abandoned prospects, expiring acreage and abandoned well costs, which is included in exploration and abandonments expense in the accompanying consolidated statements of operations.

Other property and equipment. Other capital assets include buildings, transportation equipment, computer equipment and software, telecommunications equipment, leasehold improvements and furniture and fixtures. These items are recorded at cost, or fair value if acquired, and are depreciated using the straight-line method based on expected lives of the individual assets or group of assets ranging from two to 39 years. The Company had other capital assets of $216.0 million and $178.5 million, net of accumulated depreciation of $73.7 million and $54.4 million, at December 31, 2016 and December 31, 2015, respectively. During the years ended December 31, 2016, 2015 and 2014, the Company recognized depreciation expense of $20.6 million, $18.3 million and $17.3 million, respectively. Additionally, during the year ended December 31, 2016, the Company had capitalized interest of $0.3 million related to other property and equipment.

Funds held in escrow. At December 31, 2016, the Company's funds held in escrow totaled $43.0 million, which consists of a deposit paid by the Company that was held in escrow for the Northern Delaware Basin acquisition that partially closed in January 2017. See Note 17 for additional information regarding the acquisition.

Deferred loan costs. Deferred loan costs are stated at cost, net of amortization, which is computed using the straight-line method. The Company had deferred loan costs related to its credit facility of $10.9 million and $15.6 million, net of accumulated amortization of $55.7 million and $51.0 million, in noncurrent assets at December 31, 2016 and 2015, respectively.

Intangible assets. The Company has capitalized certain operating rights acquired in an acquisition. The gross operating rights, which have no residual value, are amortized over the estimated economic life of 25 years. Impairment will be assessed if indicators of potential impairment exist or when there is a material change in the remaining useful economic life. The following table reflects the gross and net intangible assets at December 31, 2016 and 2015, respectively:

	December 31,	
(in thousands)	**2016**	**2015**
Gross intangible - operating rights	$ 36,557	$ 36,557
Accumulated amortization	(12,325)	(10,864)
Net intangible - operating rights	$ 24,232	$ 25,693

The following table reflects amortization expense from operations for the years ended December 31, 2016, 2015 and 2014:

	Years Ending December 31,		
(in thousands)	**2016**	**2015**	**2014**
Amortization expense	$ 1,461	$ 1,461	$ 1,461

The following table reflects the estimated aggregate amortization expense for each of the periods presented below at December 31, 2016:

(in thousands)	
2017	$ 1,461
2018	1,461
2019	1,461
2020	1,461
2021	1,461
Thereafter	16,927
Total	$ 24,232

Inventory. Inventory consists primarily of tubular goods, water and other oilfield equipment that the Company plans to utilize in its ongoing exploration and development activities and is carried at the lower of cost or market value, on a weighted average cost basis.

Equity method investments. At December 31, 2016, the Company owned a 50 percent membership interest in a midstream joint venture, Alpha Crude Connector, LLC ("ACC"), that constructed a crude oil gathering and transportation system in the northern Delaware Basin. ACC commenced partial operations in late 2015 and completed construction of the pipeline in April 2016. The Company has the option to purchase the membership interest of the other investor in ACC. This purchase option became exercisable in July 2016 and will expire after one year. During January 2017, the Company and its joint venture partner entered into separate agreements to sell 100 percent of their respective ownership interests in ACC. See Note 17 for additional information regarding the disposition of ACC.

The Company accounts for its investment in ACC under the equity method of accounting for investments in unconsolidated affiliates. The Company's net investment in ACC was approximately $128.7 million and $98.9 million at December 31, 2016 and 2015, respectively, and is included in other assets in the Company's consolidated balance sheets. The equity loss for the years ended December 31, 2016, 2015 and 2014 was approximately $2.1 million, $4.1 million and $1.3 million, respectively, and is included in other expense in the Company's consolidated statements of operations. During the year ended 2016, the Company did not capitalize any interest on its investment in ACC. During the years ended 2015 and 2014, the Company recorded approximately $2.9 million and $0.7 million, respectively, of capitalized interest on its investment in ACC.

During the year ended 2015, the Company purchased a 25 percent membership interest in an entity constructing a crude oil gathering and transportation system in the southern Delaware Basin. The initial system is operational and was substantially completed during 2016. The Company accounts for its investment under the equity method of accounting for investments in unconsolidated affiliates. The Company's net investment was approximately $42.5 million and $20.8 million at December 31, 2016 and 2015, respectively, and is included in other assets in the Company's consolidated balance sheets. The equity loss for the year ended December 31, 2016 was approximately $2.1 million, and is included in other expense in the Company's consolidated statements of operations.

Environmental. The Company is subject to extensive federal, state and local environmental laws and regulations. These laws, which are often changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a noncapital nature are recorded when environmental assessment and/or remediation is probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. At December 31, 2016 and 2015, the Company has accrued approximately $1.4 million and $1.0 million, respectively, related to environmental liabilities. During the years ended December 31, 2016, 2015 and 2014, the Company recognized environmental charges of approximately $7.0 million, $2.7 million and $4.0 million, respectively.

Senior note deferred loan costs. Deferred loan costs are stated at cost, net of amortization, which is computed using the effective interest method. The Company had deferred loan costs related to its senior notes of $31.6 million and $42.9 million, net of accumulated amortization of $12.1 million and $18.7 million, as a reduction of long-term debt at December 31, 2016 and 2015, respectively. See Note 9 for additional information regarding 2016 activity related to the Company's senior notes.

Income taxes. The Company recognizes deferred tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

The Company evaluates uncertain tax positions for recognition and measurement in the consolidated financial statements. To recognize a tax position, the Company determines whether it is more likely than not that the tax positions will be sustained upon examination, including resolution of any related appeals or litigation, based on the technical merits of the position. A tax position that meets the more likely than not threshold is measured to determine the amount of benefit to be recognized in the consolidated financial statements. The amount of tax benefit recognized with respect to any tax position is measured as the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement. The Company had no material uncertain tax positions that required recognition in the consolidated financial statements at December 31, 2016 and 2015. Any interest or penalties would be recognized as a component of income tax expense.

Derivative instruments. The Company recognizes its derivative instruments, other than any commodity derivative contracts that are designated as normal purchase and normal sale, as either assets or liabilities measured at fair value. The Company netted the fair value of derivative instruments by counterparty in the accompanying consolidated balance sheets where the right of offset exists. The Company does not have any derivatives designated as fair value or cash flow hedges. The Company may also enter into physical delivery contracts to effectively provide commodity price hedges. Because these contracts are not expected to be net cash settled, they are considered to be normal sales contracts and not derivatives. Therefore, these contracts are not recorded in the Company's consolidated financial statements.

Asset retirement obligations. The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement cost included in the carrying amount of the related asset is allocated to expense through depletion of the asset. Changes in the liability due to passage of time are generally recognized as an increase in the carrying amount of the liability and as corresponding accretion expense. Based on certain factors including commodity prices and costs, the Company may revise its previous estimates related to the liability, which would also increase or decrease the associated oil and natural gas property asset.

Treasury stock. Treasury stock purchases are recorded at cost.

Revenue recognition. Oil and natural gas revenues are recorded at the time of physical transfer of such products to the purchaser, which for the Company is primarily at the wellhead. The Company follows the sales method of accounting for oil and natural gas sales, recognizing revenues based on the Company's actual proceeds from the oil and natural gas sold to purchasers.

Oil and natural gas imbalances. Oil and natural gas imbalances are generated on properties for which two or more owners have the right to take production "in-kind" and, in doing so, take more or less than their respective entitled percentage. Imbalances are tracked by well, but the Company does not record any receivable from or payable to the other owners unless the imbalance has reached a level at which it exceeds the remaining reserves in the respective well. If reserves are insufficient to offset the imbalance and the Company is in an overtake position, a liability is recorded for the amount of shortfall in reserves valued at a contract price or the market price in effect at the time the imbalance is generated. If the Company is in an undertake position, a receivable is recorded for an amount that is reasonably expected to be received, not to exceed the current market value of such imbalance. The Company had no significant imbalances at December 31, 2016 or 2015.

General and administrative expense. The Company receives fees for the operation of jointly-owned oil and natural gas properties during the drilling and production phases and records such reimbursements as reductions of general and administrative expense. Such fees totaled approximately $16.9 million, $19.2 million and $18.9 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Stock-based compensation. Stock-based compensation expense is recognized in the Company's financial statements on an accelerated basis over the awards' vesting periods based on their fair values on the dates of grant, net of an estimate for forfeitures. Stock-based compensation awards generally vest over a period ranging from one to eight years. The Company utilizes (i) the Black-Scholes option pricing model to measure the fair value of stock options, (ii) the average of the grant date's high and low stock prices for the fair value of restricted stock and (iii) the Monte Carlo simulation method for the fair value of performance unit awards.

Recent accounting pronouncements. In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)," which outlines a new, single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized. The new model will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services.

In August 2015, the FASB issued ASU No. 2015-14, "Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date," which deferred the effective date of ASU 2014-09 by one year. That new standard is now effective for annual reporting periods beginning after December 15, 2017. The Company expects to use the modified retrospective method to adopt the standard, meaning the cumulative effect of initially applying the standard will be recognized in the most current period presented in the financial statements. The Company is substantially complete with its internal evaluation of the adoption of this standard and does not expect this new guidance will have a material impact on its consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02, "Leases (Topic 842)," which supersedes current lease guidance. The new lease standard requires all leases with a term greater than one year to be recognized on the balance sheet while maintaining substantially similar classifications for finance and operating leases. Lease expense recognition on the income statement will be effectively unchanged. This guidance is effective for reporting periods beginning after December 15, 2018 and early adoption is permitted. The Company does not plan to early adopt the standard. The Company enters into lease agreements to support its operations. These agreements are for leases on assets such as office space, vehicles, field services and well equipment and drilling rigs. The Company is currently in the process of reviewing all contracts that could be applicable to this new guidance. The Company believes this new guidance will have a moderate impact to its consolidated balance sheet due to the recognition of lease-related assets and liabilities that were not previously recognized.

In March 2016, the FASB issued ASU No. 2016-09, "Compensation–Stock Compensations (Topic 718): Improvements to Employee Share-based Payment Accounting," which changes the accounting and presentation for share-based payment arrangements in the following areas: (i) recognition in the statement of operations of excess tax benefits and deficiencies; (ii) cash flow presentation of excess tax benefits and deficiencies; (iii) minimum statutory withholding thresholds and the classification on the cash flow statement of the withheld amounts; and (iv) an accounting policy election to recognize forfeitures as they occur. This guidance is effective for reporting periods beginning after December 15, 2016 and early adoption is permitted.

The Company will adopt ASU No. 2016-09 during the first quarter of 2017. The adoption will not have a material impact on prior period consolidated financial statements. The Company will elect to account for forfeitures of share-based payments as they occur. As of December 31, 2016, the Company had not recorded compensation expense of approximately \$8.2 million for its forfeiture estimate. The Company will prospectively classify excess tax benefits and deficiencies as operating activities on the consolidated statement of cash flows and will prospectively record as a discrete item in the income tax provision in the consolidated income statement. The Company will also recognize all excess tax benefits not previously realized, which totaled approximately \$4.7 million as of December 31, 2016. Upon adoption, the Company will record a cumulative-effect adjustment, which will decrease retained earnings by approximately \$0.5 million, increase additional paid-in capital by approximately \$8.2 million, and decrease net deferred income taxes by approximately \$7.7 million.

In June 2016, the FASB issued ASU No. 2016-13, "Financial Instruments–Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments," which replaces the current "incurred loss" methodology for recognizing credit losses with an "expected loss" methodology. This new methodology requires that a financial asset measured at amortized cost be presented at the net amount expected to be collected. This standard is intended to provide more timely decision-useful information about the expected credit losses on financial instruments. This guidance is effective for fiscal years beginning after December 15, 2019, and early adoption is allowed as early as fiscal years beginning after December 15, 2018. The Company does not believe this new guidance will have a material impact on its consolidated financial statements.

Note 3. ***Exploratory well costs***

The Company capitalizes exploratory well costs until a determination is made that the well has either found proved reserves or that it is impaired. The capitalized exploratory well costs are carried in unproved oil and natural gas properties. See Unaudited Supplementary Data for the proved and unproved components of oil and natural gas properties. If the exploratory well is determined to be impaired, the well costs are charged to exploration and abandonments expense in the consolidated statements of operations.

The following table reflects the Company's net capitalized exploratory well activity during each of the years ended December 31, 2016, 2015 and 2014:

	Years Ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Beginning capitalized exploratory well costs	$ 116,198	$ 241,657	$ 144,504
Additions to exploratory well costs pending the determination of proved reserves	143,981	102,846	234,057
Reclassifications due to determination of proved reserves	(85,985)	(227,746)	(99,657)
Exploratory well costs charged to expense	(5,707)	(559)	(37,247)
Disposition of wells	(17,339)	-	-
Ending capitalized exploratory well costs	$ 151,148	$ 116,198	$ 241,657

The following table provides an aging at December 31, 2016 and 2015 of capitalized exploratory well costs based on the date drilling was completed:

	December 31,	
(dollars in thousands)	**2016**	**2015**
Capitalized exploratory well costs that have been capitalized for a period of one year or less	$ 141,595	$ 98,764
Capitalized exploratory well costs that have been capitalized for a period greater than one year	9,553	17,434
Total capitalized exploratory well costs	$ 151,148	$ 116,198
Number of projects with exploratory well costs that have been capitalized for a period greater than one year	8	8

Northern Delaware Basin project. At December 31, 2016, the Company had approximately $4.9 million of suspended well costs greater than one year recorded for a well drilled in the third quarter of 2015. The Company expects to complete this well in the first quarter of 2017.

Midland Basin project. At December 31, 2016, the Company had approximately $1.7 million of suspended well costs greater than one year recorded for a well drilled in the third quarter of 2015. The Company expects to complete this well in 2017.

Projects operated by others. At December 31, 2016, the Company had approximately $3.0 million of suspended well costs greater than one year recorded for six wells that are operated by others and waiting on completion. Two of these wells completed drilling in 2014 and the remaining four wells completed drilling in 2015.

Note 4. ***Acquisitions and divestitures***

Reliance acquisition. In October 2016, the Company completed an acquisition of approximately 40,000 net acres in the northern Midland Basin and other assets from Reliance Energy, Inc. (collectively, the "Reliance Acquisition") for approximately $1.7 billion. As consideration for the acquisition, the Company paid approximately $1.2 billion in cash and issued to the seller approximately 3.9 million shares of common stock with an approximate value of $0.5 billion.

Approximately $29.2 million of operating revenues and approximately $9.6 million of income from operations attributed to the Reliance Acquisition are included in the Company's results of operations since the closing date in October 2016.

The following table reflects the fair value of the acquired assets and liabilities associated with the Reliance Acquisition:

(in thousands)		
Fair value of net assets:		
Proved oil and natural gas properties	$	729,814
Unproved oil and natural gas properties		972,236
Other assets		34,000
Total assets acquired		1,736,050
Current liabilities, including current portion of asset retirement obligations		(8,225)
Asset retirement obligations assumed		(12,250)
Fair value of net assets acquired	$	1,715,575
Fair value of consideration paid for net assets:		
Cash consideration	$	1,175,708
Non-cash consideration, including equity		539,867
Total consideration paid for net assets	$	1,715,575

Southern Delaware Basin acquisition. In March 2016, the Company completed an acquisition of 80 percent of a third-party seller's interest in certain oil and natural gas properties and related assets in the southern Delaware Basin. As consideration for the acquisition, the Company issued to the seller approximately 2.2 million shares of common stock with an approximate value of $230.8 million, $145.7 million in cash and $40.0 million to carry a portion of the seller's future development costs in these properties.

Pro forma data. The following unaudited pro forma combined condensed financial data for the years ended December 31, 2016 and 2015, were derived from the historical financial statements of the Company giving effect to the Reliance Acquisition, as if it had occurred on January 1, 2015. The results of operations for the Reliance Acquisition are included in the Company's results of operations since the closing in October 2016 through December 31, 2016. The pro forma financial data does not include the results of operations for the southern Delaware Basin acquisition, as it was primarily an acreage acquisition and its results were not deemed material. The unaudited pro forma combined condensed financial data has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the Reliance Acquisition taken place as of the date indicated and is not intended to be a projection of future results.

	Years Ended December 31,	
(in thousands, except per share amounts)	**2016**	**2015**
	(unaudited)	
Operating revenues	$ 1,717,460	$ 1,976,356
Net income (loss)	$ (1,396,250)	$ 97,354
Earnings per common share:		
Basic net income (loss)	$ (10.36)	$ 0.81
Diluted net income (loss)	$ (10.36)	$ 0.80

Asset divestiture. In February 2016, the Company sold certain assets in the northern Delaware Basin for proceeds of approximately $292.0 million and recognized a pre-tax gain of approximately $110.1 million.

Clayton Williams Acreage Exchange. In December 2015, the Company completed a nonmonetary acreage exchange with Clayton Williams Energy, Inc. that consolidated acres into a concentrated, operated position in the southern Delaware Basin. The Company recognized a loss on disposition of assets of approximately $50.0 million related to the acreage exchange based on the fair value of the assets surrendered.

Note 5. ***Asset retirement obligations***

The Company's asset retirement obligations represent the estimated present value of the estimated cash flows the Company will incur to plug, abandon and remediate its producing properties at the end of their productive lives, in accordance with applicable state laws. Market risk premiums associated with asset retirement obligations are estimated to represent a component of the Company's credit-adjusted risk-free rate that is utilized in the calculations of asset retirement obligations.

The Company's asset retirement obligation transactions during the years ended December 31, 2016, 2015 and 2014 are summarized in the table below:

	Years Ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Asset retirement obligations, beginning of period	$ 119,945	$ 119,881	$ 101,593
Liabilities incurred from new wells	2,113	4,052	5,324
Liabilities assumed in acquisitions	13,217	2,434	4,065
Accretion expense	7,133	7,600	7,072
Disposition of wells	(10,955)	-	-
Liabilities settled upon plugging and abandoning wells	(1,063)	(2,736)	(2,926)
Revision of estimates (a)	-	(11,286)	4,753
Asset retirement obligations, end of period	$ 130,390	$ 119,945	$ 119,881

(a) The downward revision to the Company's asset retirement obligation estimates for the year ended December 31, 2015 is primarily due to a reduction in the future estimated abandonment costs.

Note 6. ***Incentive plans***

Defined contribution plan. The Company sponsors a 401(k) defined contribution plan for the benefit of substantially all employees. During the years ended December 31, 2016, 2015 and 2014, the Company matched 100 percent of employee contributions, not to exceed 10 percent of the employee's annual salary. The Company's contributions to the plan were approximately $9.5 million for each of the years ended December 31, 2016 and 2015 and approximately $8.1 million for the year ended December 31, 2014, of which a portion was recoverable from other working interest owners.

Stock incentive plan. The Company's 2015 Stock Incentive Plan (the "Plan") provides for granting stock options, restricted stock awards and performance awards to directors, officers and employees of the Company. A total of 10.5 million shares of common stock have been authorized for issuance under the Plan. At December 31, 2016, the Company had 2.4 million shares of common stock available for future grant.

Restricted stock awards. All restricted shares are legally issued and outstanding. If an employee terminates employment prior to the restriction lapse date, the awarded shares are forfeited and cancelled and are no longer considered issued and outstanding. A summary of the Company's restricted stock award activity for the year ended December 31, 2016 is presented below:

	Number of Restricted Shares	Weighted Average Grant Date Fair Value Per Share
Restricted stock:		
Outstanding at December 31, 2015	1,199,647	$ 110.14
Shares granted	450,981	$ 112.78
Shares cancelled / forfeited	(93,018)	$ 117.70
Lapse of restrictions	(400,340)	$ 96.48
Outstanding at December 31, 2016	1,157,270	$ 115.29

For restricted stock awards granted, stock-based compensation expense is being recognized in the Company's financial statements on an accelerated basis over the awards' vesting periods based on their fair values on the dates of grant. The restricted stock-based compensation awards generally vest over a period ranging from one to five years. The Company utilizes the average of the grant date's high and low stock prices for the fair value of restricted stock.

The following table summarizes information about stock-based compensation for the Company's restricted stock awards activity under the Plan for years ended December 31, 2016, 2015 and 2014:

	Years Ended December 31,		
(in thousands)	2016	2015	2014
Fair value for awards granted during the period (a)	$ 50,863	$ 49,659	$ 57,940
Fair value for awards vested during the period	$ 44,881	$ 35,700	$ 59,226
Stock-based compensation expense from restricted stock	$ 40,801	$ 43,185	$ 36,585
Income tax benefit related to restricted stock	$ 14,970	$ 16,049	$ 13,672

(a) The weighted average grant date fair value per share amounts were $112.78, $109.76, and $129.12 for the years ended December 31, 2016, 2015 and 2014, respectively.

Stock option awards. A summary of the Company's stock option award activity under the Plan for the year ended December 31, 2016 is presented below:

	Number of Options	Weighted Average Exercise Price
Stock options:		
Outstanding at December 31, 2015	42,901	$ 18.10
Options exercised	(22,901)	$ 20.52
Outstanding at December 31, 2016	20,000	$ 15.33
Vested and exercisable at December 31, 2016	20,000	$ 15.33

The intrinsic value of options exercised during 2016, 2015 and 2014 was approximately $2.3 million, $0.4 million and $23.2 million, respectively, based on the difference between the market price at the exercise date and the option exercise price.

The following table summarizes information about the Company's vested and exercisable stock options outstanding at December 31, 2016:

	December 31, 2016			
Exercise Prices	Number Vested	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Intrinsic Value of Options (in thousands)
Vested and exercisable options:				
$12.85	15,000	0.62 years	$ 12.85	$ 1,812
$22.77	5,000	1.81 years	$ 22.77	554
	20,000	0.92 years	$ 15.33	$ 2,366

The following table shows the deductions in current taxable income related to stock options exercised for the years ended December 31, 2016, 2015 and 2014:

	Years Ended December 31,		
(in thousands)	2016	2015	2014
Deductions in current taxable income related to stock options exercised	$ 271	$ 415	$ 23,208

Performance unit awards. During the years ended December 31, 2016, 2015 and 2014, the Company awarded performance units to its officers under the Plan. The number of shares of common stock that will ultimately be issued will be determined by a combination of (i) comparing the Company's total shareholder return relative to the total shareholder return of a predetermined group of peer companies at the end of the performance period and (ii) the Company's absolute total shareholder return at the end of the performance period. The performance period is 36 months. The grant date fair value was determined using the Monte Carlo simulation method and is being expensed ratably over the performance period. Expected volatilities utilized in the model were estimated using a historical period consistent with the remaining performance period of approximately three years. The risk-free interest rate was based on the United States Treasury rate for a term commensurate with the expected life of the grant.

The Company used the following assumptions to estimate the fair value of performance unit awards granted during the years ended December 31, 2016, 2015 and 2014:

	Years Ended December 31,		
	2016	2015	2014
Risk-free interest rate	1.31%	1.07%	0.76%
Range of volatilities	31.6% - 59.0%	26.1% - 43.0%	29.2% - 42.2%

The following table summarizes the performance unit activity for the year ended December 31, 2016:

	Number of Units		Grant Date Fair Value
Performance units:			
Outstanding at December 31, 2015	315,755	$	149.21
Units granted (a)	161,361	$	114.81
Units forfeited	(9,285)		140.66
Units vested (b)	(136,305)	$	139.54
Outstanding at December 31, 2016	331,526	$	136.68

(a) Reflects the amount of performance units granted. The actual payout of shares will be between zero and 300 percent of the performance units granted depending on the Company's performance at the end of the performance period.

(b) On December 31, 2016, the performance period ended for these performance units. Each unit converted into 1.825 shares representing 248,763 shares of common stock issued on January 2, 2017.

The following table summarizes information about stock-based compensation expense for performance units for the years ended December 31, 2016, 2015 and 2014:

	Years Ended December 31,					
(in thousands)		**2016**		**2015**		**2014**
Fair value for awards granted during the period (a)	$	18,526	$	27,659	$	19,455
Fair value for awards vested during the period	$	33,247	$	16,458	$	-
Stock-based compensation expense from performance units	$	18,126	$	19,888	$	10,545
Income tax benefit related to performance units	$	6,650	$	7,391	$	3,941

(a) The weighted average grant date fair value per unit amounts were $114.81, $156.86 and $139.54 for the years ended December 31, 2016, 2015 and 2014, respectively.

Future stock-based compensation expense. The following table reflects the future stock-based compensation expense to be recorded for all the stock-based compensation awards that were outstanding at December 31, 2016:

(in thousands)	Restricted Stock	Performance Units	Total
2017	$ 31,622	$ 13,369	$ 44,991
2018	17,140	5,469	22,609
2019	5,341	-	5,341
2020	423	-	423
2021	85	-	85
Thereafter	197	-	197
Total	$ 54,808	$ 18,838	$ 73,646

Note 7. *Disclosures about fair value measurements*

The Company uses a valuation framework based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources, whereas unobservable inputs reflect a company's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. These two types of inputs are further prioritized into the following fair value input hierarchy:

***Level 1*:** Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. The Company considers active markets to be those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

***Level 2*:** Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that the Company values using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace. Level 2 instruments primarily include non-exchange traded derivatives such as over-the-counter commodity price swaps, basis swaps, collars and floors, investments and interest rate swaps. The Company's valuation models are primarily industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value, (iii) current market and contractual prices for the underlying instruments and (iv) volatility factors, as well as other relevant economic measures.

***Level 3*:** Prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (*i.e.*, supported by little or no market activity). The Company's valuation models are primarily industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value, (iii) volatility factors and (iv) current market and contractual prices for the underlying instruments, as well as other relevant economic measures.

Financial Assets and Liabilities Measured at Fair Value

The following table presents the carrying amounts and fair values of the Company's financial instruments at December 31, 2016 and 2015:

	December 31, 2016		December 31, 2015	
(in thousands)	Carrying Value	Fair Value	Carrying Value	Fair Value
Assets:				
Derivative instruments	$ 3,551	$ 3,551	$ 819,536	$ 819,536
Liabilities:				
Derivative instruments	$ 177,949	$ 177,949	$ -	$ -
$600 million 7.0% senior notes due 2021 (a)	$ -	$ -	$ 592,414	$ 595,500
$600 million 6.5% senior notes due 2022 (a)	$ -	$ -	$ 591,549	$ 579,000
$600 million 5.5% senior notes due 2022 (a)	$ 593,787	$ 619,500	$ 592,899	$ 553,500
$1,550 million 5.5% senior notes due 2023 (a)	$ 1,554,710	$ 1,621,382	$ 1,555,326	$ 1,453,005
$600 million 4.375% senior notes due 2025 (a)	$ 592,083	$ 598,800	$ -	$ -

(a) The carrying value includes associated deferred loan costs and any premium.

Cash and cash equivalents, accounts receivable, other current assets, accounts payable, interest payable and other current liabilities. The carrying amounts approximate fair value due to the short maturity of these instruments.

Senior notes. The fair values of the Company's senior notes are based on quoted market prices. The debt securities are not actively traded and, therefore, are classified as Level 2 in the fair value hierarchy.

Derivative instruments. The fair value of the Company's derivative instruments is estimated by management considering various factors, including closing exchange and over-the-counter quotations and the time value of the underlying commitments. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The following tables summarize (i) the valuation of each of the Company's financial instruments by required fair value hierarchy levels and (ii) the gross fair value by the appropriate balance sheet classification, even when the derivative instruments are subject to netting arrangements and qualify for net presentation in the Company's consolidated balance sheets at December 31, 2016 and 2015. The Company nets the fair value of derivative instruments by counterparty in the Company's consolidated balance sheets.

	December 31, 2016					
	Fair Value Measurements Using					
(in thousands)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value	Gross Amounts Offset in the Consolidated Balance Sheet	Net Fair Value Presented in the Consolidated Balance Sheet
Assets						
Current:						
Commodity derivatives	$ -	$ 58,351	$ -	$ 58,351	$ (54,800)	$ 3,551
Noncurrent:						
Commodity derivatives	-	62	-	62	(62)	-
Liabilities						
Current:						
Commodity derivatives	-	(136,879)	-	(136,879)	54,800	(82,079)
Noncurrent:						
Commodity derivatives	-	(95,932)	-	(95,932)	62	(95,870)
Net derivative instruments	$ -	$ (174,398)	$ -	$ (174,398)	$ -	$ (174,398)

	December 31, 2015					
	Fair Value Measurements Using					
(in thousands)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value	Gross Amounts Offset in the Consolidated Balance Sheet	Net Fair Value Presented in the Consolidated Balance Sheet
Assets						
Current:						
Commodity derivatives	$ -	$ 684,029	$ -	$ 684,029	$ (31,531)	$ 652,498
Noncurrent:						
Commodity derivatives	-	175,267	-	175,267	(8,229)	167,038
Liabilities						
Current:						
Commodity derivatives	-	(31,531)	-	(31,531)	31,531	-
Noncurrent:						
Commodity derivatives	-	(8,229)	-	(8,229)	8,229	-
Net derivative instruments	$ -	$ 819,536	$ -	$ 819,536	$ -	$ 819,536

Concentrations of credit risk. At December 31, 2016, the Company's primary concentrations of credit risk are the risk of collecting accounts receivable and the risk of counterparties' failure to perform under derivative obligations. See Note 12 for information regarding the Company's major customers and derivative counterparties.

The Company has entered into International Swap Dealers Association Master Agreements ("ISDA Agreements") with each of its derivative counterparties. The terms of the ISDA Agreements provide the Company and the counterparties with rights of set-off upon the occurrence of defined acts of default by either the Company or a counterparty to a derivative, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party. See Note 8 for additional information regarding the Company's derivative activities.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are reported at fair value on a nonrecurring basis in the Company's consolidated balance sheets. The following methods and assumptions were used to estimate the fair values:

Impairments of long-lived assets – The Company periodically reviews its long-lived assets to be held and used, including proved oil and natural gas properties and their integrated assets, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable, for instance when there are declines in commodity prices or well performance. The Company reviews its oil and natural gas properties by depletion base. An impairment loss is indicated if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. If the estimated undiscounted future net cash flows are less than the carrying amount of the Company's assets, it recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset.

The Company calculates the expected undiscounted future net cash flows of its long-lived assets and their integrated assets using management's assumptions and expectations of (i) commodity prices, which are based on the New York Mercantile Exchange ("NYMEX") strip, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) production volumes, (vi) estimated proved reserves and risk-adjusted probable and possible reserves, and (vii) prevailing market rates of income and expenses from integrated assets. At December 31, 2016, the Company's estimates of commodity prices for purposes of determining undiscounted future cash flows, which are based on the NYMEX strip, ranged from a 2017 price of \$56.19 per barrel of oil to a 2024 price of \$57.41 per barrel of oil. Similarly, gas prices ranged from a 2017 price of \$3.61 per Mcf of natural gas decreasing to a 2020 price of \$2.88 per Mcf partially recovering to a 2024 price of \$3.38 per Mcf of natural gas. Commodity prices for this purpose were held flat after 2024.

The Company calculates the estimated fair values of its long-lived assets and their integrated assets using a discounted future cash flow model. Fair value assumptions associated with the calculation of discounted future net cash flows include (i) market estimates of commodity prices, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) production volumes, (vi) estimated proved reserves and risk-adjusted probable and possible reserves, (vii) prevailing market rates of income and expenses from integrated assets and (viii) discount rate. The expected future net cash flows were discounted using an annual rate of 10 percent to determine fair value. These are classified as Level 3 fair value assumptions.

During the three months ended March 31, 2016, NYMEX strip prices declined as compared to December 31, 2015, and as a result the carrying amount of the Company's Yeso field of approximately \$3.4 billion exceeded the expected undiscounted future net cash flows resulting in a non-cash charge against earnings of approximately \$1.5 billion. The non-cash charge represented the amount by which the carrying amount exceeded the estimated fair value of the assets.

The following table reports the carrying amount, estimated fair value and impairment expense of long-lived assets for the indicated periods:

(in thousands)	Carrying Amount	Estimated Fair Value (Level 3)	Impairment Expense
March 2016	$ 3,437,612	$ 1,912,967	$ 1,524,645
December 2015	$ 104,982	$ 52,041	$ 52,941
September 2015	$ 18,023	$ 10,435	$ 7,588
December 2014	$ 677,021	$ 245,346	$ 431,675
September 2014	$ 26,790	$ 11,314	$ 15,476

It is reasonably possible that the estimate of undiscounted future net cash flows of the Company's long-lived assets may change in the future resulting in the need to impair carrying values. The primary factors that may affect estimates of future cash flows are (i) commodity prices including differentials, (ii) increases or decreases in production and capital costs, (iii) future reserve volume adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves, (iv) results of future drilling activities and (v) changes in income and expenses from integrated assets.

Note 8. ***Derivative financial instruments***

The Company uses derivative financial instruments to manage its exposure to commodity price fluctuations. Commodity derivative instruments are used to (i) reduce the effect of the volatility of price changes on the oil and natural gas the Company produces and sells, (ii) support the Company's capital budget and expenditure plans and (iii) support the economics associated with acquisitions. The Company does not enter into derivative financial instruments for speculative or trading purposes. The Company may also enter into physical delivery contracts to effectively provide commodity price hedges. Because these physical delivery contracts are not expected to be net cash settled, they are considered to be normal sales contracts and not derivatives. Therefore, these contracts are not recorded in the Company's consolidated financial statements.

The Company does not designate its derivative instruments to qualify for hedge accounting. Accordingly, the Company reflects changes in the fair value of its derivative instruments in its statements of operations as they occur.

The following table summarizes the amounts reported in earnings related to the commodity derivative instruments for the years ended December 31, 2016, 2015 and 2014:

	Years Ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Gain (loss) on derivatives:			
Oil derivatives	$ (337,175)	$ 675,303	$ 869,421
Natural gas derivatives	(31,509)	24,449	21,496
Total	$ (368,684)	$ 699,752	$ 890,917

The following table represents the Company's net cash receipts from (payments on) derivatives for the years ended December 31, 2016, 2015 and 2014:

	Years Ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Net cash receipts from (payments on) derivatives:			
Oil derivatives	$ 608,847	$ 597,297	$ 76,335
Natural gas derivatives	16,403	35,619	(4,352)
Total	$ 625,250	$ 632,916	$ 71,983

Commodity derivative contracts at December 31, 2016. The following table sets forth the Company's outstanding derivative contracts at December 31, 2016. When aggregating multiple contracts, the weighted average contract price is disclosed. All of the Company's derivative contracts at December 31, 2016 are expected to settle by December 31, 2018.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Swaps: (a)					
2017:					
Volume (Bbl)	7,020,870	6,348,480	5,854,370	5,465,080	24,688,800
Price per Bbl	$ 57.00	$ 57.66	$ 51.25	$ 51.48	$ 54.58
2018:					
Volume (Bbl)	5,139,629	4,864,170	4,624,318	4,418,007	19,046,124
Price per Bbl	$ 51.63	$ 51.46	$ 51.28	$ 51.12	$ 51.38
Oil Basis Swaps: (b)					
2017:					
Volume (Bbl)	6,603,000	6,141,500	5,290,000	5,290,000	23,324,500
Price per Bbl	$ (1.00)	$ (1.03)	$ (0.49)	$ (0.49)	$ (0.78)
2018:					
Volume (Bbl)	2,340,000	2,366,000	2,392,000	2,392,000	9,490,000
Price per Bbl	$ (0.98)	$ (0.98)	$ (0.98)	$ (0.98)	$ (0.98)
Natural Gas Swaps: (c)					
2017:					
Volume (MMBtu)	14,461,315	13,289,642	12,365,441	11,743,000	51,859,398
Price per MMBtu	$ 3.07	$ 3.05	$ 3.05	$ 3.04	$ 3.06
2018:					
Volume (MMBtu)	5,506,000	5,216,000	5,029,000	4,844,000	20,595,000
Price per MMBtu	$ 3.04	$ 3.04	$ 3.03	$ 3.03	$ 3.03

(a) The index prices for the oil price swaps are based on the NYMEX – West Texas Intermediate ("WTI") monthly average futures price.
(b) The basis differential price is between Midland – WTI and Cushing – WTI.
(c) The index prices for the natural gas price swaps are based on the NYMEX – Henry Hub last trading day futures price.

Derivative counterparties. The Company uses credit and other financial criteria to evaluate the creditworthiness of counterparties to its derivative instruments. The Company believes that all of its derivative counterparties are currently acceptable credit risks. Other than provided by the Company's credit facility, the Company is not required to provide credit support or collateral to any counterparties under its derivative contracts, nor are they required to provide credit support to the Company. Under the terms of the Company's credit facility, certain events could occur that would cause any obligations under the Company's credit facility to no longer be secured by the Company's oil and natural gas properties. In this circumstance, the Company has certain agreements in place with the Company's derivative counterparties that would regulate collateral related to derivative transactions. See additional information in Note 12.

Note 9. ***Debt***

The Company's debt consisted of the following at December 31, 2016 and 2015:

	December 31,	
(in thousands)	**2016**	**2015**
Credit facility	$ -	$ -
7.0% unsecured senior notes due 2021	-	600,000
6.5% unsecured senior notes due 2022	-	600,000
5.5% unsecured senior notes due 2022	600,000	600,000
5.5% unsecured senior notes due 2023	1,550,000	1,550,000
4.375% unsecured senior notes due 2025	600,000	-
Unamortized original issue premium	22,173	25,073
Senior notes issuance costs, net	(31,593)	(42,885)
Less: current portion	-	-
Total long-term debt	$ 2,740,580	$ 3,332,188

Credit facility. The Company's credit facility, as amended and restated (the "Credit Facility"), has a maturity date of May 9, 2019. At December 31, 2016, the Company's commitments from its bank group were $2.5 billion. The Company expects it will maintain its $2.5 billion in commitments until its next scheduled redetermination in May 2017. At December 31, 2016, the Company's borrowing base was $2.8 billion. Between scheduled borrowing base redeterminations, the Company and the lenders (requiring a 66 2/3 percent vote), may each request one special redetermination.

Advances on the Credit Facility bear interest, at the Company's option, based on (i) the prime rate of JPMorgan Chase Bank ("JPM Prime Rate") (3.75 percent at December 31, 2016) or (ii) a Eurodollar rate (substantially equal to the LIBOR). At December 31, 2016, the interest rates of Eurodollar rate advances and JPM Prime Rate advances varied, with interest margins ranging from 125 to 225 basis points and 25 to 125 basis points per annum, respectively, depending on the balance outstanding on the Credit Facility. During the years ended December 31, 2016, 2015 and 2014, the Company incurred commitment fees on the unused portion of the available commitments of $7.6 million, $7.0 million and $7.7 million, respectively. Under the current Credit Facility, commitment fees range from 30 to 37.5 basis points per annum. The Company had $2.5 billion of unused commitments under its credit facility at December 31, 2016.

The Company's obligations under the Credit Facility are secured by a first lien on substantially all of its oil and natural gas properties. Under the terms of the Credit Facility, if the Company receives certain upgrades to its credit rating, any obligations under the Credit Facility could no longer be secured by the Company's oil and natural gas properties based on certain provisions. At December 31, 2016, certain of the Company's subsidiaries are guarantors and have had their equity pledged to secure borrowings under the Credit Facility.

The Credit Facility contains various restrictive covenants and compliance requirements which include:

- maintenance of a quarterly ratio of total debt to consolidated earnings before interest expense, income taxes, depletion, depreciation, and amortization, exploration expense and other noncash income and expenses to be no greater than 4.25 to 1.0;
- limits on the incurrence of certain indebtedness and certain types of liens;
- restrictions as to mergers, combinations and dispositions of assets; and
- limits on the payment of cash dividends.

Senior notes. Interest on the Company's senior notes is paid in arrears semi-annually. The senior notes are fully and unconditionally guaranteed on a senior unsecured basis by certain subsidiaries of the Company, subject to customary release provisions as described in Note 16.

In December 2016, the Company issued $600 million in aggregate principal amount of 4.375% senior notes due 2025 at par, for which it received net proceeds of approximately $592.1 million. The Company used the net proceeds from the offering to fund the satisfaction and discharge of its obligations under the indenture of the $600 million outstanding principal amount of its 6.5% unsecured senior notes due 2022 (the "6.5% Notes") at a price equal to 103.25 percent of par. The early extinguishment price included the make-whole premium as determined in accordance with the indenture governing the 6.5% Notes. In December 2016, the Company also paid interest of approximately $19.6 million on the 6.5% Notes through January 16, 2017.

The Company recorded a loss on extinguishment of debt related to the 6.5% Notes of approximately $28.7 million for the year ended December 31, 2016. This amount includes $19.5 million associated with the make-whole premium paid for the early extinguishment of the notes, approximately $7.3 million of unamortized deferred loan costs and approximately $1.9 million of additional interest on the 6.5% Notes through January 16, 2017, which was paid in December 2016.

In September 2016, the Company redeemed the $600 million outstanding principal amount of its 7.0% unsecured senior notes due 2021 (the "7.0% Notes") at a price equal to 103.5 percent of par. The redemption price included the make-whole premium for the early redemption, as determined in accordance with the indenture governing the 7.0% Notes. The Company also paid accrued and unpaid interest on the 7.0% Notes through September 19, 2016, the redemption date.

The Company recorded a loss on extinguishment of debt related to the redemption of the 7.0% Notes of approximately $27.7 million for the year ended December 31, 2016. This amount includes $21.0 million associated with the make-whole premium paid for the early redemption of the notes and approximately $6.7 million of unamortized deferred loan costs.

At December 31, 2016, the Company was in compliance with the covenants under all of its debt instruments.

Principal maturities of long-term debt. Principal maturities of long-term debt outstanding at December 31, 2016 were as follows:

(in thousands)	
2017	$ -
2018	-
2019	-
2020	-
2021	-
Thereafter	2,750,000
Total	$ 2,750,000

Interest expense. The following amounts have been incurred and charged to interest expense for the years ended December 31, 2016, 2015 and 2014:

	Years Ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Cash payments for interest	$ 232,173	$ 211,443	$ 211,342
Amortization of original issue premium	(2,900)	(2,747)	(2,599)
Amortization of deferred loan origination costs	9,937	9,971	10,937
Accretion expense	1,939	1,795	-
Net changes in accruals	(37,379)	(165)	(737)
Interest costs incurred	203,770	220,297	218,943
Less: capitalized interest	(252)	(4,913)	(2,282)
Total interest expense	$ 203,518	$ 215,384	$ 216,661

Note 10. *Commitments and contingencies*

Severance agreements. The Company has entered into severance and change in control agreements with all of its officers. The current annual salaries for the Company's officers covered under such agreements total approximately $7.4 million.

Indemnifications. The Company has agreed to indemnify its directors and officers with respect to claims and damages arising from certain acts or omissions taken in such capacity.

Legal actions. The Company is a party to proceedings and claims incidental to its business. While many of these matters involve inherent uncertainty, the Company believes that the amount of the liability, if any, ultimately incurred with respect to any such proceedings or claims will not have a material adverse effect on the Company's consolidated financial position as a whole or on its liquidity, capital resources or future results of operations. The Company will continue to evaluate proceedings and claims involving the Company on a regular basis and will establish and adjust any reserves as appropriate to reflect its assessment of the then current status of the matters.

Severance tax, royalty and joint interest audits. The Company is subject to routine severance, royalty and joint interest audits from regulatory bodies and non-operators and makes accruals as necessary for estimated exposure when deemed probable and estimable. Additionally, the Company is subject to various possible contingencies that arise primarily from interpretations 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, allowable costs under joint interest arrangements and other matters. At December 31, 2016 and 2015, the Company had $7.1 million and $13.4 million, respectively, accrued for estimated exposure. Although the Company believes that it has estimated its exposure with respect to the various laws and regulations, administrative rulings and interpretations thereof, adjustments could be required as new interpretations and regulations are issued.

Commitments. The Company periodically enters into contractual arrangements under which the Company is committed to expend funds. These contractual arrangements relate to purchase agreements the Company has entered into including drilling commitments, water commitment agreements, throughput volume delivery commitments, power commitments, fixed asset commitments and maintenance commitments. The following table summarizes the Company's commitments at December 31, 2016:

(in thousands)	
2017	$ 56,649
2018	69,195
2019	49,327
2020	24,669
2021	20,770
Thereafter	97,869
Total	$ 318,479

Operating leases. The Company leases vehicles, equipment and office facilities under non-cancellable operating leases. Lease payments associated with these operating leases for the years ended December 31, 2016, 2015 and 2014 were approximately $8.4 million, $8.0 million and $7.2 million, respectively.

Future minimum lease commitments under non-cancellable operating leases at December 31, 2016 were as follows:

(in thousands)	
2017	$ 8,988
2018	7,945
2019	6,419
2020	4,966
2021	4,088
Thereafter	1,002
Total	$ 33,408

Note 11. *Income taxes*

The Company uses an asset and liability approach for financial accounting and reporting for income taxes. The Company's objectives of accounting for income taxes are to recognize (i) the amount of taxes payable or refundable for the current year and (ii) deferred tax liabilities and assets for the future tax consequences of events that have been recognized in its financial statements or tax returns. The Company and its subsidiaries file a federal corporate income tax return on a consolidated basis. The tax returns and the amount of taxable income or loss are subject to examination by federal and state taxing authorities. At December 31, 2016, the Company had current income taxes receivable of approximately $4.5 million. At December 31, 2015, the Company had current income taxes receivable of approximately $37.3 million and current income taxes payable of approximately $1.0 million.

At December 31, 2016, the Company did not have any significant uncertain tax positions requiring recognition in the financial statements. The tax years 2013 through 2016 remain subject to examination by the major tax jurisdictions.

Income tax expense (benefit). The Company's income tax expense (benefit) and amounts separately allocated were attributable to the following items for the years ended December 31, 2016, 2015 and 2014:

	Years Ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Consolidated statements of operations:			
Income tax expense (benefit) from operations	$ (876,090)	$ 31,371	$ 317,785
Consolidated statements of stockholders' equity:			
Excess tax deficiency (benefit) related to stock-based compensation	669	(2,150)	(16,480)
	$ (875,421)	$ 29,221	$ 301,305

The Company's income tax expense (benefit) attributable to income (loss) from operations consisted of the following for the years ended December 31, 2016, 2015 and 2014:

	Years Ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Current:			
U.S. federal	$ (11,579)	$ 127	$ 16,621
U.S. state and local	(170)	1,622	4,997
Total current income tax expense (benefit)	(11,749)	1,749	21,618
Deferred:			
U.S. federal	(770,734)	40,364	278,615
U.S. state and local	(93,607)	(10,742)	17,552
Total deferred income tax expense (benefit)	(864,341)	29,622	296,167
Total income tax expense (benefit) attributable to income from operations	$ (876,090)	$ 31,371	$ 317,785

The reconciliation between the income tax expense (benefit) computed by multiplying pre-tax income (loss) from operations by the United States federal statutory rate and the reported amounts of income tax expense (benefit) from operations is as follows:

	Years Ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Income (loss) at U.S. federal statutory rate	$ (818,488)	$ 34,045	$ 299,586
State income taxes (net of federal tax effect)	(40,015)	3,071	22,826
Revisions of previous estimates	746	(631)	738
Change in estimated effective statutory state income tax	(20,909)	(9,026)	(7,945)
Nondeductible expense & other	2,576	3,912	2,580
Income tax expense (benefit)	$ (876,090)	$ 31,371	$ 317,785
Effective tax rate	(37.5)%	32.3%	37.1%

The Company monitors changes in enacted tax rates for the jurisdictions in which it operates. The Company monitors its state tax apportionment footprint and makes updates for changes in its projected activity, including changes in budgets and drilling plans. During 2013, the state of New Mexico passed legislation to phase in a tax rate reduction over the next five years. In June of 2015, the State of Texas enacted legislation to reduce its rate. In October 2016, the Company purchased Texas-based assets in the Reliance Acquisition for approximately $1.7 billion, which caused a shift in the Company's projected future apportionment from New Mexico to Texas. Therefore, based upon the Company's projected future activity for the states in which it conducts business, the timing for when it anticipates its deferred tax items to become taxable and enacted tax rates at such time deferred items become taxable, the Company has revised its estimated state rate and recorded an additional deferred state tax benefit of $20.9 million, $9.0 million and $7.9 million during 2016, 2015 and 2014, respectively.

The Company's effective tax rate increased in 2016 as compared with 2015 primarily due to a shift from pre-tax earnings of $97.3 million in 2015 to a pre-tax loss of $2.3 billion in 2016, resulting in a less pronounced effect on the effective tax rate for each reconciling item. In particular, the reduction in the Company's effective statutory state rate caused a 0.9 percent increase in 2016 as compared to a 9.3 percent reduction in 2015, partially offset by other reconciling and non-deductible items for a net rate increase of 5.2 percent over 2015.

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities were as follows:

	December 31,	
(in thousands)	**2016**	**2015**
Deferred tax assets:		
Stock-based compensation	$ 39,192	$ 36,738
Derivative instruments	63,986	-
Asset retirement obligation	47,840	44,573
Net operating losses and credits	177,264	194
Other	23,850	29,380
Total deferred tax assets	352,132	110,885
Deferred tax liabilities:		
Oil and natural gas properties, principally due to differences in basis and depreciation and the deduction of intangible drilling costs for tax purposes	(1,095,173)	(1,420,275)
Intangible assets - operating rights	(8,891)	(9,548)
Derivative instruments	-	(304,550)
Other	(14,100)	(6,885)
Total deferred tax liability	(1,118,164)	(1,741,258)
Net deferred tax liability	$ (766,032)	$ (1,630,373)

The Company had net deferred tax liabilities of approximately $766.0 million and $1.6 billion as of December 31, 2016 and December 31, 2015, respectively.

At December 31, 2016, the Company had approximately $477.7 million of federal net operating losses ("NOLs") expiring in 2036, of which $12.6 million is due to stock-based compensation awards. The Company has estimated an apportioned New Mexico NOL of $248.2 million expiring in 2035 through 2036, of which $8.5 million is due to stock-based compensation awards. In accordance with applicable accounting standards as of December 31, 2016, a financial statement benefit has not been recorded for the NOLs related to the stock-based compensation awards. As discussed in Note 2, upon the adoption of ASU 2016-09, the Company will record this tax benefit during the first quarter of 2017. In addition, the Company's tax attributes at December 31, 2016 include $4.8 million of alternative minimum tax credits that are not subject to expiration and $6.0 million of charitable contribution carryforwards first expiring after 2020.

Pursuant to management's assessment, the Company does not believe a cumulative ownership change has occurred as of December 31, 2016. As such, Section 382 of the Internal Revenue Code of 1986, as amended, is not expected to limit the Company's ability to utilize its NOL carryforward as of December 31, 2016.

Management monitors company-specific, oil and natural gas industry and worldwide economic factors and assesses the likelihood that the Company's NOLs and other deferred tax attributes will be utilized prior to their expiration. At December 31, 2016, management considered all factors including the expected reversal of deferred tax liabilities (including the impact of available carryback and carryforward periods), historical operating income, tax planning strategies and projected future taxable income. Based on the results of the assessment, management determined that it is more likely than not that the Company will realize its deferred tax assets.

Note 12. ***Major customers and derivative counterparties***

Sales to major customers. The Company's share of oil and natural gas production is sold to various purchasers. The Company is of the opinion that the loss of any one purchaser would not have a material adverse effect on the ability of the Company to sell its oil and natural gas production.

The following purchasers individually accounted for 10 percent or more of the consolidated oil and natural gas revenues during the years ended December 31, 2016, 2015 and 2014:

	Years Ended December 31,		
	2016	2015	2014
Plains Marketing and Transportation, Inc.	29%	11%	6%
Holly Frontier Refining and Marketing, LLC	16%	25%	17%
Enterprise Crude Oil LLC	7%	12%	12%
Western Refining Company LP	-	5%	12%

At December 31, 2016, the Company had receivables from Plains Marketing & Transportation Inc., Holly Frontier Refining and Marketing, LLC, Enterprise Crude Oil LLC, and Western Refining Company LP of $48.1 million, $26.5 million, $23.7 million and $0.4 million, respectively, which are reflected in accounts receivable — oil and natural gas in the accompanying consolidated balance sheets.

Derivative counterparties. The Company uses credit and other financial criteria to evaluate the creditworthiness of counterparties to its derivative instruments. The Credit Facility requires that the senior unsecured debt ratings of the Company's derivative counterparties be (i) not less than either A- by S&P Global Ratings rating system or A3 by Moody's Investors Service, Inc. rating system or (ii) a lender or related affiliate under the Credit Facility. At December 31, 2016 and 2015, the counterparties with whom the Company had outstanding derivative contracts met or exceeded these criteria. Although the Company does not obtain collateral or otherwise secure the fair value of its derivative instruments, management believes the associated credit risk is mitigated by the Company's credit risk policies and procedures and by the criteria of the Credit Facility. Under the terms of the Credit Facility, certain events could occur that would cause any obligations under the Credit Facility to no longer be secured by the Company's oil and natural gas properties. In this circumstance, the Company has certain agreements in place with the Company's derivative counterparties that would regulate collateral related to derivative transactions.

Note 13. ***Related party transactions***

The following table summarizes amounts paid to and received from related parties and reported in the Company's consolidated statements of operations for the periods presented:

	Years Ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Amounts paid to a partnership in which a director has an ownership interest (a)	$ 4,374	$ 5,745	$ 15,181
Amounts paid to a director and certain officers of the Company (b)	$ 349	$ 593	$ 383
Amounts received from certain officers of the Company (c)	$ 36	$ 237	$ 169

(a) Amounts include royalties on certain properties and lease bonus payments paid to a partnership in which a director of the Company is the general partner and owns a 3.5 percent partnership interest.

(b) Amounts include revenue interests, overriding royalty interests and net profits interests in properties owned by the Company made to a director and certain officers (or affiliated entities). Amounts also include payments for an acreage acquisition and lease bonuses to an affiliated entity of an officer.

(c) Amounts include payments to the Company as a result of activity on oil and natural gas properties in which certain officers (or affiliated entities) have an interest.

Note 14. ***Earnings per share***

The Company uses the two-class method of calculating earnings per share because certain of the Company's unvested share-based awards qualify as participating securities.

The following table reconciles the Company's earnings from operations and earnings attributable to common stockholders to the basic and diluted earnings used to determine the Company's earnings per share amounts for the years ended December 31, 2016, 2015 and 2014, respectively, under the two-class method:

	Years Ended December 31,		
(in thousands, except per share amounts)	**2016**	**2015**	**2014**
Net income (loss) as reported	$ (1,462,446)	$ 65,900	$ 538,175
Participating basic earnings (a)	-	(635)	(5,961)
Basic earnings attributable to common stockholders	(1,462,446)	65,265	532,214
Reallocation of participating earnings	-	2	16
Diluted earnings attributable to common stockholders	$ (1,462,446)	$ 65,267	$ 532,230
Earnings per common share:			
Basic	$ (10.85)	$ 0.54	$ 4.89
Diluted	$ (10.85)	$ 0.54	$ 4.88

(a) Unvested restricted stock awards represent participating securities because they participate in nonforfeitable dividends or distributions with the common equity holders of the Company. Participating earnings represent the distributed earnings of the Company attributable to the participating securities. Unvested restricted stock awards do not participate in undistributed net losses as they are not contractually obligated to do so.

The following table is a reconciliation of the basic weighted average common shares outstanding to diluted weighted average common shares outstanding for the years ended December 31, 2016, 2015 and 2014:

	Years Ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Weighted average common shares outstanding:			
Basic	134,755	119,926	108,844
Dilutive common stock options	-	25	83
Dilutive performance units	-	422	205
Diluted	134,755	120,373	109,132

Note 15. ***Other current liabilities***

The following table provides the components of the Company's other current liabilities at December 31, 2016 and 2015:

	December 31,	
(in thousands)	**2016**	**2015**
Other current liabilities:		
Accrued production costs	$ 62,573	$ 70,876
Payroll related matters	34,647	29,411
Accrued interest	31,719	68,925
Asset retirement obligations	10,035	8,626
Other	12,596	7,072
Other current liabilities	$ 151,570	$ 184,910

Note 16. ***Subsidiary guarantors***

At December 31, 2016, certain of the Company's 100 percent owned subsidiaries have fully and unconditionally guaranteed the Company's senior notes. The indentures governing the Company's senior notes provide that the guarantees of its subsidiary guarantors will be released in certain customary circumstances including (i) in connection with any sale, exchange or other disposition, whether by merger, consolidation or otherwise, of the capital stock of that guarantor to a person that is not the Company or a restricted subsidiary of the Company, such that, after giving effect to such transaction, such guarantor would no longer constitute a subsidiary of the Company, (ii) in connection with any sale, exchange or other disposition (other than a lease) of all or substantially all of the assets of that guarantor to a person that is not the Company or a restricted subsidiary of the Company, (iii) upon the merger of a guarantor into the Company or any other guarantor or the liquidation or dissolution of a guarantor, (iv) if the Company designates any restricted subsidiary that is a guarantor to be an unrestricted subsidiary in accordance with the indenture, (v) upon legal defeasance or satisfaction and discharge of the indenture and (vi) upon written notice of such release or discharge by the Company to the trustee following the release or discharge of all guarantees by such guarantor of any indebtedness that resulted in the creation of such guarantee, except a discharge or release by or as a result of payment under such guarantee.

See Note 9 for a summary of the Company's senior notes. In accordance with practices accepted by the United States Securities and Exchange Commission ("SEC"), the Company has prepared condensed consolidating financial statements in order to quantify the assets, results of operations and cash flows of such subsidiaries as subsidiary guarantors.

The following condensed consolidating balance sheets at December 31, 2016 and 2015, condensed consolidating statements of operations and condensed consolidating statements of cash flows for the years ended December 31, 2016, 2015 and 2014, present financial information for Concho Resources Inc. as the parent on a stand-alone basis (carrying any investments in subsidiaries under the equity method), financial information for the subsidiary guarantors on a stand-alone basis and the consolidation and elimination entries necessary to arrive at the information for the Company on a consolidated basis. All current and deferred income taxes are recorded on Concho Resources Inc., as the subsidiaries are flow-through entities for income tax purposes. The subsidiary guarantors are not restricted from making distributions to the Company.

Condensed Consolidating Balance Sheet
December 31, 2016

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
ASSETS				
Accounts receivable - related parties	$ 8,991,238	$ (335,771)	$ (8,655,467)	$ -
Other current assets	12,519	533,975	-	546,494
Oil and natural gas properties, net	-	11,086,435	-	11,086,435
Property and equipment, net	-	215,998	-	215,998
Investment in subsidiaries	1,988,962	-	(1,988,962)	-
Other long-term assets	10,909	259,490	-	270,399
Total assets	$ 11,003,628	$ 11,760,127	$ (10,644,429)	$ 12,119,326
LIABILITIES AND EQUITY				
Accounts payable - related parties	$ (335,771)	$ 8,991,238	$ (8,655,467)	$ -
Other current liabilities	114,224	638,962	-	753,186
Long-term debt	2,740,580	-	-	2,740,580
Other long-term liabilities	861,902	140,965	-	1,002,867
Equity	7,622,693	1,988,962	(1,988,962)	7,622,693
Total liabilities and equity	$ 11,003,628	$ 11,760,127	$ (10,644,429)	$ 12,119,326

Condensed Consolidating Balance Sheet
December 31, 2015

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
ASSETS				
Accounts receivable - related parties	$ 8,502,099	$ 1,162,297	$ (9,664,396)	$ -
Other current assets	753,716	560,834	-	1,314,550
Oil and natural gas properties, net	-	10,798,497	-	10,798,497
Property and equipment, net	-	178,450	-	178,450
Investment in subsidiaries	3,698,485	-	(3,698,485)	-
Other long-term assets	182,623	167,756	-	350,379
Total assets	$ 13,136,923	$ 12,867,834	$ (13,362,881)	$ 12,641,876
LIABILITIES AND EQUITY				
Accounts payable - related parties	$ 1,162,297	$ 8,502,099	$ (9,664,396)	$ -
Other current liabilities	69,514	526,906	-	596,420
Long-term debt	3,332,188	-	-	3,332,188
Other long-term liabilities	1,630,373	140,344	-	1,770,717
Equity	6,942,551	3,698,485	(3,698,485)	6,942,551
Total liabilities and equity	$ 13,136,923	$ 12,867,834	$ (13,362,881)	$ 12,641,876

Concho Resources Inc.
Notes to Consolidated Financial Statements
December 31, 2016, 2015 and 2014

Condensed Consolidating Statement of Operations
For the Year Ended December 31, 2016

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Total operating revenues	$ -	$ 1,634,988	$ -	$ 1,634,988
Total operating costs and expenses	(370,824)	(3,333,608)	-	(3,704,432)
Loss from operations	(370,824)	(1,698,620)	-	(2,069,444)
Interest expense	(201,753)	(1,765)	-	(203,518)
Loss on extinguishment of debt	(56,436)	-	-	(56,436)
Other, net	(1,709,523)	(9,138)	1,709,523	(9,138)
Loss before income taxes	(2,338,536)	(1,709,523)	1,709,523	(2,338,536)
Income tax benefit	876,090	-	-	876,090
Net loss	$ (1,462,446)	$ (1,709,523)	$ 1,709,523	$ (1,462,446)

Condensed Consolidating Statement of Operations
For the Year Ended December 31, 2015

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Total operating revenues	$ -	$ 1,803,573	$ -	$ 1,803,573
Total operating costs and expenses	697,247	(2,173,606)	-	(1,476,359)
Income (loss) from operations	697,247	(370,033)	-	327,214
Interest expense	(213,416)	(1,968)	-	(215,384)
Other, net	(386,560)	(14,559)	386,560	(14,559)
Income (loss) before income taxes	97,271	(386,560)	386,560	97,271
Income tax expense	(31,371)	-	-	(31,371)
Net income (loss)	$ 65,900	$ (386,560)	$ 386,560	$ 65,900

Condensed Consolidating Statement of Operations
For the Year Ended December 31, 2014

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Total operating revenues	$ -	$ 2,660,147	$ -	$ 2,660,147
Total operating costs and expenses	888,632	(2,468,342)	-	(1,579,710)
Income from operations	888,632	191,805	-	1,080,437
Interest expense	(216,661)	-	-	(216,661)
Loss on extinguishment of debt	(4,316)	-	-	(4,316)
Other, net	188,305	(3,501)	(188,304)	(3,500)
Income before income taxes	855,960	188,304	(188,304)	855,960
Income tax expense	(317,785)	-	-	(317,785)
Net income	$ 538,175	$ 188,304	$ (188,304)	$ 538,175

Condensed Consolidating Statement of Cash Flows
For the Year Ended December 31, 2016

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Net cash flows provided by (used in) operating activities	$ (664,870)	$ 2,049,318	$ -	$ 1,384,448
Net cash flows used in investing activities	-	(2,224,656)	-	(2,224,656)
Net cash flows provided by financing activities	664,919	-	-	664,919
Net increase (decrease) in cash and cash equivalents	49	(175,338)	-	(175,289)
Cash and cash equivalents at beginning of period	-	228,550	-	228,550
Cash and cash equivalents at end of period	$ 49	$ 53,212	$ -	$ 53,261

Condensed Consolidating Statement of Cash Flows
For the Year Ended December 31, 2015

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Net cash flows provided by (used in) operating activities	$ (1,393,290)	$ 2,923,711	$ -	$ 1,530,421
Net cash flows used in investing activities	-	(2,602,641)	-	(2,602,641)
Net cash flows provided by (used in) financing activities	1,393,290	(92,541)	-	1,300,749
Net increase in cash and cash equivalents	-	228,529	-	228,529
Cash and cash equivalents at beginning of period	-	21	-	21
Cash and cash equivalents at end of period	$ -	$ 228,550	$ -	$ 228,550

Condensed Consolidating Statement of Cash Flows
For the Year Ended December 31, 2014

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Net cash flows provided by (used in) operating activities	$ (816,386)	$ 2,562,156	$ -	$ 1,745,770
Net cash flows used in investing activities	-	(2,617,979)	-	(2,617,979)
Net cash flows provided by financing activities	816,386	55,823	-	872,209
Net increase (decrease) in cash and cash equivalents	-	-	-	-
Cash and cash equivalents at beginning of period	-	21	-	21
Cash and cash equivalents at end of period	$ -	$ 21	$ -	$ 21

Note 17. ***Subsequent events***

ACC divestiture. In January 2017, the Company and its joint venture partner entered into separate agreements to sell 100 percent of their respective ownership interests in ACC for a combined total of $1.215 billion. After adjustments for debt and working capital, the Company received net cash proceeds from the sale of approximately $802.8 million. The Company's net investment in ACC was approximately $128.7 million at December 31, 2016. The transaction closed in February 2017 and is subject to customary post-closing adjustments.

Northern Delaware Basin acquisition. In January 2017, the Company completed a portion of the previously announced acquisition of approximately 16,400 net acres in the northern Delaware Basin. As consideration for the entire acquisition, the Company agreed to issue to the seller approximately 2.2 million shares of its common stock and $150.0 million in cash. The Company expects to close on the remainder of the acquisition during the first half of 2017 and the acquisition, in its entirety, is subject to customary closing and post-closing adjustments.

New commodity derivative contracts. After December 31, 2016, the Company entered into the following additional oil price swaps to hedge additional amounts of the Company's estimated future production:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Swaps: (a)					
2017:					
Volume (Bbl)	403,000	1,360,000	1,044,000	868,000	3,675,000
Price per Bbl	$ 55.32	$ 55.20	$ 55.36	$ 55.56	$ 55.34
2018:					
Volume (Bbl)	736,000	652,000	580,000	523,000	2,491,000
Price per Bbl	$ 55.47	$ 55.48	$ 55.54	$ 55.61	$ 55.52
2019:					
Volume (Bbl)	2,355,000	2,253,000	2,163,000	2,083,000	8,854,000
Price per Bbl	$ 55.15	$ 55.11	$ 55.14	$ 55.16	$ 55.14

(a) The index prices for the oil price swaps are based on the NYMEX – WTI monthly average futures price.

Concho Resources Inc.
Unaudited Supplementary Data
December 31, 2016, 2015 and 2014

Capitalized costs

(in thousands)	**December 31, 2016**	**2015**
Oil and natural gas properties:		
Proved	$ 16,619,875	$ 14,940,259
Unproved	1,856,404	906,048
Less: accumulated depletion	(7,389,844)	(5,047,810)
Net capitalized costs for oil and natural gas properties	$ 11,086,435	$ 10,798,497

Costs incurred for oil and natural gas producing activities

(in thousands)	**Years Ended December 31, 2016**	**2015**	**2014**
Property acquisition costs:			
Proved	$ 981,855	$ 57,190	$ 99,362
Unproved	1,154,423	206,214	292,363
Exploration	701,300	1,122,587	1,615,238
Development	448,409	709,088	937,491
Total costs incurred for oil and natural gas properties	$ 3,285,987	$ 2,095,079	$ 2,944,454

The table below provides the amount of asset retirement obligations included in the costs incurred table shown above:

(in thousands)	**Years Ended December 31, 2016**	**2015**	**2014**
Exploration costs	$ 1,067	$ 1,820	$ 2,589
Development costs	1,046	(9,084)	7,488
Total asset retirement obligations (a)	$ 2,113	$ (7,264)	$ 10,077

(a) The downward revision to the Company's asset retirement obligation estimates for the year ended December 31, 2015 is primarily due to a reduction in the future estimated abandonment costs.

Concho Resources Inc.
Unaudited Supplementary Data
December 31, 2016, 2015 and 2014

Reserve Quantity Information

The following information represents estimates of the Company's proved reserves as of December 31, 2016. The pricing that was used for estimates of the Company's reserves as of December 31, 2016 was based on the SEC pricing of $39.25 per Bbl West Texas Intermediate posted oil price and $2.48 per MMBtu Henry Hub spot natural gas price. See table below.

Subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This rule limited, and may continue to limit, the Company's potential to record additional proved undeveloped reserves as it pursues its drilling program, particularly as it develops its significant acreage in the Permian Basin of Southeast New Mexico and West Texas. Moreover, the Company may be required to write down its proved undeveloped reserves if it does not drill on those reserves within the required five-year timeframe. All of the Company's recorded proved undeveloped reserves are scheduled to be drilled within five years of initial disclosure.

The Company's proved oil and natural gas reserves are all located in the United States, primarily in the Permian Basin of Southeast New Mexico and West Texas. All of the estimates of the proved reserves at December 31, 2016, 2015 and 2014 are based on reports prepared by Cawley, Gillespie & Associates, Inc. and Netherland, Sewell & Associates, Inc., independent petroleum engineers. Proved reserves were estimated in accordance with the guidelines established by the SEC and the FASB.

The following table summarizes the prices utilized in the reserve estimates for 2016, 2015 and 2014. Commodity prices utilized for the reserve estimates prior to adjustments for location, grade and quality are as follows:

	December 31,		
	2016	**2015**	**2014**
Prices utilized in the reserve estimates before adjustments:			
Oil per Bbl	$ 39.25	$ 46.79	$ 91.48
Natural gas per MMBtu	$ 2.48	$ 2.59	$ 4.35

Oil and natural gas reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and natural gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

Concho Resources Inc.
Unaudited Supplementary Data
December 31, 2016, 2015 and 2014

The following table provides a rollforward of the total proved reserves for the years ended December 31, 2016, 2015 and 2014, as well as proved developed and proved undeveloped reserves at the beginning and end of each respective year. Oil and condensate volumes are expressed in MBbls and natural gas volumes are expressed in MMcf.

	2016			2015			2014		
	Oil and Condensate (MBbls)	Natural Gas (MMcf)	Total (MBoe)	Oil and Condensate (MBbls)	Natural Gas (MMcf)	Total (MBoe)	Oil and Condensate (MBbls)	Natural Gas (MMcf)	Total (MBoe)
Total Proved Reserves:									
Balance, January 1	367,784	1,534,063	623,461	370,347	1,601,015	637,183	307,382	1,173,240	502,921
Purchases of minerals-in-place	40,992	108,484	59,073	7,083	27,722	11,703	2,543	18,970	5,705
Sales of minerals-in-place	(5,797)	(14,778)	(8,259)	(944)	(2,610)	(1,379)	-	-	-
Extensions and discoveries	83,617	246,928	124,771	97,208	359,161	157,068	115,389	400,329	182,111
Revisions of previous estimates	(24,721)	4,376	(23,992)	(71,453)	(344,238)	(128,826)	(28,648)	95,812	(12,679)
Production	(33,840)	(127,481)	(55,087)	(34,457)	(106,987)	(52,288)	(26,319)	(87,336)	(40,875)
Balance, December 31	428,035	1,751,592	719,967	367,784	1,534,063	623,461	370,347	1,601,015	637,183
Proved Developed Reserves:									
January 1	203,880	926,629	358,318	211,446	992,567	376,874	179,520	742,417	303,255
December 31	267,203	1,190,330	465,591	203,880	926,629	358,318	211,446	992,567	376,874
Proved Undeveloped Reserves:									
January 1	163,904	607,434	265,143	158,901	608,448	260,309	127,862	430,823	199,666
December 31	160,832	561,262	254,376	163,904	607,434	265,143	158,901	608,448	260,309

For the year ended December 31, 2016:

Purchases and sales of minerals-in-place. The Company's purchases of minerals-in-place are composed of approximately 42.1 MMBoe from the October 2016 Reliance Acquisition, 14.8 MMBoe from the March 2016 Southern Delaware Basin acquisition and 2.2 MMBoe from various other acquisitions throughout the year. The Company's sales of minerals-in-place are composed of approximately 8.3 MMBoe from various divestitures throughout the year.

Extensions and discoveries. Extensions and discoveries of approximately 124.8 MMBoe are primarily the result of the Company's continued success from its extension and infill horizontal drilling programs in its core operating areas. Proved developed reserves increased approximately 61.1 MMBoe due to the Company's exploratory drilling activity last year. Based upon this activity, approximately 63.7 MMBoe of new proved undeveloped locations were added, of which the majority are one offset location from an existing producing well.

Revisions of previous estimates. Revisions of previous estimates are comprised of (i) 57.4 MMBoe of negative revisions due to proved undeveloped reserves reclassified to unproved reserves because they are no longer expected to be developed within five years of their initial recording and (ii) 29.9 MMBoe of negative price revisions, partially offset by 63.3 MMBoe of net positive revisions related to lower lease operating expense estimates. The 57.4 MMBoe of proved undeveloped reserves in item (i) above are outside the five-year development window primarily due to results the Company has obtained during 2016 related to increased testing and implementation of new technologies that allows for drilling extended length laterals. The results are generally highly successful and provide sufficient data that substantiates drilling extended length laterals is generally a more efficient process than shorter lateral drilling to recover reserves. The results also generally confirm that the drilling of longer laterals is feasible on a large scale and substantially decreases the risks associated with a drilling program more focused on extended length laterals. Consequently, the Company shifted its capital program to focus on drilling more extended length laterals.

For the year ended December 31, 2015:

Purchases and sales of minerals-in-place. The Company's purchases of minerals-in-place are composed of approximately 11.7 MMBoe from various acquisitions throughout the year and 1.4 MMBoe from various divestitures throughout the year.

Extensions and discoveries. Extensions and discoveries of approximately 157.1 MMBoe are primarily the result of the Company's continued success from its extension and infill horizontal drilling programs in its core operating areas. There were approximately 54.8 MMBoe of proved developed reserves that were directly added through the Company's drilling activity last year. Based upon this activity, approximately 102.3 MMBoe of new proved undeveloped locations were added, of which the vast majority are one offset location from an existing producing well.

Revisions of previous estimates. Revisions of previous estimates are comprised of (i) 112.2 MMBoe of negative price revisions, (ii) 10.9 MMBoe of negative revisions due to proved undeveloped reserves reclassified to unproved reserves because they are no longer expected to be developed within the five years of their initial recording required by SEC rules and (iii) 5.7 MMBoe net negative revision resulting from technical and performance evaluations.

For the year ended December 31, 2014:

Purchases and sales of minerals-in-place. In 2014, the Company's purchases of minerals-in-place were composed of approximately 5.7 MMBoe from various acquisitions throughout the year.

Extensions and discoveries. In 2014, extensions and discoveries of approximately 182.1 MMBoe were primarily the result of the Company's continued success from its extension and infill horizontal drilling programs in its core operating areas. There were approximately 61.3 MMBoe of proved developed reserves that were directly added through the Company's drilling activity last year. Based upon this activity, approximately 120.8 MMBoe of new proved undeveloped locations were added, of which, approximately 73.2 MMBoe of proved undeveloped reserves were one offset location from an existing producing well. In addition, within some of the Company's core operating areas, one or more reliable technologies supported additional proved undeveloped locations that were more than one offset away from a producing well. There were approximately 300 such proved undeveloped locations added based on reliable technology. These locations resulted in 47.6 MMBoe of net proved reserves.

Revisions of previous estimates. In 2014, revisions of previous estimates were comprised of (i) 36.2 MMBoe of proved undeveloped reserves reclassified to unproved reserves because they are no longer expected to be developed within the five years of their initial recording required by SEC rules, (ii) a 23.6 MMBoe net positive revision resulting from both positive and negative technical and performance evaluations and (iii) 0.1 MMBoe of negative price revisions.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows is computed by applying the 12-month unweighted average of the first-day-of-the-month pricing for oil and natural gas (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved oil and natural gas reserves less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, discounted using a rate of 10 percent per year to reflect the estimated timing of the future cash flows. Future income taxes are calculated by comparing undiscounted future cash flows to the tax basis of oil and natural gas properties plus available carryforwards and credits and applying the current tax rates to the difference.

Discounted future cash flow estimates like those shown below are not intended to represent estimates of the fair value of oil and natural gas properties. Estimates of fair value would also consider probable and possible reserves, anticipated future oil and natural gas prices, interest rates, changes in development and production costs and risks associated with future production. Because of these and other considerations, any estimate of fair value is necessarily subjective and imprecise.

Concho Resources Inc.
Unaudited Supplementary Data
December 31, 2016, 2015 and 2014

The following table provides the standardized measure of discounted future net cash flows at December 31, 2016, 2015 and 2014:

	December 31,		
(in thousands)	**2016**	**2015**	**2014**
Oil and gas producing activities:			
Future cash inflows	$ 20,674,021	$ 20,133,330	$ 42,162,518
Future production costs	(7,944,654)	(7,667,091)	(11,878,549)
Future development and abandonment costs (a)	(2,458,538)	(3,357,362)	(4,665,495)
Future income tax expense	(1,382,054)	(1,119,143)	(7,565,280)
Future net cash flows	8,888,775	7,989,734	18,053,194
10% annual discount factor	(4,698,555)	(4,250,249)	(10,030,367)
Standardized measure of discounted future net cash flows	$ 4,190,220	$ 3,739,485	$ 8,022,827

(a) Includes \$230.7 million, \$196.5 million and \$203.9 million of undiscounted asset retirement cash outflow estimated at December 31, 2016, 2015 and 2014, respectively, using current estimates of future abandonment costs less salvage values. See Note 5 for corresponding information regarding the Company's discounted asset retirement obligations.

Changes in Standardized Measure of Discounted Future Net Cash Flows

The following table provides a rollforward of the standardized measure of discounted future net cash flows for the years ended December 31, 2016, 2015 and 2014:

	Years Ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Oil and natural gas producing activities:			
Purchases of minerals-in-place	$ 497,154	$ 73,676	$ 102,032
Sales of minerals-in-place	(61,521)	(4,991)	-
Extensions and discoveries	1,115,784	1,021,693	3,353,339
Development costs incurred during the period	278,098	464,697	561,198
Net changes in prices and production costs	(935,491)	(7,892,682)	(645,947)
Oil and natural gas sales, net of production costs	(1,183,684)	(1,262,214)	(2,121,773)
Changes in future development costs	590,427	987,800	310,326
Revisions of previous quantity estimates	(188,521)	(1,125,226)	(250,401)
Accretion of discount	404,787	1,064,504	906,661
Changes in production rates, timing and other	61,410	(448,804)	139,885
Change in present value of future net revenues	578,443	(7,121,547)	2,355,320
Net change in present value of future income taxes	(127,708)	2,838,205	(576,928)
	450,735	(4,283,342)	1,778,392
Balance, beginning of year	3,739,485	8,022,827	6,244,435
Balance, end of year	$ 4,190,220	$ 3,739,485	$ 8,022,827

Concho Resources Inc.
Unaudited Supplementary Data
December 31, 2016, 2015 and 2014

Selected Quarterly Financial Results

The following table provides selected quarterly financial results for the years ended December 31, 2016 and 2015:

	Quarter			
(in thousands, except per share data)	**First**	**Second**	**Third**	**Fourth**
Year ended December 31, 2016:				
Total operating revenues	$ 283,564	$ 396,299	$ 430,548	$ 524,577
Operating costs and expenses (excluding gains (losses) on derivatives)	(1,916,985)	(468,703)	(469,157)	(480,903)
Gains (losses) on derivatives	79,842	(296,694)	41,186	(193,018)
Income (loss) from operations	$ (1,553,579)	$ (369,098)	$ 2,577	$ (149,344)
Net loss	$ (1,020,480)	$ (265,685)	$ (51,146)	$ (125,135)
Earnings per common share - Basic	$ (7.95)	$ (2.04)	$ (0.38)	$ (0.86)
Earnings per common share - Diluted	$ (7.95)	$ (2.04)	$ (0.38)	$ (0.86)
Year ended December 31, 2015:				
Total operating revenues	$ 413,522	$ 537,425	$ 463,474	$ 389,152
Operating costs and expenses (excluding gains (losses) on derivatives)	(459,329)	(523,638)	(551,844)	(641,300)
Gains (losses) on derivatives	115,340	(147,399)	413,130	318,681
Income (loss) from operations	$ 69,533	$ (133,612)	$ 324,760	$ 66,533
Net income (loss)	$ 7,512	$ (120,483)	$ 179,659	$ (788)
Earnings per common share - Basic	$ 0.07	$ (1.02)	$ 1.49	$ (0.01)
Earnings per common share - Diluted	$ 0.06	$ (1.02)	$ 1.49	$ (0.01)

FORWARD-LOOKING STATEMENT

The foregoing contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical fact, included in this annual report that address activities, events or developments that Concho Resources Inc. (the "Company") expects, believes or anticipates will or may occur in the future are forward-looking statements. Forward-looking statements contained in this annual report specifically include statements, estimates and projections regarding the Company's future financial position, operations, performance, business strategy, oil and natural gas reserves, drilling program, capital expenditure budget, liquidity and capital resources, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, derivative activities and potential financing. The words "estimate," "project," "predict," "believe," "expect," "anticipate," "potential," "could," "may," "foresee," "plan," "goal" or other similar expressions that convey the uncertainty of future events or outcomes are intended to identify forward-looking statements, which generally are not historical in nature. However, the absence of these words does not mean that the statements are not forward-looking. These statements are based on certain assumptions and analyses made by the Company based on management's experience, expectations and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate. Forward-looking statements are not guarantees of performance. Although the Company believes the expectations reflected in its forward-looking statements are reasonable and are based on reasonable assumptions, no assurance can be given that these assumptions are accurate or that any of these expectations will be achieved (in full or at all) or will prove to have been correct. Moreover, such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. These include the risk factors discussed or referenced in the Company's most recent Annual Report on Form 10-K; risks relating to declines in, or the sustained depression of, the prices the Company receives for its oil and natural gas; uncertainties about the estimated quantities of oil and natural gas reserves; drilling, completion and operating risks; the adequacy of the Company's capital resources and liquidity including, but not limited to, access to additional borrowing capacity under the Company's credit facility; the effects of government regulation, permitting and other legal requirements, including new legislation or regulation of hydraulic fracturing and the export of oil and natural gas; the impact of potential changes in the Company's credit ratings; environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater contamination; difficult and adverse conditions in the domestic and global capital and credit markets; risks related to the concentration of the Company's operations in the Permian Basin of southeast New Mexico and west Texas; disruptions to, capacity constraints in or other limitations on the pipeline systems that deliver the Company's oil, natural gas liquids and natural gas, and other processing and transportation considerations; the costs and availability of equipment, resources, services and qualified personnel required to perform the Company's drilling and operating activities; potential financial losses or earnings reductions from the Company's commodity price risk-management program; risks and liabilities related to the integration of acquired properties or businesses; uncertainties about the Company's ability to successfully execute its business and financial plans and strategies; uncertainties about the Company's ability to replace reserves and economically develop its current reserves; general economic and business conditions, either internationally or domestically; competition in the oil and natural gas industry; uncertainty concerning the Company's assumed or possible future results of operations; and other important factors that could cause actual results to differ materially from those projected.

This annual report includes financial measures that are not in accordance with generally accepted accounting principles ("GAAP"), including EBITDAX. While management believes that such measures are useful for investors, they should not be used as a replacement for financial measures that are in accordance with GAAP. For a reconciliation of EBITDAX to the nearest comparable measure in accordance with GAAP, please see "Item 1. Business --Non-GAAP Financial Measure" in our 2016 Annual Report on Form 10-K included herein. We also disclose reserves replacement ratio and finding and development costs in this annual report.

The Company may use the terms "unproved reserves," "resource potential," "EUR" per well and "upside potential" to describe estimates of potentially recoverable hydrocarbons that the U.S. Securities and Exchange Commission ("SEC") rules prohibit from being included in filings with the SEC. These are based on analogy to the Company's existing models applied to additional acres, additional zones and tighter spacing, and are the Company's internal estimates of hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques. These quantities may not constitute "reserves" within the meaning of the Society of Petroleum Engineers' Petroleum Resources Management System or SEC rules. EUR estimates, resource potential and identified drilling locations have not been fully risked by Company management and are inherently more speculative than proved reserves estimates.

Actual locations drilled and quantities that may be ultimately recovered from the Company's interests could differ substantially. There is no commitment by the Company to drill all of the drilling locations which have been attributed to these quantities. Factors affecting ultimate recovery include the scope of the Company's ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals, actual drilling results, including geological and mechanical factors affecting recovery rates, and other factors. Estimates of unproved reserves, resource potential, per well EUR and upside potential may change significantly as development of the Company's oil and natural gas assets provide additional data. The Company's production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.

Any forward-looking statement speaks only as of the date on which such statement is made, and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

CONCHO

CONCHO RESOURCES INC.

Concho is an independent oil and natural gas company engaged in the acquisition, development, exploration and production of oil and natural gas properties. Our operations are focused in the Permian Basin of southeast New Mexico and west Texas. At year-end 2016, Concho owned interests in over 7,800 gross producing wells and had proved reserves of 720 million barrels of oil equivalent.

Since our formation, Concho has grown both reserves and production at a compound annual growth rate of 26% and 30%, respectively, and high-graded our Permian acreage position to approximately 900,000 gross acres. Our success is a direct result of pursuing high-quality assets, executing a large, safe and efficient drilling program and maintaining a strong financial position.

DIRECTORS

Tim Leach

Steve Beal

Tucker Bridwell

Bill Easter

Susan Helms

Gary Merriman

Ray Poage

Mark Puckett

John Surma

EXECUTIVE OFFICERS

Tim Leach
Chairman of the Board, Chief Executive Officer and President

Will Giraud
Executive Vice President, Chief Commercial Officer and Corporate Secretary

Jack Harper
Executive Vice President and Chief Financial Officer

Joe Wright
Executive Vice President and Chief Operating Officer

Steve Guthrie
Senior Vice President of Business Operations and Engineering

CORPORATE OFFICERS

Mona Ables
Vice President of Land

Clay Bateman
Vice President of New Mexico

Mary Ann Berry
Vice President, Chief of Staff and Assistant Corporate Secretary

Gayle Burleson
Vice President of Business Development

Kang Chen
Vice President and Chief Information Officer

Keith Corbett
Vice President of Texas

Travis Counts
Vice President, General Counsel and Assistant Corporate Secretary

Megan P. Hays
Vice President of Investor Relations

Scott Kidwell
Vice President of Government and Public Affairs

Price Moncrief
Vice President of Capital Markets and Strategy

Erick Nelson
Vice President of Operations and Production

Ray Peterson
Vice President of Drilling

Brenda Schroer
Vice President, Chief Accounting Officer and Treasurer

STOCKHOLDER INFO.

Corporate Headquarters
Concho Resources Inc.
600 West Illinois Avenue
Midland, Texas 79701

Phone: 432.683.7443
Fax: 432.683.7441

Transfer Agent
American Stock Transfer
& Trust Company
59 Maiden Lane
New York, New York 10038
www.amstock.com

Stock Exchange
Common stock traded on the New York Stock Exchange under the symbol: CXO

Corporate Counsel
Vinson & Elkins LLP
1001 Fannin, Suite 2500
Houston, Texas 77002

Phone: 713.758.2222

Independent Auditors
Grant Thornton LLP
211 N. Robinson, Suite 1200
Oklahoma City, OK 73102

Phone: 405.218.2800

Annual Meeting
The Annual Meeting for Concho Resources Inc. shareholders will be held at the Petroleum Club of Midland on May 17, 2017.

Form 10-K
For an additional copy of the Annual Report on Form 10-K, please contact:

Concho Resources Inc.
Attn: Investor Relations
Phone: 432.683.7443
Email: IR@concho.com
www.concho.com

CONCHO

600 WEST ILLINOIS AVENUE, MIDLAND, TEXAS 79701

WWW.CONCHO.COM